DRAFT TECHNICAL SUPPORT DOCUMENT FOR THE EXPANSION OF THE COMPARABLE FUELS EXCLUSION

U.S. Environmental Protection Agency
Office of Solid Waste and Emergency Response
1200 Pennsylvania, NW
Washington, D.C. 20460

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1 Introduction

The United States Environmental Protection Agency (EPA) is proposing to revise the RCRA comparable fuel exclusion under 40 CFR 261.38 by expanding the conditional exclusion from RCRA for fuels that are produced from a hazardous waste but which generate emissions when burned in an industrial boiler that are comparable to emissions from burning fuel oil. The revised rule would establish a new category of excluded waste fuel called emission-comparable fuel (ECF).

ECF is a hazardous waste-derived fuel product that meets the specifications for comparable fuel under §261.38(a) except the specifications for certain hydrocarbons and oxygenates.[1] Generators who claim the exclusion and burners must comply with various conditions for handling and storage. In addition, ECF must be burned in an industrial, watertube, steam boiler under specified combustion conditions that ensure that emissions from combustion of ECF are comparable to emissions from combustion of fuel oil.

1.1 Background

<u>Comparable Fuels Exclusion (1998)</u>: The comparable fuels exclusion was promulgated on June 19 1998 and is codified in 40 CFR 261.38 (See 63 FR 33782). The rule excludes waste fuels from the definition of solid wastes if they have levels of toxic constituents and physical properties similar to commercial (benchmark) fuels, in particular gasoline and fuel oils. Comparable fuels must meet certain specifications for physical properties and constituents:

- Physical Properties: The heating value of the fuel must exceed 5000 Btu/lb (as-generated) and kinematic viscosity (as-fired) must be less than 50 centistokes.
- Constituent Specification: The fuel must meet specifications for 14 metals and approximately 176 organic compounds listed in Table 1 of 40 CFR 261.38. The organics include:[2]
    - 13 Hydrocarbons
    - 24 Oxygenates
    - 9 Sulfonated organics
    - 61 Nitrogenated organics
    - 79 Halogenated organics.

Additionally there are specifications for total nitrogen, total halogen, total PCBs and total cyanide. The development of the specifications is summarized below and is discussed in detail in the technical support document that accompanied the final rule.[3]

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[1] See section 2.1 for a definition of ECF.

[2] Each of these five groups included Volatile Organic Compounds (VOC) and Semi-Volatile Organic Compounds (SVOC)

[3] See USEPA, "Final Technical Support Document for HWC MACT Standards Volume VI: Development of Comparable Fuels Specifications", May 1998.

The comparable fuel rule also restricts burning of comparable fuels to certain types of combustions units (including boilers, industrial furnaces, incinerators and gas turbines) as defined in 40 CFR 261.38(c)(2)

Technical Amendments (1999)**:** EPA issued technical amendments to the final rule on September 30, 1999. (See 64 FR 53027). These amendments include numerous changes to the specification tables for metals and organics. The changes were primarily due to errors in applying EPA's methodology for determining the specification level. The amendments are described in USEPA, "Final Technical Support Document of HWC MACT Standards, Vol IV: Compliance, July 1999.

Development of the Specification Table: In the 1998 rulemaking, the individual constituent specifications for organics (and metals) were developed based on four benchmark liquid fossil fuels (gasoline and three grades of fuel oil). Samples were collected from eight geographic regions across the country. A total of 27 samples were collected. These included:

- Gasoline (8 samples),
- Fuel oil #2 (11 samples),
- Fuel oil #4 (1 sample) and
- Fuel oil #6 (7 samples)

These samples were analyzed for all 40 CFR Part 261 Appendix VIII hazardous constituents that were measurable. The analyses for organics included SW-846 method 8240 (Volatile Organics by GC/MS)[4] and method 8270A (GC/MS for semivolatile organics).

The comparable fuels specifications for organics were based on the highest level observed in the benchmark fuels. However, two approaches were used depending on whether a constituent was detected in any of the samples. (Note that only benzene, naphthalene, and toluene were detected in any of the samples.)

1. If a constituent were detected in any of the samples, the detect level(s) was normalized to 10,000 Btu/lb based on the measured heating value of the sample. The specification was the higher of.
   a. Highest observed laboratory quantitation limit (QL) for nondetect samples
   b. Highest normalized concentration limit for detected samples.

2. If a constituent were not detected in any of the samples, the highest laboratory quantitation limit was used. However, for VOC constituents which were not detected in any gasoline samples**,** the gasoline QLs were deemed unreliable and

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[4] Method 8240 has been discontinued and replaced by Method 8260. The newer method uses a capillary GC instead of a column GC.

not used.[5] Therefore the specification for nondetect VOCs were based on the highest QL among the fuel oil samples.

Note that for organic nondetects, the specification is nondetect at a minimum detection limit—the quantitation limit for the benchmark fuels analyses--except for hydrocarbons and oxygenates where the specification is the quantitation limit because these compounds could be expected to be found in benchmark fuels

1.2 Motivation

Using excluded hazardous waste as fuel saves energy by reducing the amount of hazardous wastes that would otherwise be treated and disposed, promotes energy production from domestic, renewable sources, and reduces the use of fossil fuel.[6] As part of the Resource Conservation Challenge, EPA is examining the effectiveness of the current comparable fuels program and is considering whether other industrial wastes could be used as fuel.[7]

EPA contacted the American Chemistry Council (ACC) in early 2003 to determine to what extent the comparable fuels program was being utilized and if additional industrial waste streams could be excluded. ACC distributed a survey to its members in Spring 2003 and provided the results to EPA in late 2003.[8]

ACC provided EPA with responses from 52 surveys representing 14 companies. The survey provided information on both qualifying and nonqualifying fuels on a waste stream by waste stream basis. For qualifying fuels (i.e. those that are meeting the comparable fuels exclusion), information included annual quantity produced, heating value of the waste, whether or not the exclusion was being used, and the combustion device that was used or anticipated to be used. For nonqualifying fuels that ACC believed were candidates for an expanded definition of comparable fuels, the data provided included:[9]

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[5] Gasoline has a higher fraction of volatiles than fuel oil and matrix interferences required larger dilution factors for the samples. Additionally, more dilution was required for gasoline to quantify one the hydrocarbon VOCs (toluene) within the GC/MS calibration range. The higher dilution factors result in high detection limits for nondetect substances. EPA believed that waste fuels are likely to have a composition more similar to fuel oil than gasoline, and thus the matrix interferences for waste fuels would be more similar to fuel oil than gasoline. Therefore, EPA believed it was appropriate to base the specifications for VOCs that were not detected in gasoline on fuel oil QLs rather than gasoline QLs.

[6] USEPA, “Spring 2006 Regulatory Agenda”, Sequence # 3245- Expanding the Comparable Fuels Exclusion under RCRA.

[7] However, expanding the comparable fuel exclusion may not substantially increase the amount of hazardous waste burned for energy recovery because high Btu wastes, even though not currently excluded from RCRA, are currently burned in industrial furnaces and incinerators for their fuel value. Nonetheless, continuing to regulate these waste-derived fuels as hazardous wastes would treat a potentially valuable fuel commodity (especially considering the increasing value of fuels) as a waste without a compelling basis.

[8] Letter from American Chemistry Council (Carter Lee Kelly, Leader, Waste Issues Team, and Robert A. Elam, Director, Regulatory Affairs, Waste Issues Team) to Robert Springer and Matt Hale, USEPA, dated November 24, 2003.

[9] Not all information was provided for every waste stream. In fact about 20% of these waste streams had insufficient information for further analysis.

- Annual quantity of waste generated.
- Heating value of waste.
- Description of waste and primary constituents.
- Constituents failing CFE specifications and limits achievable.
- Current disposal method.
- Burn location (onsite vs. offsite) and combustion device used.
- Availability of CO CEMS and ability to meet a CO limit of 100 ppmv.

Additionally, the survey respondents identified barriers to a larger scale use of the exclusion and recommended changes to the current specification. ACC and EPA narrowed respondents' suggestions down to three potential revisions:

- Conditional Exclusion of fuels that are off-specification for hydrocarbons and oxygenates where the conditions ensure emissions are comparable to fuel oil emissions.
- Change specifications for seven volatile oxygenates to base them on gasoline quantitation limits rather than fuel oil quantitation limits
- Allow blending to meet the specifications for hydrocarbons and oxygenates

Note however that EPA is proposing only the first revision at this time because it appears that the other revisions would have limited utility because few if any additional waste streams would be excluded.

1.3 Summary of Proposed Expansion

EPA is proposing to exclude emission-comparable fuel (ECF) from the definition of RCRA solid waste under the following primary conditions:

1. ECF must be burned in a boiler meeting the design requirements and under combustion conditions summarized below.
2. ECF must be stored in compliance with certain storage provisions summarized below.

Boiler Conditions: Excluded ECF must be burned in boiler meeting certain design criteria and under certain burner conditions that are associated with good combustion practice. These include the condition that ECF be burned in a watertube steam boiler (excluding stokers) and specific combustion conditions:

a) CO emissions, monitored by a CEMS, must be less than 100 ppmv @ 7% O_2.
b) The boiler must fire at least 50% fossil fuel.
c) The boiler load must be greater than 40%.
d) The ECF must be fired into the flame of the primary fuel.
e) The boiler must provide sufficient atomization for ECF streams.
f) Units with dry air pollution control devices must maintain the gas inlet temperature below 400°F unless coal is the primary fuel.

g) The CO monitor and the gas temperature monitor (if applicable) must be linked to the automatic ECF feed cutoff system. [10]

Storage Conditions- ECF may be stored in a tank, tank car, or tank truck. See proposed §261.38(c)(1). Above ground tank systems would be subject to: (1) the Spill Prevention and Control Countermeasure (SPCC) requirements of (primarily) 40 CFR 112.7 and 112.8 as though ECF met the definition of oil; (2) engineered secondary containment requirements (i.e., a liner, vault, or double-walled tank) and leak detection requirements applicable to hazardous waste tanks; (3) certain containment and detection of release provisions adopted from requirements applicable to hazardous waste tanks; (4) certain preparedness and prevention, emergency procedures and response to releases provisions applicable to hazardous waste tanks; and (5) conditions that control fugitive emissions from tanks, as adopted from requirements applicable to Organic Liquids Distribution under 40 CFR 63 Subpart EEEE, Part 63. Underground tanks storing ECF would be subject to 40 CFR Part 280.

In addition ECF would be subject to all of the management and implementation conditions applicable to existing comparable fuel.

The rest of this document presents supporting information for the proposed expansion of the comparable fuels rulemaking. Section 2 discusses ECF constituents with a particular emphasis on the 37 oxygenates and hydrocarbons for which specifications are currently provided in Table 1 to §261.38. In addition, a relative hazard ranking scheme for the 37 oxygenates and hydrocarbons is described in this section. Section 3 provides information on the industrial boiler designs and fuels used in these boilers. Section 4 discusses the use of CO as an indicator for incomplete combustion. In Section 5 we describe a qualitative risk assessment conducted for dioxins and furans and compare organics data between hazardous waste burning boilers and industrial boilers. The compliance conditions for ECF generators and burners are described in Section 6, and, finally, the costs and savings for generators and burners are presented in Section 7.

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[10] Only a summary of the combustion control requirements are presented here. See the preamble to the proposed rule Part 2; Section IIB for a complete description. Also see Section 6 of this technical support document.

2 Constituents of Emission-Comparable Fuel

This section begins by defining emission-comparable fuels. This is followed by a discussion of the properties of the 37 oxygenates and hydrocarbons for which specifications are provided in Table 1 to §261.38 and a discussion of a relative hazard ranking scheme for these constituents.

2.1 Definition of Emission-Comparable Fuel

Emission-comparable fuels must meet the following physical and constituent specifications.

<u>*Physical specifications*</u>

- *Heating value.* The heating value must exceed 5,000 Btu/lb (11,500 J/g) as-generated.[11]

- *Viscosity.* The viscosity must not exceed 50 centistokes, as-fired.

<u>*Constituent specification*</u>

(A) The specification levels and, where nondetect is the specification, minimum required detection limits, are listed in the Table 1 to §261.38. Note the specifications would be waived for the compounds listed below.

(B) *Waived specifications.* The specification levels in Table 1 would not apply for the following hydrocarbons and oxygenates under the special conditions provided for emission-comparable fuel:[12]

1. Benzene (CAS No. 71-43-2)
2. Toluene (CAS No. 108-88-3)
3. Acetophenone (CAS No. 98-86-2)
4. Acrolein (CAS No. 107-02-8)
5. Allyl alcohol (CAS No. 107-18-6)
6. Bis(2-ethylhexyl)phthalate [Di-2-ethylhexyl phthalate] (CAS No.117-81-7)
7. Butyl benzyl phthalate (CAS No. 85-68-7)
8. o-Cresol [2-Methyl phenol] (CAS No. 95-48-7)
9. m-Cresol [3-Methyl phenol] (CAS No. 108-39-4)
10. p-Cresol [4-Methyl phenol] (CAS No.106-44-5)
11. Di-n-butyl phthalate (CAS No. 84-74-2)

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[11] Note that hazardous waste may be treated by bona fide means (e.g., other than blending) to achieve a heating value of 5,000 Btu/lb. Note also that ECF must have an as-fired heating value of 8,000 Btu/lb. Consequently, ECF may be blended with other fuels to achieve the 8,000 Btu/lb as-fired heating value.

[12] This list of substances for which specification would be waived includes all 24 oxygenates and two of the thirteen hydrocarbons (benzene and toluene) that are in Table 1 to §261.38. Note that the specifications are unchanged for the remaining 11 hydrocarbons, other organics (nitrogenated, sulfonated, and halogenated organics), metals and other compounds listed in the table.

12. Diethyl phthalate (CAS No. 84-66-2)
13. 2,4-Dimethylphenol (CAS No. 105-67-9)
14. Dimethyl phthalate (CAS No. 131-11-3)
15. Di-n-octyl phthalate (CAS No. 117-84-0)
16. Endothall (CAS No. 145-73-3)
17. Ethyl methacrylate (CAS No. 97-63-2)
18. 2-Ethoxyethanol [Ethylene glycol monoethyl ether] (CAS No. 110-80-5)
19. Isobutyl alcohol (CAS No. 78-83-1)
20. Isosafrole (CAS No. 120-58-1)
21. Methyl ethyl ketone [2-Butanone] (CAS No. 78-93-3)
22. Methyl methacrylate (CAS No. 80-62-6)
23. 1,4-Naphthoquinone (CAS No. 130-15-4)
24. Phenol (CAS No. 108-95-2)
25. Propargyl alcohol [2-Propyn-1-ol] (CAS No. 107-19-7)
26. Safrole (CAS No. 94-59-7)

The remaining parts of this section discuss the properties of oxygenates and hydrocarbons listed in Table 1 to §261.38 and the rationale for not waiving the specification for particular hydrocarbons.

2.2 Properties of Oxygenates and Hydrocarbons.

Hydrocarbons occur naturally in virgin fossil fuels. Oxygenates are a class of compounds that are added to gasoline to improve combustion and reduce carbon monoxide emissions.[13]

The 37 hydrocarbons and oxygenates that are part of the current comparable fuel specification are shown in Table 2-1. For each compound the table displays:

- The chemical abstract service (CAS) number,
- The composition of constituent found in benchmark fuels, and
- The current concentration limit for comparable fuels.

All the hydrocarbons in the table are aromatics. Ten of the 13 hydrocarbon compounds (benzene, toluene, and naphthalene are the exceptions) belong to a group of compounds referred to as Polycyclic Aromatic Hydrocarbons (PAH).[14] The oxygenates belong to various classes of organic compounds including alcohols, aldehydes, ketones, and phthalates.

Table 2-1 also shows physical properties such as molecular weight, boiling point, vapor pressure, and heating value for each of the compounds. Each of the physical properties is briefly discussed below:

<u>Molecular Weight:</u> The molecular weights of the 37 hydrocarbons and oxygenates range from 56 g/gmol for acrolein to 390 g/gmol for di-n octyl phthalate.

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[13] See discussion in Section 3.1.1

[14] Note that naphthalene is also sometimes classified as a PAH. See also Section 2.4

Chemical Name	CAS Number	Formula	Composite Value in benchmark fuel (mg/kg)	Concentration Limit (mg/kg at 10,000 BTU/lb)	VOC/ SVOC	Specific Gravity	Molecular Weight (g/gmol)	Boiling Point (°C)	Vapor Pressure @ 25 °C (mm Hg)	(kPa)	Heating Value (Btu/lb)
Hydrocarbons											
Benzo[a]anthracene	56-55-3	$C_{18}H_{12}$	ND	2400	SVOC		228	438	1.5E-07	2.1E-08	17,043
Benzene	71-43-2	C_6H_6	8000	4100	VOC	0.88	78	80	9.6E+01	1.3E+01	18,061
Benzo[b]fluoranthene	205-99-2	$C_{20}H_{12}$	ND	2400	SVOC		252	357	8.1E-08	1.1E-08	16,668
Benzo[k]fluoranthene	207-08-9	$C_{20}H_{12}$	ND	2400	SVOC		252	480	9.6E-11	1.3E-11	16,805
Benzo[a]pyrene	50-32-8	$C_{20}H_{12}$	ND	2400	SVOC		252	495	4.9E-09	6.5E-10	16,608
Chrysene	218-01-9	$C_{20}H_{12}$	ND	2400	SVOC		228	448	7.8E-09	1.0E-09	16,885
Dibenzo[a,h]anthracene	53-70-3	$C_{22}H_{14}$	ND	2400	SVOC		278	524	2.1E-11	2.8E-12	16,935
7,12-Dimethylbenz[a]anthracene	57-97-6	$C_{20}H_{16}$	ND	2400	SVOC		256	440	4.0E-10	5.4E-11	17,512
Fluoranthene	206-44-0	$C_{16}H_{10}$	ND	2400	SVOC		202	375	8.1E-06	1.1E-06	16,849
Indeno(1,2,3-cd)pyrene	193-39-5	$C_{22}H_{12}$	ND	2400	SVOC		276	536	1.4E-10	1.9E-11	15,353
3-Methylcholanthrene	56-49-5	$C_{21}H_{16}$	ND	2400	SVOC		268	280	6.6E-12	8.9E-13	17,245
Naphthalene	91-20-3	$C_{10}H_8$	6200	3200	SVOC		128	218	6.3E-02	8.3E-03	16,720
Toluene	108-88-3	C_7H_8	69000	36000	VOC	0.87	92	111	2.8E+01	3.7E+00	18,279
Oxygenates											
Acetophenone	98-86-2	C_8H_8O	ND	2400	SVOC	1.03	120	202	4.0E-01	5.3E-02	14,872
Acrolein	107-02-8	C_3H_4O	ND	39	VOC	0.84	56	53	2.8E+02	3.7E+01	12,500
Allyl alcohol	107-18-6	C_3H_6O	ND	30	VOC	0.85	58	97	2.5E+01	3.3E+00	13,746
Bis(2-ethylhexyl)phthalate [Di-2ethylhexyl phthalate]	117-81-7	$C_{24}H_{38}O_4$	ND	2400	SVOC	0.99	391	387	1.7E-01	2.2E-02	15,130
Butyl benzyl phthalate	85-68-7	$C_{19}H_{20}O_4$	ND	2400	SVOC	1.12	312	370	1.2E-05	1.6E-06	14,550
o-Cresol [2-Methyl phenol]	95-48-7	C_7H_8O	ND	2400	SVOC	1.04	108	191	2.5E-01	3.3E-02	15,013
m-Cresol [3-Methyl phenol]	108-39-4	C_7H_8O	ND	2400	SVOC	1.03	108	202	1.5E-01	2.0E-02	14,752
p-Cresol [4-Methyl phenol]	106-44-5	C_7H_8O	ND	2400	SVOC	1.02	108	202	1.1E-01	1.5E-02	15,025
Di-n-butyl phthalate	84-74-2	$C_{16}H_{22}O_4$	ND	2400	SVOC	1.05	278	340	8.0E-03	1.1E-03	13,300
Diethyl phthalate	84-66-2	$C_{12}H_{14}O_4$	ND	2400	SVOC	1.12	222	298	1.7E-03	2.2E-04	10,920
2,4-Dimethylphenol	105-67-9	$C_8H_{10}O$	ND	2400	SVOC	0.97	122	211	1.3E-01	1.7E-02	15,330
Dimethyl phthalate	131-11-3	$C_{10}H_{10}O_4$	ND	2400	SVOC	1.19	194	284	1.0E-02	1.3E-03	10,428
Di-n-octyl phthalate	117-84-0	$C_{24}H_{38}O_4$	ND	2400	SVOC	0.99	391	220	3.3E-02	4.4E-03	15,258
Endothall	145-73-3	$C_8H_{10}O_5$	ND	100	SVOC	1.43	186	200	1.8E-04	2.4E-05	7,500
Ethyl methacrylate	97-63-2	$C_6H_{10}O_2$	ND	39	VOC	0.91	114	117	1.7E+01	2.3E+00	12,670
2-Ethoxyethanol [Ethylene glycol monoethyl ether]	110-80-5	$C_4H_{10}O_2$	ND	100	SVOC	0.03	90	135.6	4.6E+00	6.2E-01	11,877
Isobutyl alcohol	78-83-1	$C_4H_{10}O$	ND	39	VOC	0.80	74	108	1.0E+01	1.3E+00	15,498
Isosafrole	120-58-1	$C_{10}H_{10}O_2$	ND	2400	SVOC	1.12	162	253	2.4E-01	3.2E-02	13,710
Methyl ethyl ketone [2-Butanone]	78-93-3	C_4H_8O	ND	39	VOC	0.81	72	80	9.1E+01	1.2E+01	13,480
Methyl methacrylate	80-62-6	$C_5H_8O_2$	ND	39	VOC	0.94	100	100	3.6E+01	4.8E+00	11,400
1,4-Naphthoquinone	130-15-4	$C_{10}H_6O_2$	ND	2400	SVOC	1.42	158	121 ^{Subl}	9.8E-03	1.3E-03	12,607
Phenol	108-95-2	C_6H_6O	ND	2400	SVOC	1.07	94	182	3.5E-01	4.7E-02	13,973
Propargyl alcohol [2-Propyne-1-ol]	107-19-7	C_3H_3OH	ND	30	VOC	0.96	56	114	1.5E+01	1.9E+00	11,551
Safrole	94-59-7	$C_{10}H_{10}O_2$	ND	2400	SVOC	1.09	162	232	3.9E-01	5.2E-02	13,824
References for Physical Properties											
www.chemfinder.com											
http://wwwniehs.nih.gov (National institute of Health)											
www.osha.gov											
CRC Handbook of Chemistry & Physics											
A.D. Little, 1983, "Sampling & Analytical Methods for HWCs"											

Table 2-1: Current Comparable Fuels Specification Limits and Properties of Oxygenates and Hydrocarbons.

Volatility: The table shows the classification of the constituents between VOC and SVOC.[15] As discussed below VOCs have lower boiling points and higher vapor pressures when compared to SVOCs. Two hydrocarbons (benzene & toluene) as well as seven oxygenates (acrolein, allyl alcohol, ethyl methacrylate, methyl methacrylate, isobutyl alcohol, methyl ethyl ketone, and propargyl alcohol) are classified as VOCs.

Boiling Point: The boiling points of the 37 compounds range from 53-117°C for VOCs and 136 – 536°C for SVOC. Acrolein has the lowest boiling point while indeno pyrene has the highest.

Vapor Pressure: Values for vapor pressure were extracted from various references as shown in the table.[16] The values range from 1.3 to 37 kPa for VOC with acrolein having the highest vapor pressure. For SVOC, the range is from 0.62 kPa to as low as 8.9×10^{-13} kPa.

Heating Value: Table 2-1 also shows the higher heating value (HHV) or gross heat of combustion for the 37 constituents. These values were tabulated from several references as shown in the table. For seven compounds tabulated data were not readily available and heating values were estimated using the Dulong formula which estimates heating value from composition of the substance.

$$\text{HHV (Btu/lb)} = 14{,}544 * \text{C} + 62{,}028 * [\text{H} - (\text{O}/8)] + 4{,}050 * \text{S}$$

With the exception of one compound, the heating values of the hydrocarbons and oxygenates fall in the range 10,000 to18,500 Btu/lb.[17]

2.3 Incinerability Index

The incinerability index, a metric developed by researchers at University of Dayton Research Institute (UDRI) and EPA's Risk Reduction Engineering Laboratory (RREL), categorizes all 40 CFR 261, App VIII toxic organic compounds into seven thermal stability classes[18]. Additionally, each compound is ranked from 1 to 320 based on the temperature required to achieve 99% destruction in two seconds under low oxygen conditions. The index was developed to aid selection of principle organic hazardous constituents (POHC) for trial burn testing to demonstrate compliance with the RCRA destruction and removal efficiency (DRE) standard and was derived using a combination of theoretical and experimental data.

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[15] This classification is based on the test methods used to measure the constituent during the development of the specifications.

[16] In a few instances the vapor pressure values were available temperatures other than 25 C and were corrected to 25 °C assuming that vapor pressure varies linearly with temperature.

[17] The one exception was endothall which had an estimated heating value of 7500 Btu/lb.

[18] Dellinger B., & Talor P.H., " Designating Principal Organic Hazardous Constituents," App D in USEPA "Guidance on Setting Permit Conditions and Reporting Trial Burn Results, 1989, EPA/625/6-89/019

The destruction of an organic compound is a function of temperature, residence time at the temperature, and compound specific properties.[19] A simplified approach is to treat the destruction of a POHC using first order kinetic considerations. The rate of destruction of a POHC is given by,

$$dC/dt = -kC \text{ ------- } (2.3.1)$$

where, C is the concentration of the POHC, t is time, and k is the reaction rate constant that is a function of temperature and is given by the Arrhenius equation

$$k = Ae^{-E/RT} \text{ ---- } (2.3.2)$$

where:
A= frequency factor (units of s^{-1}),
E= Activation energy (units of cal/gmol),
R = universal gas constant (1.987 cal/gmol.K), and
T = Temperature (K)

Here A and E are a function of the POHC and also depends on if POHC destruction occurs under fuel-lean or fuel rich conditions.

Substituting for k in equation (2.3.1) and integrating one gets concentration at time t

$$C(t) = C_o * \exp\left\{-At * \exp\left(-E/RT\right)\right\} \text{ ----------------------- } (2.3.3)$$

Where C_o is the inlet POHC concentration.

Re-arranging equation (2.3.3) in terms of temperature and using destruction removal efficiency (DRE) = $(C_o\text{-}C)/C_o$ = $1\text{-}C/C_o$, we get,

$$T = \frac{E}{R * \ln\left[\frac{-tA}{\ln(1-DRE)}\right]} \text{ ---------------------- } (2.3.4)$$

Therefore, if A and E are known, and if elapsed time and DRE are specified, the temperature required to achieve a given DRE within a given time can be calculated. Table 2-2 lists the incinerability ranking, thermal stability class, and $T_{99}(2)$ values for oxygenates and hydrocarbons.[20] One can see from the table that 10 of 13 hydrocarbons are in Class 1 in terms of thermal stability which means they are the most difficult to destroy. In fact, benzene and napthalene have the third and fourth highest $T_{99}(2)$ values

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[19] Brunner, C.R., 1988 “Handbook of Hazardous Waste Incineration”, TAB Books

[20] $T_{99}(2)$This is the temperature required to achieve 99% DRE in two seconds. Note-The compound with the highest $T_{99}(2)$ values is ranked #1 and so on.

respectively. On the other hand, oxygenates are in lower thermal stability classes and are in general easier to destroy in comparison to hydrocarbons.

Chemical Name	CAS #	Incin Index Class	Incinerability Rank	T_{99}(2) (°C)
Hydrocarbons:				
Benzo(a)anthracene	56-55-3	1	7--11	1060
Benzene	71-43-2	1	3	1150
Benzo(b)fluoranthene	205-99-2	1	7--11	1060
Benzo(k)flouranthene	207-08-9	1	7--11	1062
Benzo(a)pyrene	50-32-8	1	12	1025
Chrysene	218-01-9	1	7--11	1060
Dibenzo(a,h)anthracene	53-70-3	1	13-16	1020
Dimethylbenz(a)anthracene	57-97-6	2	49	855
Fluoroanthene	206-44-0	1	6	1062
Indeno(1,2,3,cd)pyrene	193-39-5	1	7--11	1060
3-Metylcholanthrene	56-49-5	2	66	805
Naphthalene	91-20-3	1	4	1090
Toluene	108-88-3	2	38	895
Oxygenates:				
Acetophenone	98-86-2	3	86--90	775
Acrolein	107-02-8	4	139-142	670
Allyl Alcohol	107-18-6	4	143	665
Bis(2-etylhexyl)phthalate	117-81-7	8	290-291	370
Butylbenzyl phthalte	85-68-7	5	273	415
o-Cresol(2-mehyl phenol)	95-48-7	3	116	746
m-Cresol(3-mehyl phenol)	108-39-4	3	115	749
p-Cresol(4-mehyl phenol)	106-44-5	3	117	745
Di-n-butyl phthalate	84-74-2	6	282-286	390
Di ethyl pthalate	84-66-2	5	276-277	400
2-4 Dimethyl phenol	105-67-9	3	128	700
Di methyl phthalate	131-11-3	3	94--99	765
Di-n-octyl phthalate	117-84-0	6	288	380
Endothall *	145-73-3			
Ethyl Methacrylate	97-63-2	5	314-217	584
2-Ethoxy ethanol *	110-80-5			
Isobutyl Alcohol	78-83-1	3	122	715
Isosafrole	120-58-1	5	266-269	460
Methyl ethl ketone	78-93-3	3	119-120	730
Methyl methacrylate	80-82-6	2	61-62	820
1,4 Naphthoquinone	130-15-4	3	94--99	765
Phenol	108-95-2	3	86-90	775
Propargyl Alcohol	107-19-7	5	226-228	560
Safrole	94-59-7	5	266-269	460

[*] Incinerability index rankings are not available for these compounds

Table 2-2: Incinerability Rank and Thermal Stability Class for Oxygenates and Hydrocarbons

2.4 Relative Hazard Categorization Scheme

We assessed the relative hazard of the 37 constituents in Table 1 to §261.38 using a stepped approach, including: (1) ranking 37 chemicals using the Waste Minimization Prioritization Tool (WMPT); (2) subdividing ranked chemicals into categories; and (3) assigning “worst case” subscores to constituents with insufficient data to generate WMPT scores.

2.4.1 Step 1: Ranking Chemicals Using MWPT

In the first step of our three-step process, we used the WMPT (U.S. EPA, 2000) to rank the 37 hydrocarbons and oxygenates according to their relative hazard. The WMPT was attractive and appropriate because it had been so thoroughly reviewed, and used in previous RCRA decision-making (see the side-bar regarding the PBT Chemical list development). The WMPT is a joint product of EPA’s Office of Solid Waste (OSW) and EPA’s Office of Pollution Prevention and Toxics (OPPT). It provides a screening-level assessment of potential chronic (i.e., long-term) risks to human health and the environment. The relative chemical rankings derived from the WMPT can complement other risk or cost information in the decision-making process.

The purpose of the WMPT scoring method is to develop chemical-specific scores for a screening-level risk-based ranking of chemicals. The scoring method was designed to generate an overall chemical score that reflects the potential of a chemical to pose risk to either human health or ecological systems. A measure of human health concern is derived, consistent with the risk assessment paradigm, by jointly assessing the chemical’s human toxicity and potential for exposure. Similarly, a measure of the ecological concern is derived by jointly assessing the chemical’s ecological toxicity and potential for exposure.

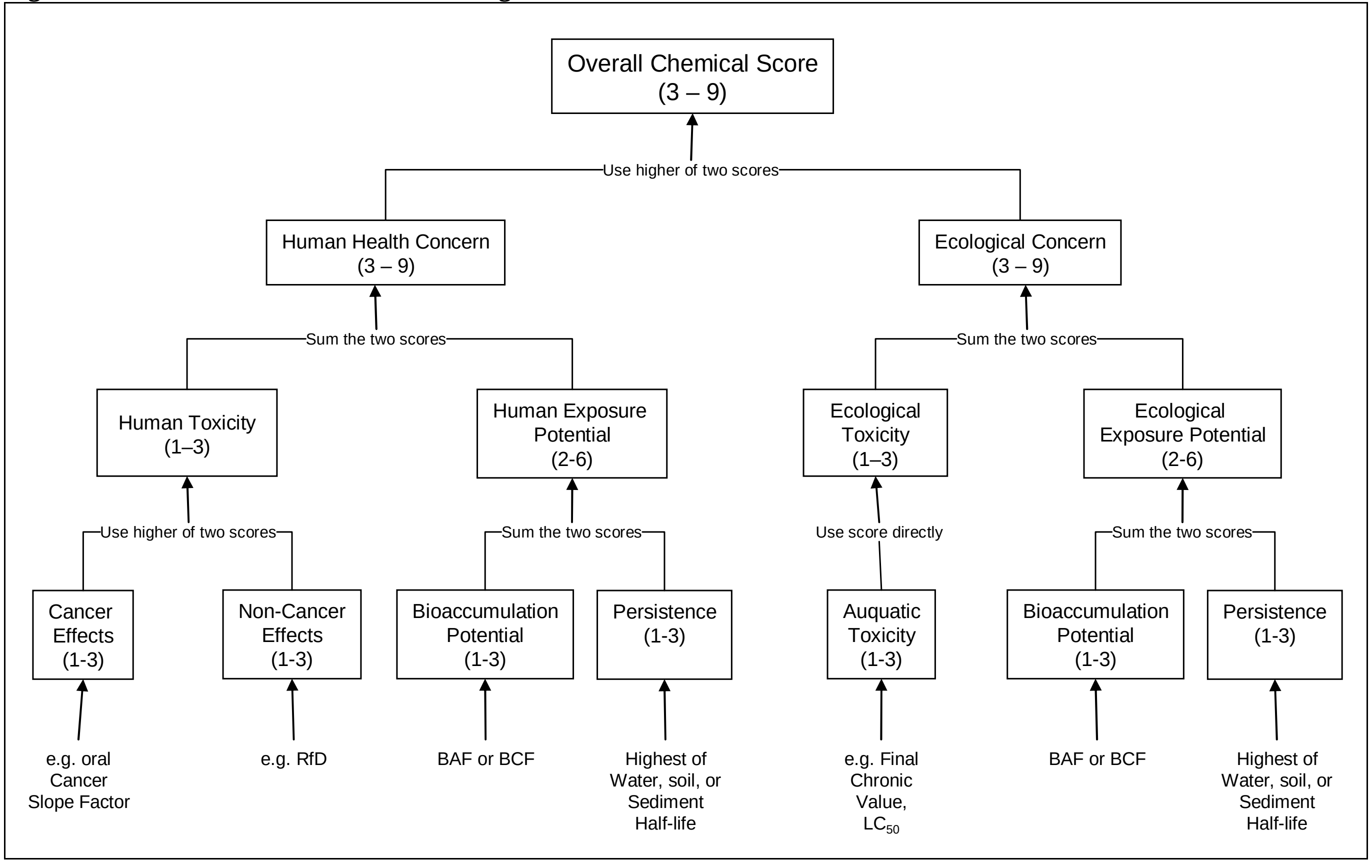
The WMPT’s scoring method is modeled after the general risk calculation equation used by U.S. EPA and others, where the risk of a chemical is derived by combining estimates of the toxicity of the chemical with estimates of the actual or potential exposure to the chemical. The WMPT uses a small number of relatively simple measures to represent the toxicity (e.g. oral Cancer Slope Factor) and exposure potential (e.g. Bioaccumulation Factor) of each chemical, consistent with a screening-level approach and with other systems of this type. Figure 2-1 graphically represents examples of the various measures, and how they culminate in WMPT scores. A detailed list of the measures is available in USEPA (2000).

EPA’s Priority Chemical List

After several rounds of internal expert and public comments, EPA used the current version of the WMPT as the initial step in the process of identifying the initial pool of persistent, bioaccumulative, and toxic chemicals that are national priorities for voluntary pollution prevention activities across the agency. EPA determined the initial pool of priority chemical candidates based on their rank. The rankings are based on the higher of available scores for human health concern (i.e., the sum of the scores for persistence, bioaccumulation, and human toxicity) and ecological concern (i.e., the sum of the scores for persistence, bioaccumulation, and ecological toxicity). The priority chemical candidate pool was limited to those chemicals with WMPT scores of 8 or 9 (on a scale of 3 to 9).

See USEPA (2000) for a more detailed description of the WMPT development process. The specific use of the current version of the WMPT rankings in developing the RCRA priority chemical list is documented in the Tier III Priority Chemical List Docket.

Figure 2-1: Overview of the WMPT Scoring Method



The Human Health Concern score is derived by adding two factor-level scores, one reflecting the toxicity of the chemical to humans and the other the potential for exposure to the chemical. The Human Toxicity score is derived by taking the higher of two "subfactor" scores: (1) Cancer Effects, and (2) Noncancer Effects. The Human Exposure Potential score is derived as the sum of two subfactor scores: (1) Persistence and (2) Bioaccumulation Potential. Similar to the Human Health Concern score, the Ecological Concern score is derived by adding two factor-level scores, one reflecting the toxicity of the chemical to aquatic ecosystems and the other the potential for exposure to the chemical.

Scores are first generated at the subfactor level. A score for a given subfactor is derived by evaluating certain chemical-specific parameters that represent that subfactor. Each chemical-specific parameter is assigned a score depending on the level of concern associated with the chemical's tendency to demonstrate the characteristic (see the side-bar regarding the fenceline approach to scoring). These scores are then "aggregated upward" to generate an overall chemical score.

The parameters used to score the various subfactors are briefly described below:

- Persistence – measured or estimated half-life in water, soil, or sediment;
- Bioaccumulation Potential – measured or estimated Bioaccumulation Factors (BAFs) or Bioconcentration Factors (BCFs);
- Human Toxicity – Cancer Slope Factors and non-cancer Reference Doses;
- Ecological Toxicity – a number of data elements representing measured or estimated chronic and acute aquatic toxicity extracted from a number of U.S. EPA sources (e.g., Final Chronic Values, measured and estimated aquatic chronic values, EC50s, LC50s, and aquatic toxicity reportable quantities).

The Fenceline Approach

Most of the subfactors are scored using a "fenceline" approach. The fenceline scoring approach involves comparing the value for a given chemical data element against predefined "high" and "low" threshold values for that data element, termed "fencelines."

For some data elements, lower numeric values denote higher concern. For example, the more toxic chemicals are represented by lower numerical values for Reference Doses (RfDs). Thus, if the chemical-specific value for the given data element is greater than the "low" fenceline, the subfactor is assigned a score of 1 (low concern). If the chemical-specific value is less than the "high" fenceline, the subfactor is assigned a score of 3 (high concern). If the chemical's value for that data element is between the "high" and the "low" fencelines, the subfactor is assigned a score of 2 (medium concern). For other data elements (e.g., the cancer potency slope factor, BCFs), lower numeric values denote lower concern; in such cases, the fenceline logic is reversed. All the subfactors are scored as low concern (score = 1), medium concern (score = 2), or high concern (score = 3).

U.S. EPA (2000) provides more detailed descriptions of the types of data used, as well as the hierarchies of data sources.

2.4.1.1 Ranking Poly-Aromatic Hydrocarbons (PAHs) as a Category

For the Priority Chemical List effort, the WMPT collected chemical-specific data element values, and assigned sub-factor and factor scores for all constituents. However, to be consistent with the TRI, which combines individual PAH compounds into a single

PAH category, the WMPT also created a PAH category, and assigned a single final ranking score to the entire category, rather than rank each PAH individually. The PAH category was assigned a WMPT score based on the highest scoring PAH in the category. To be consistent with the WMPT methodology, we also collected chemical-specific data and scored each constituent separately, but ranked the category as a whole rather than ranking individual PAHs. To make sure we used the most inclusive and up-to-date definition of the PAH category for this effort, we used the U.S. EPA (2001) list of PAHs. The comparable fuel hydrocarbons which qualify as PAHs according to USEPA (2001) include the following:

TABLE 2-3: Comp Fuels Hydrocarbons that Are PAHs

Chemical	CAS#
3-Methylcholanthrene	56-49-5
7,12-Dimethylbenz(a)anthracene	57-97-6
Benzo(a)anthracene	56-55-3
Benzo(a)pyrene	50-32-8
Benzo(b)fluoranthene	205-99-2
Benzo(k)fluoranthene	207-08-9
Chrysene	218-01-9
Dibenzo(a,h)anthracene	53-70-3
Fluoranthene	206-44-0
Indeno(1,2,3-cd)pyrene	193-39-5

2.4.1.2 Updating/Collecting Constituent-Specific Data

Some, but not all of the 37 hydrocarbons and oxygenates were assessed for the Priority Chemical List. For those chemicals that had been ranked, we updated the chemical-specific values where appropriate (e.g. if the original source had been updated since the PBT list was generated) and re-evaluated each chemical, to see if their WMPT scores changed with more up-to-date data.

For those hydrocarbons and oxygenates that hadn't been assessed, we collected data from the same hierarchy of sources as the WMPT, and used the WMPT methodology to score each chemical. Table 2-4 summarizes sub-factor and factor scores. A detailed list of parameter values (including sources) which led to the scores is available in Appendix I.

2.4.2 Step 2: Subdividing the Ranked Constituents into Categories

As stated above, the WMPT is a screening tool. Screening tools are often used as one step in multi-step evaluations, in which later steps further refine the analysis. In the current effort, we used the WMPT as the first step in a three-step evaluation. Step two applied a series of filter criteria to categorize the constituents according to their relative hazard.

Phase 1 (Chemicals with a WMPT score of 8 or 9): As the first step in its Priority Chemical List methodology, the Agency identified for further study those chemicals which received a WMPT Overall Chemical Score of 8 or 9[21]. Consistent with the approach the Agency used to identify chemicals for the Priority Chemical List, we consider chemicals that have a WMPT score of 8 or 9 to be high hazard chemicals.

Any chemicals satisfying this criterion were assigned to Category A. All remaining chemicals continued to Phase 2.

Next, we considered whether any of the remaining constituents, those that did not receive a WMPT score of 8 or 9, present additional concerns for materials managed as comparable fuels. We did this by further analyzing the data that WMPT used to generate Human Toxicity scores for the remaining constituents. We first identified constituents that had WMPT Human Toxicity scores based on inhalation as the driving exposure pathway[22]. This is an appropriate screening criterion given that the inhalation pathway is particularly important for evaluating the hazard posed by air emissions. For such constituents, we then determined whether they posed a relatively high human toxicity hazard or were a known human carcinogen.

<u>Phase 2a</u> (Chemicals with a WMPT Human Toxicity score based on inhalation toxicity): Chemicals satisfying this criterion continued to Phase 2b. All other chemicals were assigned to Category C.

<u>Phase 2b</u> (Chemicals with a High WMPT Human Toxicity score i.e., a score of 3, OR that USEPA/IRIS has designated a "known human carcinogen"): The Agency considers it pertinent to consider the relative magnitude of inhalation toxicity when assessing the potential hazard of a substance.

Also, the WMPT scoring methodology is such that a chemical's Human Toxicity score is based on a single, exposure pathway-specific health benchmark (see Footnote 22). The Human Toxicity scores for the non-Category A chemicals were all based on non-cancer toxicity – including, therefore, any subset of chemicals satisfying the Phase 2a criterion. Yet pertinent cancer-related information may exist that's not captured in the Human Toxicity score. We therefore took note of any chemicals with sufficient weight-of-evidence (WOE) associated with their cancer potency that the EPA/IRIS program not only generated a carcinogenic slope factor, but also designated them "known human carcinogens" (notated as "WOE Class A" in the WMPT).

All chemicals satisfying the Phase 2a criterion *and* found to be *either* a known human carcinogen *or* to have a high WMPT toxicity subscore, (i.e., a score of 3) were assigned to Category B. All other chemicals were assigned to Category C.

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[21] The specific use of the current version of the WMPT rankings in developing the RCRA Priority Chemical List is documented in the Tier III Priority Chemical List Docket.

[22] The human toxicity score is based on one of a variety of data elements representing human Toxicity (e.g., Cancer Slope Factor, or inhalation Reference Concentration). The appropriate value was compared to the WMPT scoring fencelines (see "The Fenceline Approach " above) for that particular data element. If several data elements were available, the highest of the scores based on these data was taken as the chemical score. See USEPA (2000) for a more detailed explanation of how WMPT Human Toxicity scores were generated.

2.4.3 Step 3: Chemicals with Insufficient Data to Generate WMPT Scores

The final Step in the evaluation assessed the potential impacts of insufficient data on chemical ranking. There were five chemicals (1,4-napthoquinone, isosafrole, propargyl alcohol, safrole, di methyl phthalate) with insufficient data to develop a WMPT score. The Agency assigned these substances a worst-case Human Toxicity subscore of 3, to determine if any chemical might qualify for either Category A or B.

2.4.4 Outcome

Table 2-4 lists the scores and final WMPT ranking of the 37 chemicals. Some subfactor scores for re-evaluated chemicals did change (e.g. Phenol's Human Toxicity score changed from 1 to 2), but these changes never led to a change in a final WMPT score.

To make reading the table more intuitive, we sorted the list as follows:

1. Whether the constituent is a PAH according to the U.S. EPA (2001) definition;
2. Category;
3. By Concern score (descending); and
4. Alphabetically.

Because the entire PAH category was assigned the final score of the highest scored constituent (see "Ranking PAHs as a Category" above), all PAHs qualified for Category A, regardless of their constituent-specific Higher Concern score. Naphthalene was the only other constituent to qualify for Category A.

Benzene, acrolein, and phenol have WMPT toxicity scores based on inhalation toxicity, satisfying the Phase 2a criterion. USEPA/IRIS classifies benzene as a "known human carcinogen" (USEPA 2006), satisfying the Phase 2b criterion[23]. Acrolein's very high inhalation toxicity qualified it for a High Human Toxicity score (i.e., 3) in WMPT, satisfying the Phase 2b criterion. Phenol, however, is not classified a known human carcinogen, and has only a Medium WMPT Human Toxicity Score (i.e., 2). Therefore, phenol did not satisfy either Phase 2b criterion, and was assigned to Category C.

The remaining constituents were assigned to Category C.

As detailed in Table 2-4, the distribution of Persistence Factor and Bioaccumulation Factor scores for the remaining constituents was such that a high Ecological Toxicity score would not have elevated any of the constituents to a different Category. We therefore did not collect any additional ecological toxicity data.

Also, the distribution of Persistence Factor and Bioaccumulation Factor scores for the remaining constituents was such that none of the five chemicals without WMPT scores (see Section 1.1.3 above) would have qualified for either Category A or B.

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[23] Benzene also has a High WMPT Eco-toxicity score, is a PAH precursor, and very difficult to destroy thermally. This information suggests that benzene warrants special consideration in current decision-making.

REFERENCES for Section 2.4:

U.S.EPA 2000. *Waste Minimization Prioritization Tool Background Document for the Tier III PBT Chemical List*.

U.S. EPA 2001. *Emergency Planning and Community Right-to-Know Act (EPCRA) - SECTION 313: Guidance for Reporting Toxic Chemicals: Polycyclic Aromatic Compounds Category*. Office of Environmental Information. EPA 260-B-01-03. August.

U.S. EPA 2005. *Human Health Risk assessment Protocol for Hazardous Waste Incineration Facilities*. Office of Solid Waste. EPA-R-05-006. September.

U.S. EPA 2006. *Integrated Risk Information System (IRIS): Benzene*. http://www.epa.gov/iris/ . Accessed September 2006.

TABLE 2-4: WMPT Scoring and Ranking, and Categorization of Comparable Fuels Hydrocarbons and Oxygenates

Chemical Name	CASRN	EPCRA 313 PAH?	Persistence Score	Bioaccumulation Score	Human Toxicity Score	Ecological Toxicity Score	Human Concern Score	Ecological Concern Score	Higher Concern Score	CATEGORY
			(P)	(B)	(HT)	(ET)	(P+B+HT)	(P+B+ET)		
3-Methylcholanthrene	56495	X	3	3	3	3	9	9	9	A
7,12-Dimethylbenz(a)anthracene	57976	X	3	3	3	3	9	9	9	A
Benzo(b)fluoranthene	205992	X	3	3	2	3	8	9	9	A
Benzo(k)fluoranthene	207089	X	3	3	2	3	8	9	9	A
Dibenzo(a,h)anthracene	53703	X	3	3	3	3	9	9	9	A
Indeno(1,2,3-cd)pyrene	193395	X	3	3	1	3	7	9	9	A
Benzo(a)pyrene	50328	X	3	2	3	3	8	8	8	A
Fluoranthene	206440	X	3	2	2	3	7	8	8	A
Benzo(a)anthracene	56553	X	3	1	2	3	6	7	7	A
Chrysene	218019	X	3	1		3		7	7	A
Naphthalene	91203		3	2	2	3	7	8	8	A
Benzene	71432		3	1	2	3	6	7	7	B
Acrolein	107028		2	1	3	3	6	6	6	B
Bis(2-ethyhexyl)phthalate	117817		3	2	2	1	7	6	7	C
Dibutyl phthalate	84742		1	2	1	3	4	6	6	C
Diethyl phthalate	84662		3	1	1	2	5	6	6	C
2-Ethoxy ethanol	110-80-5		2	1	2		5		5	C
Allyl alcohol	107186		1	1	2	3	4	5	5	C
Butyl benzyl phthalate	85687		1	1	1	3	3	5	5	C
Di-n-octyl phthalate	117840		1	2	2	0	5	3	5	C
Endothall	145-73-3		2	1	2		5		5	C
Toluene	108-88-3		3	1	1		5		5	C
2,4-Dimethylphenol	105679		1	1	2	2	4	4	4	C
Acetophenone	98-86-2		2	1	1		4		4	C
Cresol, o-	95487		1	1	2	2	4	4	4	C
Ethyl Methacrylate	97-63-2		2	1	1		4		4	C
Isobutyl alcohol	78831		1	1	1	2	3	4	4	C
m-Cresol(3-methyl phenol)	108-39-4		1	1	2		4		4	C
Methyl methacrylate	80-62-6		2	1	1		4		4	C
p-Cresol(4-methyl phenol)	106-44-5		1	1	2		4		4	C
Phenol	108952		1	1	2	2	4	4	4	C
Methyl ethyl ketone	78-93-3		1	1	1		3		3	C
1,4 Naphthoquinone	130-15-4		3	1	ND		ID (7?)			C
Isosafrole	120-58-1		2	1	ND		ID (6?)			C
Propargyl Alcohol	107-19-7		2	1	ND		ID (6?)			C
Safrole	94-59-7		2	1	ND		ID (6?)			C
Di methyl phthalate	131-11-3		1	1	ND		ID (5?)			C
ND = No Data										
ID = Insufficient Data to classify (maximum possible)										
dotted = PAH's										
gray = not in original WMPT effort										

2.5 Restrictions on High Hazard Compounds

Based on the hazard category rankings discussed in the previous sections, the following restrictions are proposed.

- The current comparable fuels specifications are retained for hazard category A compounds: naphthalene and ten other hydrocarbon compounds that are classified as PAHs. Note that this category includes all comparable fuels hydrocarbons (with the exception of benzene) that are in class 1 of the thermal stability ranking.
- For hazard category B compounds (benzene and acrolein), there are additional firing rate restrictions (beyond what is discussed in section 1.3). If the ECF contains more than 2% by mass of benzene or 2% by mass of acrolein, the firing rate of ECF will be restricted to 25% on a volume or heat input basis whichever results in a lower volume of ECF. The 2% cutoff level was selected so the limit on benzene and acrolein would be no more stringent than their corresponding limits for current comparable fuels.

3 Industrial Boilers

This section summarizes industrial boiler designs and fuels used in industrial, commercial, and institutional boilers. Although various types of boiler designs and fuels are discussed in this section, it should be noted that ECF combustion would only be allowed in industrial (or utility), nonstoker, watertube steam boilers that fire fossil fuel as the primary fuel.

Boilers burning ECF must meet the RCRA definition of boilers codified in 40 CFR 260.10. A boiler is defined as an enclosed device using controlled flame combustion with the following characteristics:

- The combustion chamber and energy recovery section must be of integral design.
- Thermal recovery efficiency must be greater than 60%, determined as the ratio of the recovered energy to the thermal value of the fuel.
- Greater than 75% of the recovered energy must be exported and used (i.e., this does not include internal boiler uses such as preheating combustion air or driving combustion air fan or feedrate pumps).

In September 2004, EPA promulgated national emissions standards for hazardous air pollutants (NESHAP) for industrial, commercial and institutional (ICI) boilers.[24] The inventory database for this rule contains more 58,000 ICI boilers and process heaters. Industrial boilers are used in all major industrial sectors but primarily by the paper products, chemical, food and petroleum industries.[25] Industrial boilers typically range in size from 10 to 250 MMBtu/hr, although larger units do exist. Commercial/institutional boilers supply steam or hot water in hospitals, schools, hotels, restaurants etc. and are usually smaller than 10 MMBtu/hr.

3.1 Fuels

ICI boilers use a myriad of solid, liquid and gaseous fuel types from fossil fuels (such as natural gas, fuel oil, coal) to non-fossil fuels such as wood, tires, industrial sludge, baggasse, and municipal waste. Some of these fuels are discussed below.

3.1.1 Fuel Oil

Approximately 10% of all ICI boilers burn fuel oil.[26] The term fuel oil can refer to any product derived from petroleum that has volatility lower than that of gasoline. The ASTM D396-2(a) specification divides fuel oil into several classes, from fuel oil No.1 to fuel oil No. 6, based on boiling range, composition, and other physical properties. As the

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[24] See 69 FR 55218.

[25] USEPA, 2004, "Regulatory Impact Analysis for the Industrial Boiler & Process Heater NESHAP," EPA-452/R-04-002

[26] Six thousand out of 57,000 ICI boilers and process heaters are oil-fired units according to, USEPA, "The Upcoming Industrial Boiler & Process Heater MACT Standard., "A&WMA MACT Web Confierence, May 2002.

fuel oil number increases, the number of carbon atoms increases from about 9 to about 70, the boiling range and viscosity also increase. Additionally, the value of fuel oil decreases with from No.1 to No.6. Fuel oils are generally classified as either distillate or residual based on whether or not they are vaporized in normal refining operations. Usually, fuel oils No. 1 and 2 are distillate fuels, No. 5 and No. 6 fuel oils are residual fuels, and No.4 is a blend of distillate and residual fuels.[27]

Table 3-1 shows typical properties of various classes of fuel oil such as flash point, specific gravity, API gravity, heating value, and kinematic viscosity.[28] The flash point is the temperature to which the liquid must be heated to produce vapors that flash but do not burn continuously.

Grade of Fuel Oil	**Flash Point** (°C)	**Specific Gravity**	**API Gravity**	**Heating Value** (Btu/lb)	**Kinematic Viscosity**[1] (cS)
1	38	0.806 - 0.825	40 - 44	19800	1.4 - 2.2
2	38	0.825 - 0.887	28 - 40	19500	2.0 - 3.6
4	55	0.876 - 0.966	15 - 30	18800	6 - 27
5	55	0.922 - 0.972	14 - 22	18600	30 -160
6	65	0.922 - 1.022	7 - 22	18200	90 - 640*

[1] Viscosity values are at 50 °C for fuel oil No.6 and at 38°C for the others

Table 3-1: Properties of Fuel Oils

API gravity is calculated by:

$$API\ Gravity = \frac{141.5}{specific\ gravity @ 60F} - 131.5$$

Fuel oil heating values range from 18,000 to 20,000 Btu/lb or 130,000 to 150,000 Btu/gal. As the table shows, the residual fuels are extremely viscous and must be heated in order to be transported and atomized in a burner.

Note that diesel has similar specifications to fuel oil No.2 and contains hydrocarbons with boiling points in the range 175 – 380 °C.[29]

<u>Gasoline</u>: Although gasoline is not used in industrial boilers, gasoline was used as a benchmark fuel to establish the comparable fuel specification because it provides a reasonable upper boundary for volatile organics which are fuel-worthy constituents.[30] Table 3-2 outlines the ASTM D4814 specifications for gasoline with regards to vapor pressure (@38 °C) and distillation temperature for six volatility classes.[31,32] The table

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[27] USEPA, "AP 42:Compilation of Air Pollution Emissions Factors, Vol I: Stationary Point and Area Sources," , 5th Edition, 1995, Ch.1.3 Fuel Oil Combustion.

[28] Property values from, Stultz & Kitto, eds, "Steam: It's Generation and Use," 40th Edition, 1992, Ch.8.

[29] Chevron Products Company, "Diesel Fuels Technical Review," 1998

[30] See preamble to the 1998 comparable fuels rulemaking at 63 FR 33785.

[31] Various geographic regions in the are assigned single volatility class each month based on altitude and ambient temperature range

shows a distillation profile for each volatility class. (For example for class AA at least 10% of the fuel must evaporate at 70°C, 90% at 190 °C and 100% at 225 °C).

Volatility Class	Max VP mm Hg	Max Distillation Temperature (°C)		
		10% evap	90% evap	end point
AA	403	70	190	225
A	465	70	190	225
B	517	65	190	225
C	595	60	185	225
D	698	55	185	225
E	776	50	185	225

Table 3-2: Gasoline Specifications

These specifications generally indicate that gasoline constituents must have a boiling point no higher than 225 °C and not much lower than 50°C and vapor pressures no higher than 776 mm Hg.

The Agency for Toxic Substances and Disease Registry (ATSDR) has developed a toxilogical profile for gasoline.[33] The ASTDR report says that gasoline contains more than 150 chemicals and the actual content of specific organics is a function of the source of crude, the manufacturer and the time of year. The primary components of gasoline are aliphatic hydrocarbons (in particular straight chain and branched alkanes) and aromatic hydrocarbons from carbon numbers C_4 to C_{12}.

Oxygenates: Oxygenates have been added to gasoline starting with ethanol in the 1970's. The introduction of CAA requirements to use reformulated gasoline (RFG) in ozone non-attainment areas starting in the 1990's increased the use of oxygenates in gasoline. RFG is blended gasoline that is cleaner burning than conventional gasoline. One requirement for RFG is oxygen content.[34] A survey conducted by an association of blenders, refiners, and importers of gasoline, and shown on the EPA office of transportation and air quality's (OTAQ) website, indicates that in 2003 RFG had an average oxygen content of 2.15-2.3%.[35] Alcohols and ethers are typically used as oxygenates with ethanol, methyl tertiary butyl ether (MTBE),[36] and tertiary-amyl methyl ether (TAME) being the most widely used oxygenates in the US.[37] However, in Europe the EN 228 specifications permit several oxygenates at various concentrations including isobutyl alcohol at 10%.

Additionally, oxygenates have also been added to diesel fuel to improve combustion and lower emissions. E diesel, a blend of diesel with up to 15% ethanol is an experimental fuel being demonstrated in trucks, buses, and farm machinery.[38] Many

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[32] From http://www.faqs.org/faqs/autos/gasoline-faq/

[33] ASTDR, 1995, "Toxicological Profile for Automotive Gasoline," http://www.atsdr.cdc.gov/toxprofiles/tp72.html

[34] This requirement is currently being removed. http://www.epa.gov/OMS/rfg.htm

[35] http://www.epa.gov/OMS/regs/fuels/rfg/properf/rfg-params.htm

[36] The use of MTBE is being phased out.

[37] Chevron Products Co., "Motor Gasoline Technical Review", 1996

[38] http://www1.eere.energy.gov/biomass/

studies have been conducted on use of oxygenates in diesel including one by Southwest Research Institute that evaluated several alcohols, ethers and esters as oxygenates for diesel.[39]

3.1.2 Natural Gas

Natural gas is widely used in industrial boilers accounting for about 46,000 of the ICI boilers and process heaters. Natural gas is a desirable fuel for boilers due to its low content of ash and ease of handling, and ability to combust easily. However, DOE's energy information administration notes that the price of natural gas has more than doubled in the last decade. The primary constituent of natural gas is methane. Other paraffinic hydrocarbons such as ethane, propane, and butane as well as other gases such as nitrogen may be also present. The heating value of natural gas, like its composition, varies by region but usually is in the range from 900 to1000 Btu per standard cubic feet.[40]

3.1.3 Coal

Coal is also widely used in industrial boilers partly due to its lower price when compared to other fossil fuels. About 2500 ICI units burn coal. The ASTM classification for coal has four primary categories which rank coals based on volatile matter and fixed carbon content as well as heating value. The four categories (from low to high rank) are: lignite, submituminous, bituminous, and anthracite.[41] The higher rank coals have higher carbon content and are "older" i.e., they have undergone a comparatively longer coalification process. Anthracite coal has a carbon content of over 90% and is typically not used in industrial boilers. Most coal-fired industrial boilers burn either subbituminous coal (heating values ranging from 8,300 to 11,500 Btu/lb) or bituminous coal that (with heating values ranging from 10,500 to 14,000 Btu/lb). Lignite, a low rank coal that typically has a heating value below 8300 Btu/lb is not commonly burned in industrial boilers. All coal types in general have a higher content of ash and metals than fuel oil.

3.1.4 Non Fossil Fuel

Industrial boilers also burn a range of non-fossil fuels such as wood, tires, industrial sludge, baggasse, and municipal waste.

3.2 Heat Transfer Configuration

Boilers can be subclassified into four different types based on their heat transfer configuration set-up: (a) watertube; (b) firetube; (c) cast iron; and (d) tubeless. The choice of design depends on factors including the desired steam quality, thermal efficiency, size, economics, fuel type, and responsiveness. Watertube industrial boilers have a large size range while the other configurations are typically smaller than 10-30 MMBtu/hr.

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[39] Owens, E., "Oxygenates for Diesel Emissions Reduction" 7th Diesel Engines Emissions Reductions Workshop, Portsmouth, VA.

[40] Avallone, E.A., & Baumeister, T.(eds), "Mark's Standard Handbook for Mechanical Engineers," 9th Edition, 1987

[41] Note there are subcategories within these main categories.

3.2.1 Watertube

The watertube configuration is commonly used in industrial boilers. This is due to watertube boiler ability to: (a) produce high quality steam at high pressure (up to 1,750 psi) and high temperature (1,000°F); (b) achieve high thermal efficiency; (c) respond rapidly to changes in steam demand; and (d) potentially burn a variety of fuel types including coal, oil, gas, and other fuel types such as wood and municipal wastes. ICI watertube boilers range from 0.4 to 1500 MM Btu/hr.

A typical industrial watertube boiler is shown in Figure 3-1. A watertube boiler contains furnace and convective sections. Fuel is burned in the lower furnace section. Depending on the burner and fuel feed design set-up, gas, liquid, and solid fuels can be burned. The furnace section is lined with small diameter tubes which carry flowing water. Radiative heat from the fuel combustion flame heats the water in the tubes, creating steam.

The combustion flue gases are routed from the furnace into the "convective" section of the boiler. This section typically contains a superheater, reheater, economizer, and air preheater heat exchangers. The superheaters and reheaters are designed to increase the temperature of the steam generated in the furnace section. Following the superheater and reheater, an economizer counterflow tube heat exchanger is used to initally heat the boiler water before entering the furnace tube wall. The air heater is used to preheat the furnace combustion air. These separate operations all increase the boiler thermal operating efficiency.

Steam tubes are both imbedded in the furnace wall and mounted in the convective heat exchanger bundles which are exposed to the hot flue gases (such as in the superheater and reheater). The steam tubes are connected to one or more "steam drums" which collect the generated steam. Residues that collect and concentrate in the water/steam are collected at the "mud drum" located at the bottom of the tubes. Soot, ash, and other solid deposits that are generated from combustion tend to deposit and buildup on the boiler tube surfaces. "Sootblowers" are used periodically to clean the tubes of this particle buildup.

3.2.2 Firetube

Firetube design boilers are used for applications where smaller steam production and lower steam quality is required, and steam load requirements are relatively constant. Most units are less than 30 MM Btu/hr in size. Firetube boilers are compact, modular, and have low initial capital and installation cost. Packaged units usually have the capability of firing gas and liquids. Solid fuel firing in firetube boilers is rare due to clogging of tubes with ash and slag residue. Disadvantages to the use of firetube boilers include: (a) inability to superheat steam; (b) limit on steam pressure of 150 to 250 psi; (c) slow response to changes due to larger thermal inertia; and (d) lower thermal efficiency compared with watertube units.

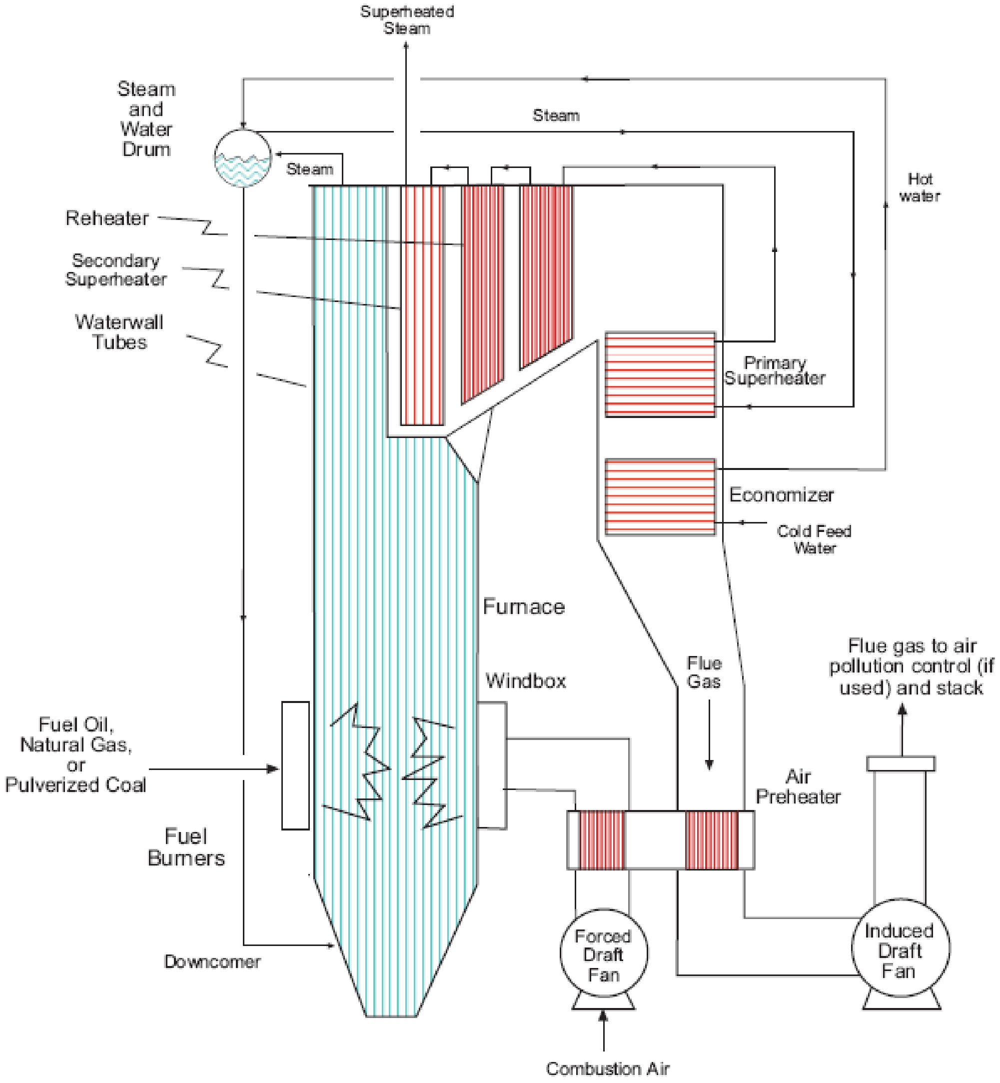

Figure 3-1: Watertube Boiler

Firetube boiler design is similar to a shell-and-tube heat exchanger. Shown generally in Figure 3-2, firetube boilers consist of a water-filled cylinder with immersed tubes passing through it, usually making multiple passes back and forth through the cylinder. Combustion gases are routed through the inside of the tubes and transfer heat to the pool of water to produce steam. Depending on the tube and firing arrangement, firetube boilers are generally classified as horizontal return tube, scotch marine (or shell) or firebox.

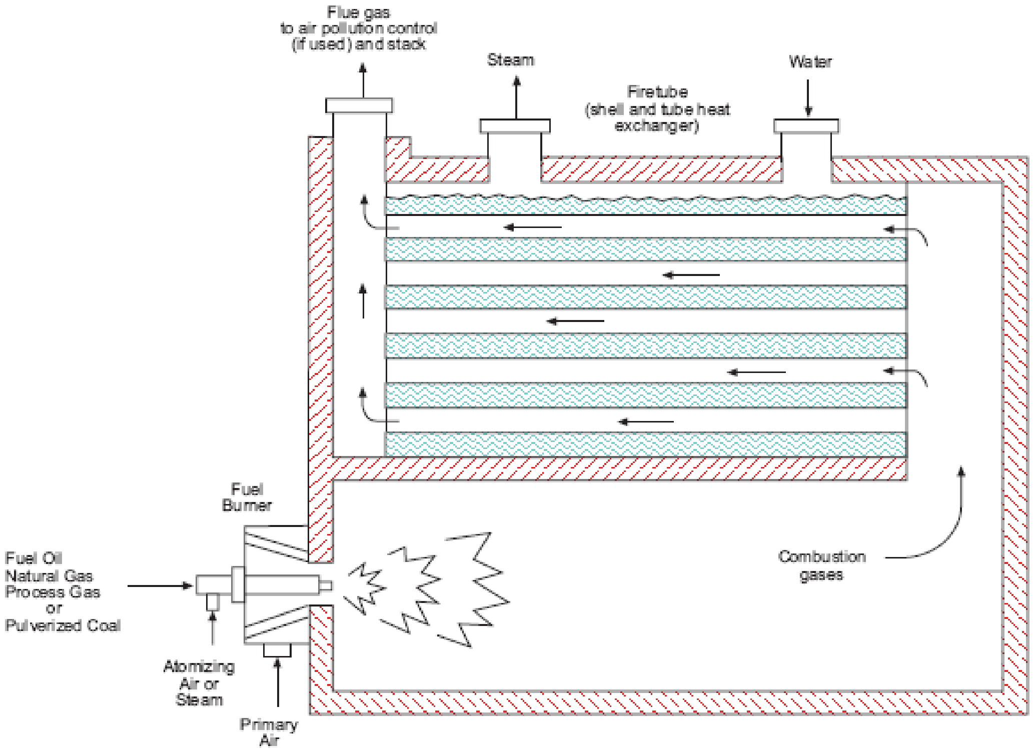

Figure 3-2: Firetube Boiler

3.2.3 Cast Iron & Tubeless Boilers

Cast iron boilers are typically smaller than 10 MM Btu/hr and operate by passing hot combustion gases through sets of heat exchanger tubes. They are generally used for producing low quality stream or hot water for commercial or institutional boiler applications. Pressure limits range from 15 to 100 psi for hot water and steam units.

The tubeless design is also limited to small applications. A tubeless boiler is typically vertically arranged with the burner located at the bottom or side of the unit. Steam is collected over the water in large jacket or U tube.

3.3 Burner Design

In a liquid/gas burner, atomized liquid fuels are mixed with combustion air in a swirling manner to provide a stable flame. Liquids can be fed and atomized in the main burner, or injected into the main flame through auxiliary lances. Liquid atomization is achieved through mechanical methods such as rotary cup or pressure atomization systems, or by twin-fluid nozzles with the assistance of high-pressure air or steam.[42] With a high surface area, the atomized particles vaporize quickly, forming a combustible mixture of fumes and combustion air that rapidly ignite and burn.

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[42] See Section 6.2.3 for a discussion on atomization systems.

Liquid ECF with high solids would need to be filtered prior to feeding given that the fuel must pass 200 mesh. Additionally, wastes with viscosities of greater than 50 cs would require pretreatment such as heating to decrease viscosity or blending with lower viscosity fuels prior to combustion. See Part Two, Section II.B.7 of the preamble to the proposed rule on restrictions on particle content and size.

In firetube boiler designs, a single burner is usually used. Watertube boilers use one of the configurations described below.

3.3.1 Suspension Firing -- Gas, Oil, and Pulverized Coal

Suspension firing designs are used in watertube boilers for gas (most commonly natural gas), liquids (e.g., fuel oil) and pulverized solids (e.g., pulverized coal). Suspension firing arrangements in watertube boilers include:

- <u>Wall (face) fired</u> – Most wall fired boilers are larger than 100 MM Btu/hr. Horizontally mounted burners in either a single (front) wall or opposed wall set-up.

    --<u>Front wall fired</u> -- Usually use a single burner, although there are some older and larger units which may use multiple burner rows. Newer units use single burners which can provide required control and turndown.

    --<u>Opposed wall</u> -- Used mostly in larger utility applications.

- <u>Tangential (corner) fired</u> -- Horizontally mounted burners in the four corners of a rectangular furnace, all firing toward the center to produce a cyclonic fireball.

- <u>Cyclone</u> -- Fuel (usually pulverized coal) and air is fed circumferentially into a cylindrical combustion chamber. This design is not widely used for industrial purposes (mostly used for larger utility applications).

Pulverized coal units can be either a wet bottom or dry bottom design, depending on if the ash is handled as a dry solid (dry bottom) or a molten liquid slag tap (wet bottom). Pulverized coal units are usually large (greater than 100 MM Btu/hr) due to the high cost of the coal pulverizing and handling equipment.

3.3.2 Stoker Firing -- Solids

Stoker fired boilers are designed to burn solid fuels (including coal, wood, municipal wastes, etc.) on a bed. Stoker systems are used on many coal-burning (and other solid fuel) industrial, commercial, and institutional boiler applications. This is because fuel handling and pretreatment procedures are not typically required.

Stokers are mechanical or pneumatic devices that feed solid fuels onto a grate at the bottom of the furnace and remove the ash residue after combustion. They consist of: (a) a fuel supply system; (b) stationary or moving grate which supports the burning mass of fuel and admits most of the combustion air to the fuel; (c) an overfire air system, provided over the burning bed, to complete combustion; and (d) an ash or residual discharge system. In most stokers, fly ash collected downstream of the furnace is reintroduced into the bed to ensure complete combustion of the fuel.

There are three main classes of stoker set-ups: (a) underfeed, (b) overfeed, and (c) spreader stoker:

3.3.3 Fluidized Bed Boilers - Solids

Fluidized bed systems can be used to efficiently combust various types of solid and liquid fuels although most ICI boilers fire coal and to a lesser extent other solid fuels. Size reduced fuel (ground or shredded) is fed into a bed of inert particles (sand and/or a sorbent such as limestone). The bed is kept suspended ("fluidized") by an upward flow of combustion air through the bed. Fluidized beds operate at lower temperatures than conventional suspension pulverized coal fired boilers.

3.4 Emissions from Industrial Boilers

The emissions database developed for the industrial boiler NESHAP[43] contains information from fewer than 2000 units. This section discusses emissions of CO, methane and PCDD/F. Nondioxin organic HAP emissions from industrial boilers are discussed in Section 5.1.

CO Emissions

The industrial/commercial boiler database contains CO emissions data from nearly 1000 runs. Less than 25% of the CO measurements are from a CEMS – many sources appeared to have performed a one time test.

Table 3-3 summarizes the CO data by fuel type (note that there were dozens of fuels and fuel mixes and certain fuel types are combined for ease of presentation).

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[43] See 63 Fr 55218 (Sept. 13, 2004) and 40 CFR Part 63, Subpart DDDDD.

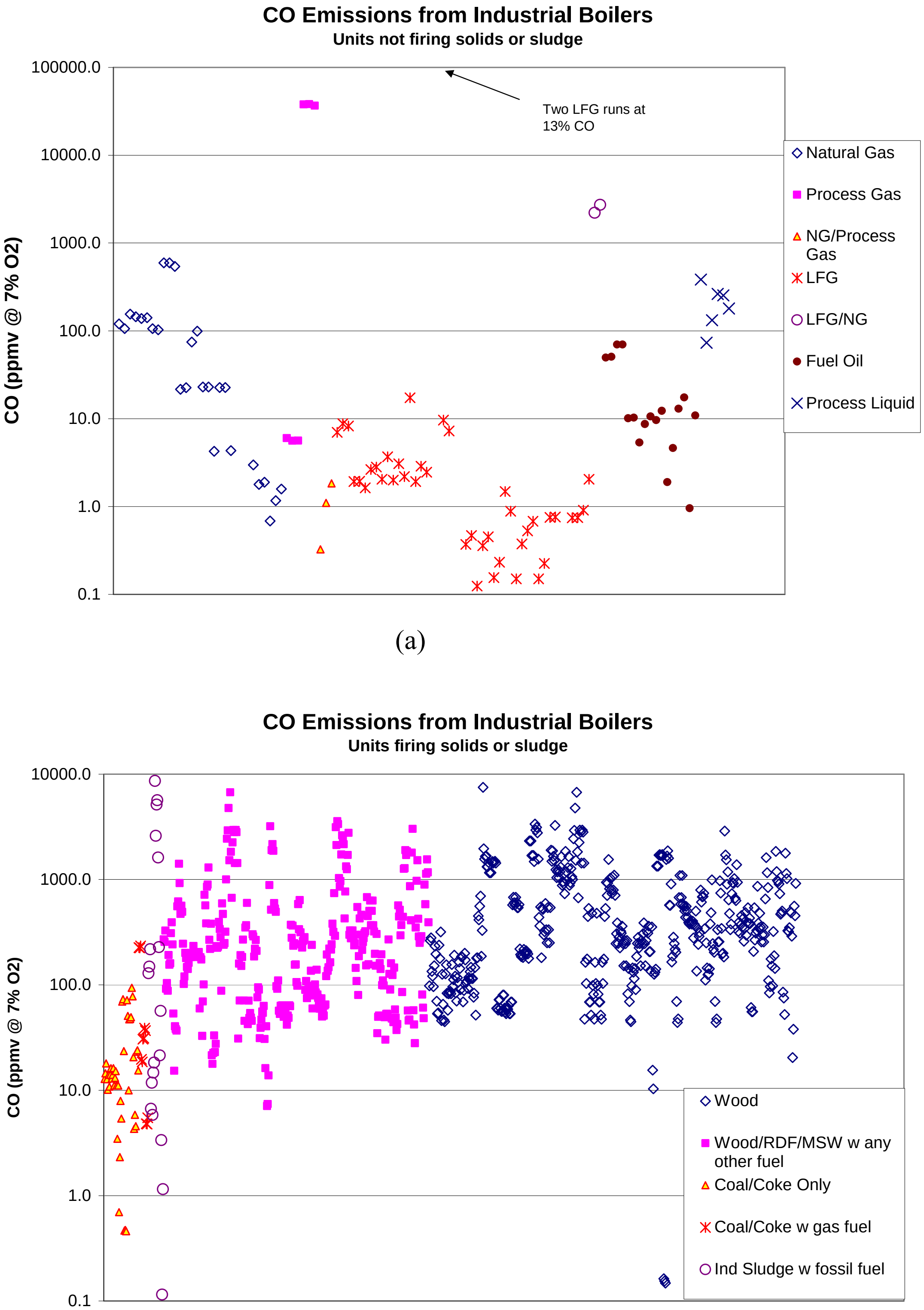
	CO Emissions (ppmv @ 7% O2)				# of Runs		
Fuel Type(s)	Min	Max	Avg	Median	Total	<100 ppmv	Percent runs < 100 ppmv
Natural Gas only	**0.10**	**595**	**102**	**23**	**30**	**11**	**37%**
Process Gas only	5.6	38200	18803	18403	6	3	50%
NG/Process Gas only	0.325	1.83	1	1.1	3	0	0%
Landfill Gas only	0.02	131000	5654	1.2	46	44	96%
Fuel Oil only	**0.96**	**70**	**21**	**10.6**	**17**	**17**	**100%**
Coal and/or Coke only	**0.46**	**94**	**22**	**14**	**43**	**43**	**100%**
Coal/Coke w gaseous fuel	**4.8**	**234**	**73**	**31**	**12**	**9**	**75%**
Process Liquid	73.4	384	214	217	6	1	17%
Wood only	0.148	7480	619	323	459	86	19%
Wood/RDF/MSW w any other fuel	7.1	6710	489	202	332	109	33%
Industrial Sludge w fossil fuel	0.115	8630	1290	56.6	19	10	53%

Table 3-3: CO Emissions by run (ppmv @7% O2) from Industrial and Commercial Boilers

The table shows the range of CO emissions for each fuel type or combination as well as showing the fraction of individual CO runs below 100 ppmv. Emissions are shown in bold type for facilities that may burn ECF. The other sources are not likely to burn ECF because:

a) They are not firing fossil fuel, or
b) They are firing wood or MSW which would require either a stoker or a fluidized bed unit.

These data are also plotted in Figure 3-3. There are 11 instances where natural gas fired units exceed 100 ppmv CO. These units with high CO do not specify the boiler design type. All units firing fuel oil only and all those firing coal and coke only are below 100 ppmv for all runs. There are 3 runs with CO>100 from a circulating fluidized bed boiler that burns coal with natural gas.



(a)

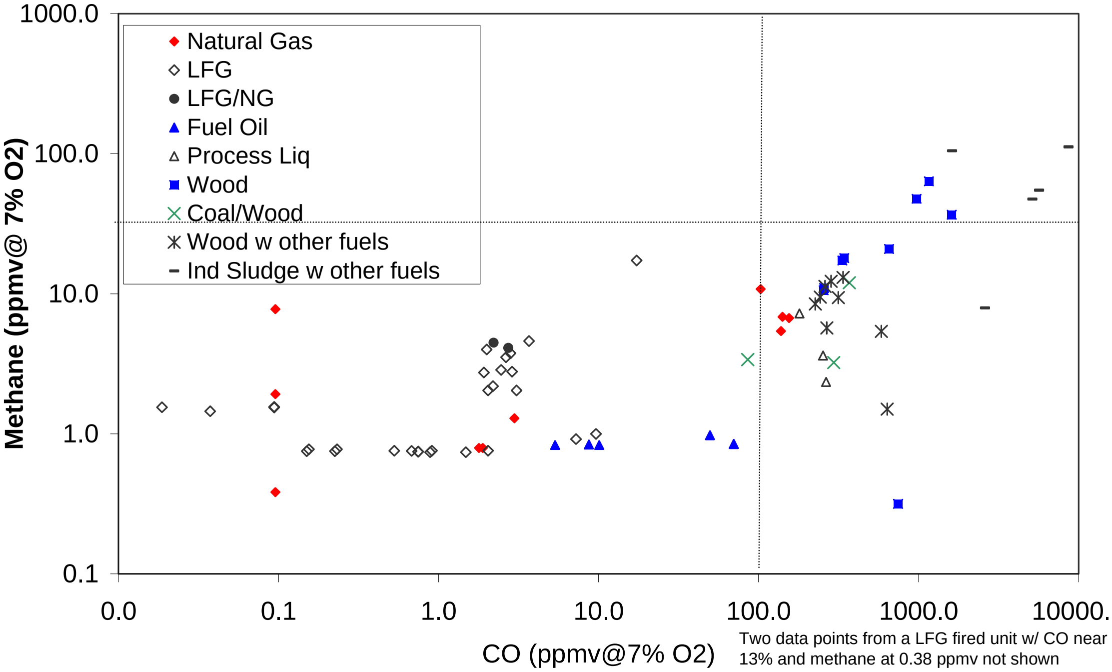
(b)

Fig 3-3: CO Emissions from industrial boilers (a) Gas/liquid fired units, (b) Solid/sludge fired units.

CO vs. Methane

Figure 3-4 shows methane emissions vs. CO emissions for all boilers for which both CO and methane emissions are available. The vertical and horizontal lines on the plot show CO = 100 ppmv and methane =30 ppmv (which is equivalent to THC=10 ppmv on a propane basis if methane is the only hydrocarbon present)

All fuel oil fired units have low methane emissions with most around 1 ppmv. No data are available from units that fire only coal. A few natural gas fired units have methane emissions near 10 ppmv. This plot also shows that there are no instances where methane emissions exceed 30 ppmv when CO is below 100 ppmv.



Two data points from a LFG fired unit w/ CO near 13% and methane at 0.38 ppmv not shown

Fig 3-4: Methane vs. CO emissions for Industrial Boilers

PCDD/F

For dioxins and furans, only 15 runs from five test conditions are available for oil fired boilers. As seen in Table 3-4, emissions were generally low, with test condition averages ranging from 0.012 to 0.028 ng TEQ/dscm and an average value of 0.017 ng TEQ/dscm.

Unit ID	PCDD/F(ng TEQ/dscm @7% O2)			
	R1	R2	R3	Cond Avg
E212.002c	0.017	0.014	0.025	0.019
E212.002u	0.018	0.022	0.043	0.028
E22.002	0.012	0.010	0.013	0.012
E251b.003c	0.018	0.014	0.017	0.016
E251b.003u	0.011	0.014	0.013	0.013
			Average	0.017

Table 3-4: PCDD/F Emissions from Oil Fired Industrial Boilers

4 CO as an Indicator of Incomplete Combustion

Carbon monoxide is a universally accepted indicator of combustion efficiency and limits on CO have been historically used to control emissions of organic HAP. For example, in the recently promulgated industrial boiler NESHAP, CO is used as a surrogate for organic HAP.[44] CO is a conservative indicator of deteriorating combustion conditions. Generally when CO is low, organic emissions are low because destruction (DRE) is high. However, because CO oxidation to CO_2 is the slowest and last step in the combustion of organic waste, high DRE and low organics emissions levels can be achieved at high CO levels.

4.1 Combustion Failure Modes

EPA has identified four combustion failure modes which would result in poor DRE.[45]

1. **Total Ignition Failure**: Combustion does not occur and products of incomplete combustion (PICs) are not formed. This results in the absence of CO, high HC if the unreacted fuel/waste has significant organic content, and low DRE.
2. **Partial Ignition Failure**: Part, but not all, of the fuel/waste combusts forming PICs. This results in high CO, high HC if the unreacted fuel/waste has significant organic content, and low DRE.
3. **Combustion Air Failure**: Insufficient combustion air leads to incomplete combustion. Very high CO concentrations result when combustion air is less than that required to stoichiometrically burn the waste and fuel. As the air to fuel/waste ratio decreases further and below stoichiometric, high HC concentrations (initially dominated by methane) result; and, at even lower air to fuel/waste ratios, low DRE may result as non-methane organics begin to appear.
4. **Rapid Quench Failure**: The fuel/waste is incompletely combusted because it is not exposed to temperatures necessary to sustain oxidation for a sufficient period of time. The combustion gas cools so quickly that combustion is interrupted. The resulting CO emissions are high because the oxidation of CO to CO_2 is the last step in the combustion process, and the reaction rate of CO oxidation is slow. This failure mode may also result in high emissions of HC and low DRE.

Of the above failure modes, only total ignition failure would result in high DRE without correspondingly high CO. EPA also recognized that DRE failure could occur if the POHC was injected at low concentrations, especially if the POHC was also a likely PIC.

In addition, EPA examined data from hundreds of DRE tests with concurrent measurements of CO and HC. The rare instances where DRE failure occurred without

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[44] USEPA, "National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule," September 2004. See 69 FR 55223

[45] USEPA, Draft Technical Support Document for HWC MACT Standards(NODA), Volume II: Evaluation of CO/HC and DRE Database," April 1997

corresponding high emissions of CO were all explainable. EPA concluded that CO is a conservative indicator of DRE failure--in other words DRE failures would usually be accompanied by high CO. Note that EPA has supplemented this analysis by including more recent data, as presented in Appendix A.

4.2 CO vs. DRE

Early studies by EER and others in the 1980's pointed to a potential correlation between POHC emissions and CO.[46] Subsequent work, primarily by Dellinger et al at UDRI, generally either found no correlation or a poor correlation. However, the use of a CO limit as a DRE failure indicator does not require that CO and DRE be directly correlated; rather, a DRE failure must simply be indicated by high CO.

In 1986, Hall et al tested a 12 component POHC mixture in a laboratory scale thermal destruction unit.[47] The primary purpose of the work was to identify thermally stable POHCs for future emissions testing during a trial burn. Many of the compounds were constituents (including nitrogenated/halogenated organics and oxygenates). An important characteristic of this experiment was that, while it was intended to simulate a liquid injection incinerator, the tests were conducted in a <u>flameless</u> controlled temperature reactor. The POHC mixture was injected into a stream containing a nitrogen/air mixture (at either 2.5% O_2 or 10% O_2). Water vapor was introduced to the stream such that the moisture content was 5%. The concentrations of most of the POHC constituents were 1000 ppmv in air (acetone and methanol were at higher concentrations). Tests were conducted at two temperatures 650 °C(~1200 °F) and 775 °C (1430 °F) at residence times of 0.5 seconds and 2 seconds. Tests showed very poor DREs in general. In some cases poor DREs were accompanied by low CO (as low as 15 ppmv).[48] Under the conditions most conducive to POHC destruction-among those tested (10% oxygen, 2 sec residence time and 775 °C), all constituents were below detection limits, with the exception of chlorobenzene and acetonitrile which had DREs of about 98%. The authors conclude that "The apparent lack of correlation between CO levels and changes in the decomposition of the constituents of the mixture places doubt on the usefulness of CO measurements as an indicator of destruction efficiency."

However, we believe that this study in no way invalidates the use of CO as the sole indicator of good DRE because:

1. The study was conducted in a flameless decomposition reactor and generally creates conditions similar to "total ignition failure," which is one of the four DRE failure modes identified by EER's work in the 1990's.

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[46] La Fond, et al, 1985, "Evaluation of Continuous Performance Monitoring Techniques for Hazardous Waste Incinerators.

[47] Hall, D.L., Dellinger, B., Graham, J.L., and Rubey, W.A. "Thermal Decomposition Properties of a Twelve Component Organic Mixture." <u>Hazardous Waste & Hazardous Materials</u>, Volume 3, November 4 1986, pg 441-449. Lieber, Inc. Publishers.

[48] Note that the low CO measurements are somewhat deceptive. The POHCs were injected at low concentration with no auxiliary fuel. There was very little carbon available to form CO. The CO concentrations were not corrected to 7% oxygen and this correction would be complicated because the oxidant was a mixture much higher in nitrogen than standard combustion air. A preliminary estimate suggests that the 15 ppm CO would be over 100 ppm at 7% O2, if also corrected for nitrogen dilution.

2. The reactor temperatures were low (< 1430 °F), well below temperatures one would expect to see in a combustion chamber of a typical boiler or incinerator.
3. The CO analysis was not done using a CO CEMS. Instead, gas samples from the exhaust were collected and sent through a separation column to separate the CO. This CO stream was then sent through a methanizer to be converted to methane, which was subsequently analyzed by a FID. Moreover the experimenters used a 10,000 ppmv CO in helium as a standard. Therefore, accuracy of the low CO measurements is questionable.
4. And *most importantly*, we believe that since the study was conducted during a time when CO compliance limits were established based on levels achieved during the trial burn, the authors' intent was to point out that basing CO limits on the trial burn was inappropriate. The paper does not say anything about the 100 ppmv CO level that was later developed as a level that minimizes POHC emissions and PIC formation. See the EPA handbook "Guidance on Setting Permit Conditions and Reporting Trial Burn Results EPA/625/6-89/019, p.52."

In work published in the Journal of Hazardous Materials, Dellinger et al studied the flameless decomposition of a 3-component POHC mixture (toluene, ethyl cyanide, and 1,3,5 trichlorobenzene) in an isothermal flow reactor.[49] The mixture was exposed to a given temperature for a 2 second residence time at an equivalence ratio of 3.0 (or 33% theoretical air). Under these fuel-rich conditions, up to 50 PICs were detected from this 3-POHC mixture. The authors arrived at the following conclusions while acknowledging that the conclusions could be debatable:

1. PIC formation is a natural consequence of POHC destruction.
2. The formation and destruction of PICs are kinetically controlled, and levels predicted by thermodynamic equilibrium calculations are often orders of magnitude too low.
3. Many of the PICs appeared more stable than the parent POHCs because they are exposed to high temperatures for an effectively shorter residence time. Thus, they may require a higher destruction temperature.

Another study was conducted in a pilot-scale 150,000 Btu/hr turbulent flame reactor (TFR).[50] A mixture containing a selection of chlorinated hydrocarbons in heptane (>90%) was introduced to the reactor via a pressure atomizing nozzle. Unlike the previous Dellinger experiments, the overall stoichiometry was fuel-lean, with exhaust oxygen concentrations varying between 3% and 6.5%. Exhaust CO and oxygen were measured using non-dispersive IR and paramagnetic analyzers respectively. Exhaust VOCs were analyzed using a VOST train. The approach was, however, limited to compounds with boiling points below 150 °C. The authors show that no correlation was found between the POHC fraction remaining in the stack and CO emissions.

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[49] Dellinger, B. Taylor, P., and Tirey, D., "Pathways of Formation of Chlorinated PICs from the Thermal Degradation of Simple Chlorinated Hydrocarbons." Journal of Hazardous Materials, Elsevier Publishers, 1989.

[50] Staley, Richards, Huffman, Olexsey, and Dellinger. "On the Relationship Between CO, POHC and PIC Emissions from a Simulated Hazardous Waste Incinerator." JAPCA 39: 321-327, 1989.

The authors state that the predominant pathway of organics destruction is formation of CO with subsequent oxidation to CO_2, and that the CO to CO_2 oxidation is the slowest rate determining step. The authors also contend that the CO to CO_2 conversion can only occur in an oxidative environment (and most likely occurs by oxygen atom transfer involving the hydroxyl (OH) radical). The contention is that small amounts of the feed will see localized regions that are fuel rich and/or low in temperatures and residual POHC, and PIC emissions are due to pyrolysis pathways (oxygen deficient pockets). Also, low temperatures (<800°C) are required before measurable POHC/PIC emissions occur in oxidative pathways. Since POHC degradation and PIC formation/degradation can occur in different parts of the combustor than reactions involving CO formation/destruction, CO emissions may not directly correlate to POHC destruction efficiency.

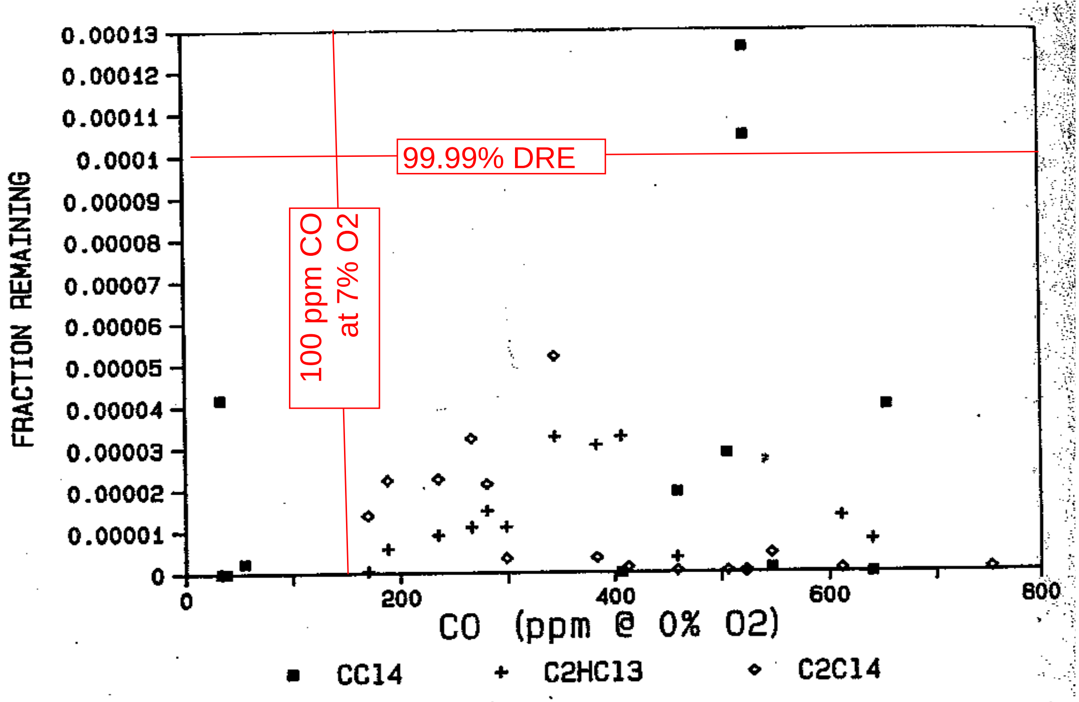

Figure 4-1: POHC Fraction Remaining vs. CO (reproduced from Staley et al, 1989-lines for 100% CO, 99.99% DRE added to original plot)

The authors used the above diagram to illustrate that POHC emissions do not correlate with CO emissions. The plot shows POHC fraction remaining (1-DRE/100) as a function of measured CO emissions.

However, note the graph does show that:

- There are only two cases where DRE is less than four nines and these occur at high CO (525 ppm @ 0% O_2 or 350 ppm @ 7% O_2).
- For the four cases where CO is less than 100ppmv, DRE is well above 99.99%.

Also, PIC emissions measured during these experiments were about an order of magnitude lower than the highest POHC emissions.

4.3 Conclusions

CO has historically been used as an indicator for good combustion and a surrogate for organic HAP. Although several studies have shown no direct correlation between CO and DRE, the use of CO as good combustion indicator does not require there to be a direct correlation--only that a DRE failure would be indicated by high CO levels. Also, the reason there is no correlation is that, as explained earlier, high DREs can occur even at relatively high CO levels (i.e., because CO is a conservative indicator of combustion efficiency). However, under oxidative conditions seen in boilers, a CO limit coupled with the other burner conditions required for ECF combustion would ensure that organic emissions are minimized. (Emissions are low and DREs are high when CO is low, and high organic emissions are evidenced by high CO emissions).

5 Organic Emissions & Qualitative Risk Assessments

This section presents the results of several analyses that were conducted to assess whether emissions of toxic organic compounds from ECF-fired boilers could be expected to be comparable to emissions from oil-fired industrial boilers, and whether dioxin/furan emissions from burning ECF could be expected to be protective of human health and the environment. These include:

1. A comparison of speciated organic emissions data between fuel oil fired industrial boilers and watertube steam boilers (that are not stoker-fired) burning hazardous waste.
2. An abbreviated comparative risk assessment for dioxin/furan emissions from hazardous waste-burning watertube steam boilers.

In the absence of emissions data from boilers burning ECF, we evaluated organic emissions data from watertube steam boilers (that were not stoker-fired) burning hazardous waste and compared those emissions with emissions from oil-fired industrial boilers. Using hazardous waste boiler emissions as a surrogate for ECF boiler emissions is reasonable because the ECF exclusion would be conditioned on the ECF boiler operating under conditions that ensure good combustion efficiency. The operating conditions would be at least as stringent as those for RCRA-permitted hazardous waste boilers. (See discussion in Part II: Section II.A of the preamble to the proposed rule.)

To perform these analyses, we evaluated boiler designs for boilers with risk burn test data in the hazardous waste combustor database.[51] Since the HWC database only contains information prior to 2003-2004, more recent test reports for risk burn testing were obtained. The boilers were screened to exclude firetube boilers, stoker-fired coal-boilers, as well as process heaters. In addition, data from three watertube boilers whose combustion chamber was not of integral design with the boiler section were also screened out.[52]

The remaining 27 boilers are listed on Table 5-1. The table shows source ID number, EPA ID number, facility name and location as well as information on burner design. Note that all of these boilers are classified as liquid fuel boilers under the HWC MACT standards. There were no risk burn data available from pulverized coal-fired boilers.

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[51] This database is available from the OSW website on the HWC MACT at http://www.epa.gov/epawaste/hazard/tsd/td/combust/finalmact/index.htm

[52] These are two Rubicon units in Geismar, LA (Source IDs 812 & 813) and a BASF unit (834) in LA. These units have a boiler section that is separated by ductwork from the primary combustion chamber and, thus, do not meet the definition of a boiler in 40 CFR 260.10.

Source ID	EPA ID Number	Facility Name	Unit ID Name	City	State	APCS	Watertube?	Stoker?	Process Heater?	Integral Design?
2007	KSD007237746	Air Products Manufacturing Corp.	COEN boiler	Wichita	KS	None	Yes	No	No	Yes
741	KYD006390017	Rohm and Haas Company	Unit No. 100	Louisville	KY	None	Yes	No	No	Yes
753*	LAD041581422	Union Carbide Corp.	Boiler 31	Hahnville	LA	None	Yes	No	No	Yes
756*	LAD059130831	DSM Copolymer Inc.	No. 3 boiler	Addis	LA	None	Yes	No	No	Yes
818	LAD010390599	Westvaco	Boilers No. 2 and 3 (common ESP and stack)	DeRidder	LA	ESP	Yes	No	No	Yes
822	LAD000778381	Exxon Chemical Co.	C-Boiler	Baton Rouge	LA	None	Yes	No	No	Yes
828	LAD020597597	Angus Chemical Company	No. 7 Boiler	Sterlington	LA	None	Yes	No	No	Yes
836	LAD040776809	BASF	No. 6 Boiler	Geismar	LA	None	Yes	No	No	Yes
2000	LAD057117434	Georgia Gulf Chemicals and Vinyls, LLC.	Nebraska Boiler	Plaquemine	LA	None	Yes	No	No	No but bona fide boiler
1000	NCD042091975	Mallinckrodt Inc.	Boiler No. 2	Raleigh	NC	None	Yes	No	No	No info
MERCK	NJ?	Merck	Boiler # 9	Rahway	NJ	SCR	Yes	No	No	No info
2008	PAD002312791	Sunoco Inc. (R & M) Frankford Plant	Boiler No. 2	Philadelphia	PA	None	Yes	No	No	No info
2021	TXD000461533	Union Carbide Coporation	Boiler 53	Texas City	Texas	None	Yes	No	No	Yes
720	TXD078432457	Celanese Ltd., Chemical Group Clear Lake Plant now BOC Group	MH5A	Pasadena	TX	None	Yes	No	No	Yes
721	TXD026040709	Celanese Ltd	Boiler No. 4	Bay City	TX	None	Yes	No	No	Yes
759	TXD008079642	E.I. duPont de Nemours & Co., Inc. **now Invista**	Boiler No. 7	Orange	TX		Yes	No	No	Yes
760	TXD008079642	E.I. duPont de Nemours & Co., Inc. **now Invista Owned**	Boiler No. 8	Orange	TX	None	Yes	No	No	Yes
761	TXD008079642	E.I. duPont de Nemours & Co., Inc. **now Invista**	ADN North	Orange	TX	None	Yes	No	No	Yes
767	TXD008077190	Goodyear Tire and Rubber Company	Boiler B-103	Beaumont	TX	None	Yes	No	No	No info
833	TXD008081697	BASF Corporation	Neol Boiler	Freeport	TX	None	Yes	No	No	yes
843	TXD008092793	Dow Chemical Company	B-902	Freeport	TX	None	Yes	No	No	Yes
910*	TXD000461533	Union Carbide Corporation	Boiler 5	Texas City	TX	None	Yes	No	No	Yes
1018	TXD008113441	Celanese Ltd	Boiler No.16	Bishop	TX	None	Yes	No	No	Yes
2012	TXD008123317	E.I. Du Pont Nemours & Company, Inc. **now Invista**	Boiler No. 7	Victoria	TX	None	Yes	No	No	Yes
2013	TXD008123317	E.I. Du Pont De Nemours & Company, Inc.	Boiler Nos. 3 & 4	Victoria	TX	None	Yes	No	No	Yes
2016	TXD008123317	E.I. Du Pont De Nemours & Company, Inc.	Boiler No. 1	Victoria	TX	None	Yes	No	No	Yes
771	WAD092899574	Kalama Chemical (BF Goodrich)	U-3 Boiler	Kalama	WA	FF	Yes	No	No	No info

Table 5-1: Hazardous Waste Burning Watertube Steam Boilers with Risk Burn Data

5.1 Individual Organics

5.1.1 Industrial Boiler Benchmark

The Industrial Boiler emissions database discussed in Section 3.4 above was surveyed for speciated organics data. The following data were screened out:

1. Nondetects
2. Emissions from firetube boilers, stokers, and process heaters.[53]
3. Emissions from boilers other than those that fired only fuel oil (Boilers that fired other fuels in combination with fuel oil were also screened out.)
4. Emissions from distillate fuel oil boilers.[54]
5. Emissions for nontoxic compounds—compounds not listed as RCRA hazardous organics in 40 CFR Part 261, Appendix VIII, or not listed as CAA hazardous air pollutants (HAP)[55].

The remaining emissions data were converted to standard units (ug/dscm @ 7% O_2)[56] and the results are shown in Table 5-2. The table shows emissions information for 26 specific organics, including number of total test conditions, average emissions as well as the range of emissions. The 95th percentile emissions level, which is used as a benchmark for comparison with hazardous waste boilers, (discussed below in Section 5.1.2) is shown in bold font. The hazardous organics with the highest emission concentrations among industrial boilers burning fuel oil are formaldehyde, benzene, toluene, and xylene.

In addition to the information gathered from the emissions database, the table also shows available AP-42 fuel oil combustion data for these organics.[57]

5.1.2 Comparative Data from Hazardous Waste Boilers

Organic emissions data were extracted for 28 risk-burn test conditions from 27 hazardous waste boiler facilities shown in Table 5-1. (Note--Two units had two test conditions each and one unit did not perform testing for individual organics). In this section, we discuss the procedure used to extract emissions data from the risk-burn test reports and compare emissions from hazardous waste boilers to emissions from oil-fired industrial boilers.

The risk burns involved separate sampling trains for evaluating the target analytes among VOCs and SVOCs. In a few cases a PAH sampling train was also used. The test reports typically contained run by run emissions for three runs for each test condition. However, each test run was a composite measurement:

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[53] Information on boiler type was limited. Only those boilers specified as firetube, stoker, or process heater were screened out.

[54] A majority of the units with emissions data burn residual fuel oil.

[55] See http://www.epa.gov/ttn/atw/orig189.html for the list of HAP.

[56] Unless specifically noted otherwise all organics emissions data in this section are corrected to 7% O_2.

[57] USEPA, "AP 42:Compilation of Air Pollution Emissions Factors, Vol I: Stationary Point and Area Sources," 5th Edition, 1995, Ch.1.3 Fuel Oil Combustion.

		1,1,1-Trichloroethane	2-Methylnaphthalene	Acenaphthene	Acetaldehyde	Acrolein	Anthracene	Benz(a)anthracene	Benzene	Benzo(a)pyrene	Benzo(b)fluoranthene	Benzo(b,k)fluoranthene	Benzo(g,h,i)perylene	Chrysene	Dibenz(ah)anthracene	Dichloromethane (Methylene Chloride)	Ethylbenzene	Fluoranthene	Fluorene	Formaldehyde	Indeno(1,2,3-cd)pyrene	Naphthalene	o-Xylene	Phenanthrene	Pyrene	Toluene
	CAS	71-55-6	91-57-6	83-32-9	75-07-0	107-02-8	120-12-7	56-55-3	71-43-2	50-32-8	205-99-2	56832-73-6	191-24-2	218-01-9	53-70-3	75-09-2	100-41-4	206-44-0	86-73-7	50-00-0	193-39-5	91-20-3	95-47-6	85-01-8	129-00-0	108-88-3
	MW	133	142	154	44	56	178	228	78	252	252	252	276	228	278	85	106	202	166	30	276	128	106	178	202	92
AP 42 Emission Factors	lb/1000 gal	2.4E-04		2.1E-05			1.2E-06	4.0E-06	2.1E-04			1.5E-06	2.3E-06	2.4E-06	1.7E-06		6.4E-05	4.8E-06	4.5E-06	3.3E-02	2.1E-06	1.1E-03	1.1E-04	1.1E-05	4.3E-06	6.2E-03
	ug/dscm @ 7% O2	1.8		0.16			0.009	0.031	1.7			0.011	0.018	0.018	0.013		0.49	0.038	0.035	256	0.02	8.77	0.85	0.081	0.033	48
Fuel Oil fired-Industrial Boiler Database Emissions (ug/dscm @7%O2)	# of runs	5	32	26	5	3	19	6	32	1	4	4	6	14	6	5	5	33	36	54	6	72	5	58	28	32
	Average by run	1.4	0.15	0.21	48.1	18.2	0.03	0.14	20.2	0.005	0.01	0.07	0.08	0.09	0.03	37	0.41	0.14	0.08	335	0.07	40	0.66	0.21	0.07	58
	min-run	0.52	0.01	0.00	10.0	17.7	0.002	0.05	0.4	0.005	0.01	0.05	0.03	0.012	0.009	21	0.22	0.00	0.01	2.1	0.02	0.08	0.37	0.01	0.00	1.8
	95%ile by run	2.2	0.92	0.73	70.5	18.9	0.08	0.28	133	0.01	0.02	0.10	0.17	0.23	0.06	58	0.62	0.49	0.43	795	0.15	304	1.20	0.78	0.20	227
	Max	2.3	1.45	0.94	71.3	19.0	0.11	0.28	198	0.005	0.03	0.10	0.17	0.32	0.06	61	0.66	0.94	0.64	9668	0.15	347	1.33	3.17	0.28	728
	# of TCs	2	11	11	2	1	8	4	12	1	3	4	4	7	4	2	2	16	15	20	4	25	2	20	15	11
	Min-TC	0.8	0.02	0.01	18	18	0.003	0.10	0.56	0.005	0.01	0.05	0.03	0.01	0.01	33	0.30	0.003	0.02	3.9	0.02	0.19	0.37	0.01	0.004	2.3
	Average	1.3	0.16	0.18	43	18	0.03	0.13	19.9	0.005	0.01	0.07	0.07	0.08	0.02	37	0.39	0.13	0.07	629	0.06	42	0.61	0.2	0.1	57
	Max-TC	1.8	1.1	0.59	68	18	0.08	0.16	158	0.005	0.02	0.10	0.11	0.18	0.04	41	0.49	0.61	0.52	9668	0.10	323	0.85	1.6	0.20	348
	95%ile by TC	**1.7**	**0.7**	**0.56**	**66**	**18**	**0.06**	**0.16**	**90**	**0.005**	**0.02**	**0.10**	**0.11**	**0.18**	**0.04**	**40**	**0.48**	**0.47**	**0.22**	**1220**	**0.10**	**276**	**0.83**	**0.92**	**0.15**	**233**

Table 5-2: Hazardous Organic Emissions Data for Oil-Fired Industrial Boilers

VOC- Each run is a composite of at least 3 measurements (typically 3 or more VOST tube pairs (tenax for the front half, and tenax/charcoal for the back half) and a condensate measurement). VOST tube pairs are sometimes analyzed separately but the separate front and back half data were rarely available.

SVOC/PAH- Typically there is only one pair of tenax tubes. Separate front and back half data were rarely available.

Stack testing companies often use the "<" qualifier to data that are either fully nondetect or partially nondetect. So, looking at individual VOST tube pair data for VOCs and run level data for SVOCs, we made the following assumption:

> If data had a "<" qualifier we assumed that this was a nondetetect unless there was information available to distinguish nondetects from partial nondetects.

The emissions from detect runs (or the detect component of partial detect runs) were tabulated for each test condition for each of the 26 organic compounds for which we also have emissions data for oil-fired industrial boilers. The results are shown in Table 5-3 for all 28 test conditions. An "NM" in the table indicates that the constituent was not measured by that source, while an "ND" indicates that the constituent was measured but all three runs were fully nondetect. For the other cases, the condition averages of the detect runs (or detect component of partial detect runs) are shown in units of ug/dscm corrected to 7% oxygen. The last row on the table shows the number of conditions with detect (or partial detect) runs for each compound. There are total of 173 such conditions when considering all 26 compounds.

		1,1,1-Trichloroethane	2-Methylnaphthalene	Acenaphthene	Acetaldehyde	Acrolein	Anthracene	Benz(a)anthracene	Benzene	Benzo(a)pyrene	Benzo(b)fluoranthene	Benzo(b,k)fluoranthene	Benzo(g,h,i)perylene	Chrysene	Dibenz(ah)anthracene	Dichloromethane (Methylene Chloride)	Ethylbenzene	Fluoranthene	Fluorene	Formaldehyde	Indeno(1,2,3-cd)pyrene	Naphthalene	o-Xylene	Phenanthrene	Pyrene	Toluene	Xylenes
	CAS	71-55-6	91-57-6	83-32-9	75-07-0	107-02-8	120-12-7	56-55-3	71-43-2	50-32-8	205-99-2	56832-73-6	191-24-2	218-01-9	53-70-3	75-09-2	100-41-4	206-44-0	86-73-7	50-00-0	193-39-5	91-20-3	95-47-6	85-01-8	129-00-0	108-88-3	1330-20-7
Fuel-Oil Industrial Boiler Benchmark - 95% ile test condition average (ug/dscm @7% O_2)		**1.7**	**0.7**	**0.56**	**66**	**18**	**0.06**	**0.16**	**90**	**0.005**	**0.02**	**0.10**	**0.11**	**0.18**	**0.04**	**40**	**0.48**	**0.47**	**0.22**	**1220**	**0.10**	**276**	**0.83**	**0.92**	**0.15**	**233**	**2993**
HW Boiler Average Emissions by source-(detects only) (ug/dscm @ 7% O2)	1000	ND	ND	ND	NM	NM	ND	ND	ND	ND	ND	ND	ND	ND	ND	20	ND	ND	ND	NM	ND	ND	ND	ND	ND	22.8	NM
	1018	ND	ND	ND	99.9	6.61	ND	ND	43.7	ND	ND	ND	ND	ND	ND	2	0.39	ND	ND	659	ND	ND	ND	ND	ND	2.0	ND
	2000	ND	ND	ND	NM	NM	ND	ND	ND	ND	ND	ND	ND	ND	ND	ND	ND	ND	ND	NM	ND	1.37	ND	0.48	ND	ND	ND
	2007	NM	NM	0.02	NM	NM	0.03	0.004	28	0.01	NM	NM	NM	0.01	0.001	22	NM	NM	NM	NM	0.03	0.57	NM	NM	0.091	2.1	NM
	2008C20	ND	0.07	ND	NM	NM	ND	ND	2.26	ND	ND	ND	ND	ND	ND	23	2.34	0.01	0.01	NM	ND	ND	ND	0.04	0.01	1.4	4.51
	2008C21	NM	0.09	ND	NM	NM	ND	ND	NM	ND	ND	ND	ND	ND	ND	NM	NM	0.01	0.01	NM	ND	0.12	NM	0.04	0.0117	NM	NM
	2012	ND	ND	ND	NM	NM	ND	ND	ND	ND	ND	ND	ND	ND	ND	76	ND	ND	ND	NM	ND	ND	ND	ND	ND	39.0	ND
	2013	ND	ND	ND	NM	NM	ND	ND	193	ND	ND	ND	ND	ND	ND	58	ND	ND	ND	NM	ND	ND	ND	ND	ND	2.1	ND
	2016	ND	ND	ND	NM	NM	ND	ND	ND	ND	ND	ND	ND	ND	ND	50	ND	ND	ND	NM	ND	ND	ND	ND	ND	4.1	ND
	2021	ND	ND	ND	3.98	NM	ND	ND	0.4	ND	ND	ND	ND	ND	ND	3	ND	ND	ND	3.0	ND	ND	NM	ND	ND	0.3	ND
	720	ND	ND	ND	ND	7.14	ND	ND	4.9	ND	ND	ND	ND	ND	ND	5	0.17	ND	ND	ND	ND	ND	0.24	ND	ND	2.0	0.40
	721	ND	ND	ND	2.93	1.08	ND	ND	12.0	ND	ND	ND	ND	ND	ND	109	ND	ND	ND	11.3	ND	ND	NM	ND	ND	0.9	ND
	741C20	ND	0.51	0.01	NM	NM	0.01	ND	10.2	ND	ND	ND	0.002	ND	ND	33	7.50	0.00	0.01	NM	ND	0.96	0.71	0.02	0.0028	62.8	2.54
	741C21	ND	0.12	0.01	NM	NM	0.01	ND	16.6	ND	ND	ND	0.004	0.005	ND	462	0.53	0.03	0.01	NM	ND	2.41	0.61	0.19	0.0223	152.5	2.74
	753	0.40	ND	ND	NM	NM	ND	ND	1.9	ND	ND	ND	ND	ND	ND	52	0.28	ND	ND	NM	ND	0.92	NM	0.26	ND	6.2	2.20
	756	ND	ND	ND	NM	NM	ND	ND	325	ND	ND	ND	ND	ND	ND	17	ND	ND	ND	NM	ND	1.12	ND	0.22	ND	ND	ND
	759	ND	ND	ND	NM	NM	ND	ND	157	ND	ND	ND	ND	ND	ND	1119	ND	ND	ND	NM	ND	ND	ND	ND	ND	ND	ND
	760	ND	ND	ND	NM	NM	ND	ND	177	ND	ND	ND	ND	ND	ND	144	ND	ND	ND	NM	ND	ND	ND	ND	ND	ND	ND
	761	ND	ND	ND	NM	NM	ND	ND	13	ND	ND	ND	ND	ND	ND	99	ND	ND	ND	NM	ND	ND	ND	ND	ND	ND	ND
	767	ND	ND	ND	ND	ND	ND	ND	1	ND	ND	ND	ND	ND	ND	0.5	0.03	NM	NM	5.5	ND	0.48	0.05	ND	ND	0.9	0.11
	818	ND	0.40	ND	NM	NM	ND	ND	91	ND	ND	ND	ND	ND	ND	108	ND	ND	ND	NM	ND	16.05	ND	0.46	ND	**852**	ND
	822	ND	ND	ND	NM	NM	ND	ND	189	ND	ND	ND	ND	ND	ND	10	ND	ND	ND	NM	ND	1.08	ND	ND	ND	6.9	ND
	828	0.16	ND	ND	NM	NM	ND	ND	7	ND	ND	ND	ND	ND	ND	54	0.61	ND	ND	NM	ND	0.53	0.24	ND	ND	6.5	0.63
	833	ND	ND	ND	ND	NM	ND	ND	256	ND	ND	ND	ND	ND	ND	69	ND	ND	ND	23	ND	ND	ND	ND	ND	5.6	ND
	836	0.27	ND	ND	NM	NM	ND	ND	69	ND	ND	ND	ND	ND	ND	18	0.20	ND	ND	NM	ND	3.04	0.31	0.13	ND	4.0	0.68
	843	ND	1.01	0.12	NM	NM	0.21	0.20	ND	ND	ND	ND	ND	ND	ND	9	NM	0.27	1.19	NM	ND	12.25	NM	2.36	ND	ND	NM
	910	ND	ND	ND	22.11	ND	ND	ND	14	ND	ND	ND	ND	ND	ND	7	ND	ND	0.23	113	ND	0.60	NM	0.44	ND	11.0	4.63
	MERCK	ND	ND	ND	NM	NM	ND	ND	5.1	ND	ND	ND	ND	ND	ND	24	ND	ND	ND	NM	ND	ND	NM	ND	ND	3.7	ND
Number of Detect Test Conditions		3	6	4	4	3	4	2	22	1	0	0	2	2	1	26	9	5	6	6	1	14	6	11	5	21	9

Table 5-3: Hazardous Organic Emissions from Hazardous Waste Boilers for Compounds for Which Emissions Data for Oil-Fired Industrial Boiler Are Available

5.1.3 Exceedances of Industrial Boiler Benchmark

The 173 hazardous waste boiler emissions conditions were compared to an industrial boiler benchmark for each compound--the 95%ile test condition average level from the industrial boiler data base. There are 32 exceedances of the benchmark level from 19 boilers. Twelve of these exceedances involved dichloromethane (methylene chloride) and seven involved benzene.

The results are summarized in Table 5-4. For many exceedances, the test report indicates that the sample may have been contaminated. This was a particular problem for dichloromethane. Lab contamination was known or thought to be a problem for 15 of the exceedances. For ten cases (seven with dichloromethane, two with benzene, and one with toluene) the constituent being measured was found in the blank. There were five additional exceedances for dichloromethane, a common lab contaminant that is frequently found in laboratory samples and in the environment.[58]

Eleven other exceedances were at *de minimis* emission levels. Hazardous waste boiler emissions were below 8 ug/dscm for benzo(a)anthracene, benzo[a]pyrene, ethylbenzene (accounting for four exceedances), 2-methylnaphthalene, anthracene, fluorine (accounting for two exceedances), and phenathrene.

Moreover, we note that only six of the 19 boilers had exceedances that were not suspect because of known or suspected lab contamination and that were at significant concentration levels. Five of the exceedances were for benzene and one was for acetaldehyde. One of the benzene exceedances was a *de minimis* exceedance at an emission level of 91 ug/dscm compared to the oil emissions benchmark of 90 ug/dscm. In addition, none of the other five boilers were operating under the conditions that would be required for ECF boilers. Although this is not unexpected because these boilers were not required to operate under those conditions, operating under combustion conditions less stringent than would required for ECF boilers could result in higher organic emissions. Three of these boilers burned hazardous waste fuel with a heating value of 2,000 Btu/lb or below while ECF must have an as-fired heating value of 8,000 Btu/lb. One boiler fired less than 20% primary fuel (natural gas) while ECF must be fired with at least 50% primary fuel. And, the hazardous waste fired in one boiler had virtually no heat content and had a viscosity of 165 cs, while ECF must have an as-fired viscosity of 50 cs.

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[58] http://www.atsdr.cdc.gov/toxprofiles/tp14-c6.pdf

Source	Cond ID	Company	City	State	Compound	Industrial Oil-Fired Boilers			HW Boiler	Comment
						95th Percentile (ug/dscm)	Max (ug/dscm)	# Test Conditions w/ Detects	Cond Avg (ug/dscm)	
721	721C12	Celanese	Bay City	TX	Dichloromethane	40	41	2	109	Dichloromethane is a common lab contaminant. Unclear if primary fuel is natural gas or vent gas; One waste has only 6,300 Btu/lb.
741	741C20	Rohm and Haas	Louisvillle	KY	Ethylbenzene	0.48	0.49	2	7.5	HW Boiler emissions at *de minimis* levels. Fossil fuel firing rate estimated < 45%. Napthalene was spiked at levels higher than in fuel oil (and the CF spec) and may have contributed to ethylbenzene emissions. Only 2 fuel oil emissions test conditions are available --may not be representative.
	741C21				Dichloromethane	40	41	2	462	Boiler load only 25%. Dichloromethane in blank. Dichoromethane is a common lab contaminant.
					Ethylbenzene	0.48	0.49	2	0.52	HW Boiler emissions at *de minimis* levels. Boiler load only 25%.
753	753C10	Union Carbide	Hahnville	LA	Dichloromethane	40	41	2	52	Dichloromethane in blank. Facility no longer burning HW.
756	756C10	DSM Copolymer Inc.	Addis	LA	Benzene	90	158	12	325	Benzene in blank. Benzene during natural gas baseline test was 240 ug/dscm. Unit closed.
759	759C3	Dupont/Invista	Orange	TX	Dichloromethane	40	41	2	1120	Dichloromethane in blank. One waste has a HV only 1400 Btu/lb.
					Benzene	90	158	12	157	HW Emissions comparable with industrial boiler max. One waste had HV of only 1400 Btu/lb.
760	760C4	Dupont/Invista	Orange	TX	Dichloromethane	40	41	2	144	One waste has HV of only 2,000 Btu/lb. Dichloromethane is a common lab contaminant.
					Benzene	90	158	12	177	One waste had HV of only 2,000 Btu/lb.
761	761C5	Dupont/Invista	Orange	TX	Dichloromethane	40	41	2	99	Test report notes that dichloromethane is a common lab contaminant.
818	818C10	Westvaco	DeRidder	LA	Dichloromethane	40	41	2	108	Dichloromethane in blank; Dichloromethane at 230 ug/dscm in natural gas baseline test.
					Benzene	90	158	12	91	HW boiler emissions only fractionally above benchmark and well below oil-fired boiler max.
					Toluene	233	348	11	852	Toluene in blank.
822	822C2	Exxon Chemical Co.	Baton Rouge	LA	Benzene	90	158	12	189	Benzene in blank. Estimated < 25% natural gas during test.
828	828C10	Angus Chemical	Sterlington	LA	Dichloromethane	40	41	2	54	Test report states that dichoromethane emissions seen are likely due to contaminants.
					Ethylbenzene	0.48	0.49	2	0.61	HW Boiler emissions at *de minimis* levels. Oil-fired boiler data may not be representative-- data from only two test conditions are available
833	833C12	BASF	Freeport	TX	Dichloromethane	40	41	2	69	Dichloromethane in blank, One wastestream had HV of only ~1000 Btu/lb.
					Benzene	90	158	12	256	One wastestream has a HV of only ~1000 Btu/lb.
843	843C3	Dow Chemical Company	Freeport	TX	2-Methylnaphthalene	0.7	1.1	11	1.0	HW emissions at *de minimis* levels and below fuel oil max of 1.4 ug/dscm. Natural gas firing rate only ~30%; Boiler load only ~30%.
					Anthracene	0.06	0.08	8	0.21	HW emissions at *de minimis* levels. HW Boiler natural gas firing rate only ~30%; Boiler load only ~
					Benz(a)anthracene	0.16	0.16	4	0.20	HW boiler emissions at *de minimis* levels. HW Boiler natural gas firing rate only ~30%; Boiler load only ~30%.
					Fluorene	0.22	0.52	15	1.19	HW boiler emissions at *de minimis* levels. HW Boiler natural gas firing rate only ~30%; Boiler load only ~30%.
					Phenanthrene	0.92	1.6	20	2.4	HW boiler emissions at *de minimis* levels. HW Boiler natural gas firing rate only ~30%; Boiler load only ~30%.
910	910C3	Union Carbide	Texas City	TX	Fluorene	0.22	0.52	15	0.23	HW Boiler emissions at *de minimis* levels and well below industrial boiler max. Facility no longer burning HW.
1018	1018C12	Celanese Ltd	Bishop	TX	Acetaldehyde	66	68	2	100	HW Boiler fired < 20% fossil fuel. Below 95th percentile for natural gas boilers. Only 2 test conditions available from oil-fired boilers--may not be representative.
2007	2007C20	Air Products Manufacturing	Wichita	KS	Benzo[a]pyrene	0.005	0.005	1	0.011	HW Boiler emissions at *de minimis* levels. Only one oil-fired boiler run for a benchmark; does not represent the range for oil-fired boilers
2008	2008C20	Sunoco	Philadelphia	PA	Ethylbenzene	0.48	0.49	2	2.34	HW Boiler emissions at *de minimis* levels. HW Boiler fired 100% waste w/ viscosity of > 80 cS. Boiler load only ~25%.
2012	2012C2	Dupont/Invista	Victoria	TX	Dichloromethane	40	41	2	76	Dichloromethane in blank. Natural gas firing rate only ~40%.
2013	2013C4	Dupont/Invista	Victoria	TX	Dichloromethane	40	41	2	58	Dichloromethane in blank. One waste has very high viscosity--165 cs; One waste has virtually no heat content.
					Benzene	90	158	12	193	One waste has very high viscosity--165 cs; Another has virtually no heat content.
2016	2016C2	Dupont/Invista	Victoria	TX	Dichloromethane	40	41	2	50	Dichloromethane is a common lab contaminant. Unclear if any fossil fuel was fed.

Table 5-4: Comparison of Organic Emissions from Industrial Boilers and Oil- Fired Industrial Boilers: Summary of Exceedences

5.1.4 Nondetect Analysis—Limitations of the Database

As Table 5-3 indicated, hazardous organic emissions were nondetect for a majority of compounds for several of the hazardous waste boilers. Appendix B summarizes these nondetect data and compares detection limits to the industrial boiler benchmark. For several compounds, detection limits were higher than the industrial boiler benchmark for a significant fraction of the boilers. In instances where the detection limits exceed the benchmark level, the actual emissions level from the hazardous waste boiler may or may not be higher than the benchmark level.

5.1.5 Emissions of Other Hazardous Organics from Hazardous Waste Boilers

In addition to the 26 organic compounds with available emissions data from oil-fired industrial boilers, we also extracted detect data from 40 other hazardous organics emitted by the hazardous waste boilers.[59] Table 5-5 shows the average emissions from hazardous waste boilers for these hazardous organics. Test condition average emissions are at *de minimis* levels—below 10 ug/dscm—for all compounds except acetophenone, phenol, bis(2-ethylhexyl)phthalate, and chloroform.

All four of these compounds had a single test condition which appeared to be a high outlier. Therefore we conducted a statistical outlier analysis for the data sets for these compounds. The analysis involved: (a) identifying the suspected outlier, (b) assessing if the remaining data fit either a normal or lognormal distribution using the Shapiro-Wilk test procedure, and (c) using the Dixon and Grubbs statistical tests to assess if the suspected data point is an outlier.

This process, which is detailed in Appendix C, determined that the test condition with the highest emissions average was an outlier for acetophenone and phenol. As seen in the far right column of Table 5-5, the average emissions for these two compounds are below 5 ug/dscm without the statistical outlier. As explained below, the highest test condition average was not a statistical outlier for the other two compounds: bis(2-ethylhexyl)phthalate and chloroform.

We have bis(2-ethylhexyl)phthalate emissions data for 15 test conditions (each generally comprised of three runs) representing 15 different boilers. Test condition average emissions ranged from 0.34 ug/dscm to 600 ug/dscm for the boilers, with an average of 69 ug/dscm. Although the highest test condition average—600 ug/dscm—appeared to be an outlier given that the second highest average was 130 ug/dscm and 12 test conditions were below 42 ug/dscm, we determined that it is not a statistical outlier.[60] Nonetheless, we note that: (1) the boiler with the highest emissions—600 ug/dscm—was not operating under the conditions that would be required for an ECF boiler (which could result in higher emissions)—the primary fuel firing rata was approximately 30% rather than a minimum of 50%, and boiler load was approximately 30% rather than a minimum of 40%; and (2) bis(2-ethylhexyl)phthalate is known to be a common lab contaminant, and thus the reported emissions levels may be suspect.

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[59] For these compounds we did not extract partial detects.

[60] See Appendix C

For chloroform, we have emissions data for 9 test conditions (each generally comprised of three runs) representing 9 different boilers. Test condition average emissions ranged from 0.28 ug/dscm to 270 ug/dscm for the boilers, with an average of 45 ug/dscm. Although the highest test condition average—270 ug/dscm—appeared to be an outlier given that the second highest average was 85 ug/dscm and the remaining test conditions did not exceed 16 ug/dscm, we determined that it is not a statistical outlier. We note, however, that the boiler with the highest emissions—270 ug/dscm—was not operating under the conditions that would be required for an ECF boiler—it burned a waste fuel with a heating value below 8,000 Btu/lb, and it is not clear whether the boiler burned process vent gas or natural gas as primary fuel.

Compound	CAS Number	No. of Boilers with data	No. of Test Conditions	No. of Detect Runs	Emissions (ug/dscm @ 7% O_2)		
					Average Emiss by test condition	Average Emiss by run	Avg Emiss by test cond w/o outliers[1]
1,1-Dichloroethene	75-35-4	1	1	2	0.7	0.7	
1,2,4-Trichlorobenzene	120-82-1	1	1	2	0.5	0.5	
1,2-Dichloroethane	107-06-2	1	1	3	2.4	2.4	
1,2-Diphenylhydrazine	122-66-7	1	1	3	0.8	0.8	
1,4-Dichlorobenzene	106-46-7	3	3	5	6.3	11	
2-Chloroacetophenone	532-27-4	1	1	1	3.9	3.9	
2,4,6-Trichlorophenol	88-06-2	1	1	1	0.2	0.2	
2-Butanone (MEK)	78-93-3	3	3	14	5.5	6.6	
2-Butenal	4170-30-3	2	2	3	1.1	5.9	
4-Chloro-3-methylphenol	59-50-7	2	2	5	1.7	1.6	
4-Methylphenol (p-cresol)	106-44-5	1	1	2	1.3	1.3	
4-Nitrophenol	100-02-7	1	1	3	2.0	2.0	
Acetophenone	98-86-2	6	6	15	85	105	4.0
bis(2-Ethylhexyl)phthalate	117-81-7	15	15	36	69	47	
Bromomethane	74-83-9	5	5	11	2.6	2.2	
Butylbenzylphthalate	85-68-7	8	8	18	3.5	3.6	
Carbon Disulfide	75-15-0	4	4	10	5.1	6.1	
Carbon tetrachloride	56-23-5	2	2	4	3.3	3.3	
Chlorobenzene	108-90-7	3	3	6	2.7	2.6	
Chloroethane	75-00-3	2	2	3	5.4	5.1	
Chloroform	67-66-3	9	9	23	45	44	
Chloromethane	74-87-3	5	5	13	6.6	6.6	
Crotonaldehyde	123-73-9	1	1	3	6.1	6.1	
Cumene	98-82-8	2	2	4	2.9	2.1	
Dichlorodifluoromethane	75-71-8	1	1	3	2.5	2.5	
Diethylphthalate	84-66-2	13	13	33	2.3	1.7	
Di-n-butylphthalate	84-74-2	10	10	27	5.6	3.9	
Di-n-octyl phthalate	117-84-0	3	3	3	0.4	0.4	
Diphenylamine	122-39-4	1	1	1	0.3	0.3	
Hexachlorobutadiene	87-68-3	1	1	1	0.2	0.2	
Iodomethane	74-88-4	1	1	3	0.3	0.3	
o-Cresol (2-methyl phenol)	95-48-7	5	5	14	2.8	2.9	
Phenol	108-95-2	5	5	12	30	37	3.9
Propanal (Propionaldehyde)	123-38-6	5	5	13	9.2	10	
Styrene	100-42-5	6	6	12	1.0	0.9	
Tetrachloroethene	127-18-4	2	2	4	1.5	0.8	
Trichloroethene	79-01-6	1	1	1	0.2	0.2	
Vinyl acetate	108-05-4	1	1	2	0.7	0.7	
Vinyl Chloride	75-01-4	1	1	1	2.8	2.8	
Trichlorofluoromethane	75-69-4	6	6	13	9.3	9.3	

[1] Values in this column are without 3 runs from test condition 843C3 for acetophenone, and phenol. These conditions were determined to be statistical outliers.

Table 5-5: Hazardous Organic Emissions from Hazardous Waste Boilers for Compounds for which Emissions Data for Oil-Fired Industrial Boiler Are Not Available

5.2 Dioxins and Furan (PCDD/F)

Given that polychlorinated dibenzo dioxins and furans (PCDD/F), like other persistant organic pollutants (POPS), bioaccumulate in human and animal fatty tissue and remain in the environment for long periods, they merit special consideration when expansion of the comparable fuels exclusion is being considered. This section contains a summary of PCDD/F/furan formation mechanisms and discusses available PCDD/F emissions data from boilers that burn hazardous waste. Additionally, the results of an abbreviated risk assessment for PCDD/F is also presented.

5.2.1 PCDD/F Formation Mechanisms

This section provides a brief summary of formation mechanisms for PCDD/F. Note that several extensive reviews of PCDD/F formation mechanisms are available.[61, 62] The primary formation mechanisms can be described as:

1. Homogeneous (gas-gas) formation from organic precursors (such as chlorinated aromatics) in combustion zone (500-800 °C).
2. Heterogeneous (gas-solid) condensation reactions between gas phase precursors and a catalytic particle surface.
3. De novo synthesis- Heterogeneous surface-catalyzed reactions between carbon containing particles and organic or inorganic chlorine.

Mechanism (1) usually plays a minor role in PCCD/F formation in combustion facilities, although it has been theorized that gas-phase formation of Cl_2 leads to PCDD/F formation when a highly chlorinated waste is burned and the combustion gases undergo slow quench (e.g., in a waste heat boiler).

Mechanisms (2) and (3) are generally more dominant. The key requirements of PCDD/F formation by these two pathways are particulate holdup in the temperature window 200-400 °C (400-750 °F), and the presence of chlorine or chlorinated organics. Although it is not always easy to distinguish between mechanisms (2) and (3), according to work cited in the EPA risk burn guidance document mechanism (2) involves fast reactions and may predominate in post-combustion and heat exchanger sections where residence time at the critical temperature window may on the order of 1 second. Conversely, the de novo process may dominate in dry APCDs where particle residence times may be much longer.

Other factors – The bulk of the chlorine in a combustor would be present as either HCl or Cl_2. HCl is converted to Cl_2 via the Deacon reaction and Cl_2 is known to chlorinate aromatic organic PCDD/F precursors. The presence of metal catalysts (such as copper or nickel) are usually required to overcome kinetic limitations of the Deacon reaction. Additionally, metals support the condensation reactions that form PCDD/Fs from organic

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[61] USEPA "Risk Burn Guidance for Hazardous Waste Combustion Factilities", EPA OSW/Region 4, EPA 530-3-01-001, 2001

[62] USEPA, "Technical Support Document for HWC MACT Standards," September 2005, Vol; IV Compliance with the HWC MACT Standards, Section 3.

precursors. Also, the presence of sulfur inhibits formation of PCDD/F by depleting Cl_2 and poisoning copper catalysts.

As shown in a comprehensive review by Stanmore,[63] numerous PCCD/F formation pathways have been studied and documented. Many of these pathways involve the formation or presence of chlorinated benzene or phenol. However, if an alternative chlorine source is present, precursors can be nonchlorinated aromatics (such as benzene) or even aliphatics such as propene or acetaldehyde. Gullet and Seeker[64] have shown that heterogeneous PCCD/F formation pathways from aliphatics involve PAHs as an intermediate step. Procaccini et al showed by injection of benzene into a cooldown section of a combustor (at 500-800°C) that chlorobenzenes and chlorophenols may be rapidly formed. [65] (Note that, for this scenario to occur in a real boiler, significant amounts of benzene would have to escape the flame zone).

5.2.2 Factors influencing PCDD/F Emissions from ECF Fired Boilers

1. As noted in the previous section, PAH are intermediate compounds under certain PCDD/F formation pathways. [66] ECF will not contain detect levels of PAH because, as discussed earlier, the specifications for PAH hydrocarbons would continue to apply under the proposed ECF exclusion.
2. Many of the 26 hydrocarbons and oxygenates for which the specifications would not apply are aromatics (e.g., benzene, toluene, phenol). In the presence of chlorine, these can be converted to known PCDD/F precursors such as chlorobenzenes and chlorophenols. (Note that the current 540 mg/kg specification limit on total chlorine is more than sufficient chlorine for PCDD/F formation.)
3. All the mechanisms mentioned above require chlorine in the feed. The heterogeneous mechanisms are largely impacted by metals. Although specifications for total chlorine as well as individual halogenated organics would apply to ECF (see Table 1 to §261.38), there would be more than sufficient chlorine for PCDD/F formation, as mentioned above. Also, although the metals specifications in Table 1 to §261.38 would apply to ECF and thus would limit nickel levels, there is no specification for copper. Thus, there may be metals in ECF that could catalyze heterogenous PCDD/F formation reactions across an ESP or FF.
4. PCCD/F formed in the combustion zone via homogeneous gas phase reactions will likely be destroyed in the combustion zone. The Dellinger thermal stability index ranks 2,3,7,8 TCDD (the PCDD/F congener with the highest TEQ) a Class

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[63] Stanmore B.R., 2004,"The Formation of Dioxins in Combustion Systems," Combustion and Flame, v 36, pp398-427.

[64] Gullet B., and Seeker, R., 1997, "Chlorinated Dioxin and Furan Formation, Control and Monitoring", ICCR Meeting Presentation

[65] Procaccini et al, 2003 "Formation of Chlorinated Aromatics by Reactions of $Cl^{\cdot}$, Cl_2, and HCl with Benzene in the Cool-Down Zone of a Combustor" Engineering Science and Technology, v .37 p, pp 1684-1689.

[66] http://www.atsdr.cdc.gov/toxprofiles/tp69.html

2 compound and thus easier to destroy than benzene. Similarly, aromatic hydrocarbons in the feed will be mostly destroyed in the combustion zone.

5. The additional requirement of the 100 ppmv CO limit would serve to establish good combustion conditions and minimize the formation of chlorinated aromatic PCDD/F precursors as PICs. Also, continuous CO monitoring would warn of flame quenching or other process upsets that could cause soot deposition in downstream boiler tubes and contribute to increased PCDD/F emissions.

In summary, we conclude that PCDD/F formed in the combustion zone by homogenous gas phase reactions will be destroyed under the good combustion conditions required for ECF boilers. However, there may be enough chlorine, and potentially, metal catalyst, present in ECF (or other boiler fuels) to promote heterogenous PCDD/F formation across an ESP or FF. We discuss below how we would address this concern.

Units with Dry Air Pollution Control Devices- For units with dry APCDs (i.e., ESP or FF), formation of surface-catalyzed PCDD/F can increase exponentially for APCD temperatures above 400 °F.[67] Additionally, the next section will show that hazardous waste burning boilers with dry APCD temperatures below 400 °F have comparatively lower emissions of PDD/F. Therefore a gas temperature limit of 400°F is proposed for boilers that burn ECF, unless the boiler's primary fuel is coal. Boilers that burn coal as the primary fuel are exempt from this requirement because sulfur in coal is known to inhibit PCDD/F formation.

5.2.3 PCDD/F Emissions from Boilers burning Hazardous Waste

Table 5-6 shows PCDD/F emissions data from hazardous waste burning boilers separated into three categories: (a) units with dry APCS; (b) units with wet APCS; and (c) units with no APCS or unknown APCS. The table shows condition average PCDD/F emissions in ng TEQ/dscm.

The table includes data from the 2005 Hazardous Waste Combustor MACT database. (which includes a few boilers that are no longer burning hazardous waste) and data from additional test reports obtained since the close of the HWC MACT database.

Data are available from 11 test conditions for dry APCD-equipped units. Two dry APCD boilers have PCDD/F emissions above 0.4 ng TEQ/dscm, the generic MACT standard for most HWCs, and a level below which D/F emissions are generally considered *de minimis*. One watertube boiler which had PCDD/F emissions of 2.4 ng TEQ/dscm is not of integral design (and thus would not be eligible to burn ECF) and had very high levels of nickel in the feed.[68] The second unit, a firetube boiler feeding mixed waste had emissions of 0.66 ng TEQ/dscm. Firetube boilers would not be eligible to burn ECF.

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[67] USEPA, "Technical Support Document for HWC MACT Standards, Vol IV, Compliance with HWC MACT Standards," September 2005, Section 3.2

[68] Nickel is known to increase PCDD/F formation. Nickel concentrations in the waste were substantially higher than would be allowed for ECF. See Table 1 to §261.38.

APCS	Source ID	Cond ID	Facility Name	State	FT Boiler?	Process Heater?	New[3] Report?	Avg APCD Temp (°F)	PCCD/F Emiss (ng TEQ/dscm @ 7% O2)
Dry APCS	763		Albemarle	SC	Yes	No	Y*	377	0.160
	763		Albemarle	SC	Yes	No	Y*	431	0.270
	771	771C20	Kalama Chemical (BF Goodrich)	WA	No	No	Y	315	0.015
	771	771C1	Kalama Chemical (BF Goodrich)	WA	No	No	N	324	0.013
	771	771C2	Kalama Chemical (BF Goodrich)	WA	No	No	N	319	0.008
	813	813C3	Rubicon, Inc.	LA	No	No	N	410	2.360
	818	818C13	Westvaco	LA	No	No	N		0.027
	1009[2]	1009C2	Eastman Chemicals Co. - Arkansas Eastman Div	AR	No	No	N	502	0.069
	901		DSSI	TN	Yes	No	Y*	232	0.055
	901		DSSI	TN	Yes	No	Y*	230	0.660
	901		DSSI	TN	Yes	No	Y*	232	0.004
Wet APCS	776		Nutrasweet	GA	Yes	No	Y*		0.140
	777		Nutrasweet	GA	Yes	No	Y*		1.370
	777		Nutrasweet	GA	Yes	No	Y*		1.330
	812	812C3	Rubicon, Inc	LA	No	No	N		0.355
	849[1]	849C5	Dow Chemical Company	TX			N		0.012
	2001	2001C3	Dow Chemical Co.	LA	Yes	No	N		0.435
	2002	2002C3	Dow Chemical Co.	LA	Yes	No	N		0.092
	2003	2003C3	Dow Chemical Co.	LA	Yes	No	N		0.021
	2020	2020C3	Dow Chemical Company	TX	Yes	No	N		0.118
No APCS	232	232C10	Solutia (Chocolate Bayou Plant)	TX	No	No	N		0.018
	232	232C11	Solutia (Chocolate Bayou Plant)	TX	No	No	N		0.003
	720	720C10	Celanese Ltd., Chemical Group Clear Lake Plant	TX	No	No	N		0.015
	721	721C12	Celanese Ltd	TX	No	No	N		0.004
	735	735C4	Reilly Industries, Inc.	IN	No	No	N		0.007
	735	735C3	Reilly Industries, Inc.	IN	No	No	N		0.006
	737	737C4	Reilly Industries, Inc.	IN	No	No	N		0.004
	737	737C3	Reilly Industries, Inc.	IN	No	No	N		0.018
	741	741C20	Rohm and Haas Company	KY	No	No	Y		0.009
	741	741C21	Rohm and Haas Company	KY	No	No	Y		0.007
	753[1]	753C10	Union Carbide Corp.	LA			N		0.008
	756[1]	756C10	DSM Copolymer Inc.	LA	No	No	N		0.033
	760	760C4	E.I. duPont de Nemours & Co., Inc.	TX	No	No	N		0.005
	761	761C5	E.I. duPont de Nemours & Co., Inc.	TX	No	No	N		0.002
	767	767C8	Goodyear Tire and Rubber Company	TX	No	No	N		0.000
	814	814C2	Rubicon, Inc	LA	No	Yes	N		0.072
	815	815C2	Rubicon, Inc	LA	No	Yes	N		0.040
	822	822C2	Exxon Chemical Co.	LA	No	No	N		0.030
	828	828C1	Angus Chemical Company	LA	No	No	N		0.095
	833	833C12	BASF Corporation	TX	No	No	N		0.007
	834	834C11	BASF	LA	No	No	N		0.008
	836	836C13	BASF	LA	No	No	N		0.036
	843	843C3	Dow Chemical Company	TX	No	No	N		0.004
	910[1]	910C3	Union Carbide Corporation	TX			N		0.005
	911	911C13	Sunoco Inc. (R&M) Haverhill Plant	OH	No	No	N		0.042
	1000	1000C20	Mallinckrodt Inc.	NC	No	No	Y		0.018
	1000	1000C21	Mallinckrodt Inc.	NC	No	No	Y		0.019
	1018	1018C12	Celanese Ltd	TX	No	No	N		0.007
	2000	2000C2	Georgia Gulf Chemicals and Vinyls, LLC.	LA	No	No	N		0.032
	2007	2007C20	Air Products Manufacturing Corp.	KS	No	No	Y		0.011
	2021	2021C3	Union Carbide Coporation	TX	No	No	N		0.033
	2008A	2008AC20	Sunoco Inc. (R & M) Frankford Plant	PA	No	No	Y		0.008
	2008A	2008AC21	Sunoco Inc. (R & M) Frankford Plant	PA	No	No	Y		0.005
	Merck	MerckC20	Merck & Co., Inc.	NJ	No	No	Y		0.008
	759	759C3	E.I. duPont de Nemours & Co., Inc.	TX	No	No	N		0.005
	2012	2012C2	E.I. Du Pont Nemours & Company, Inc.	TX	No	No	N		0.006
	2013	2013C4	E.I. Du Pont De Nemours & Company, Inc.	TX	No	No	N		0.032
	2016	2016C2	E.I. Du Pont De Nemours & Company, Inc.	TX	No	No	N		0.003

[1]- These units are shut down or are no longer burning hazardous waste

[2] This is the only Solud fuel fiired boiler on the list and has a stoker design

[3] Y*- Info received in 2004 from EPA Region 4, Y- Info from test reports collected in 2006

Table 5-6: PCDD/F Emissions from Hazardous Waste Boilers

We have nine test conditions for PCCD/F from units with wet APCDs. Two PCDD/Fs greater than 0.4 ng TEQ/dscm for three test conditions from two units. Both of these are fire tube units and one of them burns waste fuel containing 60% chlorine. Again, fire tube boilers would not be eligible to burn ECF.

We have 38 test conditions for PCDD/F from units without any APCDs. Test condition averages are all below 0.1 ngTEQ/dscm with an average emissions level of 0.02 ng TEQ/dscm.

5.2.4 Comparative Risk Assessment

Background: In 1999, EPA conducted a comprehensive, multi-pathway risk assessment for Phase I HWC (incinerators and kilns). For each facility, site-specific air modeling and fate and transport modeling was performed to quantify multi-pathway exposures. Risk distributions were developed for each source category and each pollutant. Since the 2005 HWC MACT replacement rule brought in additional source categories this analysis was updated for the 2005 rulemaking.[69] A comparative analysis was performed in lieu of a comprehensive risk assessment. The comparative analysis relied on predictions from the Phase I risk assessment and comparisons between the Phase I and Phase II universes. Two primary methodologies were utilized in the comparative analysis:

- Weight-of-Evidence (WOE) Scoring - WOE scoring relied on a large array of statistical comparisons involving all four megavariables (emissions rates, stack parameters, population and meteorology) to evaluate whether a Phase II source category would be expected to have risks either less than, equal to, or greater than a Phase I category's high-end risks for each pollutant.

- Margin of Exposure (MOE) Analysis - For situations where the WOE scoring predicted in the direction of Phase II risk greater than Phase I, a simple Phase II/Phase I emissions ratio was calculated (using upper confidence limit mass emission rates for a given pollutant). The emission ratio was then evaluated against the risk "safety margin" (i.e., MOE) determined from the Phase I risk assessment.

Comparative Risk Analysis: An abbreviated comparative risk evaluation was performed to assess the impact of the proposed comparable fuels expansion on PCDD/F emissions. The abbreviated evaluation utilized one component of the Phase II hazardous waste combustor MACT comparative risk evaluation, specifically, the Margin of Exposure (MOE) analysis. The emission-adjusted MOE analysis utilizes the risk "safety margins" (i.e., modeled MOEs) determined from the MACT Phase I comprehensive risk assessment to see whether, considering emissions alone, risks for a second universe (here,

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[69] RTI International, "Inferential Risk Analysis in Support of Standards for Emissions of Hazardous Air Pollutants from Hazardous Waste Combustors," Final Report, July 2005

the ECF boilers) could rise to a level of concern.[70] Smaller MOEs correspond to a greater potential for risk beyond the level of concern (i.e., 1E-05 lifetime cancer risk). To predict an emission-adjusted MOE for the ECF boilers, the Phase I modeled MOEs are multiplied by the PCDD/F emission ratios for the Phase I universe versus the ECF boiler universe. The Phase I incinerator category was used for predicting the boiler-adjusted MOEs. Since there are little or no PCDD/F emissions data specifically for the universe under consideration (i.e., industrial boilers burning emissions-comparable fuel), the PCDD/F emissions database from boilers burning hazardous waste fuels was considered as a surrogate

The technical approach involved the following steps:

1. Update/Revise boiler PCDD/F emissions data.
2. Calculate point estimates and confidence levels for revised boiler emissions data.
3. Combine old phase I and revised Phase II data sets and conduct test for common generalized percentile.
4. Adjust MOE if appropriate.

Update Boiler Database

PCDD/F emissions information available in the newly acquired test reports was added:

a) Mallinkrodt, Raleigh, NC (1000)
b) Rohm & Haas, Louisville, KY (741)
c) Air Products, Wichita, KS (2007)
d) Kalama Chemical, Kalama, WA (771)
e) Sunoco, Philadelphia, PA (2008)
f) Merck, Rahway, NJ

Since there are no PCDD/F data available from nonstoker solid fuel boilers, there were no revisions to the list based on inclusion of nonstoker solid fuel boilers.

Since firetube boilers and process heaters would not be permitted to burn ECF, these units were removed from the “Phase II boiler” list that was used for the MACT 2005 comparative risk assessment. Units 763 (SC), 776/777 (GA), 814/815 (LA), 2001/2/3 (TX), 1016(TX), 2020, 746(TX) were removed).[71]

Once the revisions were made to the database, the facility emissions estimates (in g TEQ/yr) were calculated. Note that, consistent with the approach used for the 2005 assessment, imputed data were used only in instances where at least one source at a given

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[70] It must be emphasized that emission-adjusted MOEs should not be construed as predictions of the level of risk. Instead, they are only intended to provide an indication of whether risks *could* exceed a level of concern based on simplifying assumptions and as such, are subject to a considerable degree of uncertainty

[71] Boilers that were not integrally designed were not excluded.

facility conducted emissions testing for PCDD/F. For the revised boiler databases there were 25 distinct facility observations (compared to 23 for the 2005 analysis).

Calculate Revised Point Estimates and Percentile levels for boilers

The point estimates and upper and lower confidence levels for the revised boiler category were calculated at the 90th, 75th, and 50th percentile levels and are shown in Appendix D.” The revised point source estimates in g TEQ/yr are:

90th	0.024
75th	0.016
50th	0.007

Common Generalized Percentile Test for Combined Data

The revised boiler database was combined with the unchanged old Phase I incinerator database. There are 47 total observations (note that number of Phase I incinerator observations (n) =22 and number of revised boiler observations (m_{new}) = 25). These emissions are ranked from lowest to highest and chi square analyses were performed to determine the appropriate percentile level for the MOE analysis. The procedure followed involved the following steps.

1. Select a percentile level (typically 90% is chosen).
2. Calculate the point source estimate (for the combined data sets) at the percentile level selected.
3. Calculate the number of observations above and below the value calculated in step 2 for each data set. (n1 is the number of Phase I incinerator observations less than or equal to the point source estimate and n2 is the number of observations higher than this value. The corresponding number of observations for boilers is m1 and m2)
4. Calculate the chi square statistic (X^2) which is a function of n1, n2, m1 and m2.

$$\chi^2 = \frac{\left[n_1 m_2 - n_2 m_1\right]^2 (n+m)}{nm(n_1+m_1)(n_2+m_2)}$$

5. If X^2 is less than the critical level of 2.707 and one of the four quandrants (n1, n2, m1 and m2) is less than 5 we would move on to another percentile level closer to the median. However, if X^2 greater than 2.707 an adjustment of MOEs is warranted.

Test at 90th Percentile

The 90th percentile pt, is the 43rd ranked observation = 0.083 gTEQ/yr

n1 = # of Ph I INC observations that are less than or equal to 0.083 = 19
and n2= # of Ph I INC observations that are greater than 0.083 = 22-19=3

Similarly for the revised boiler set, m1= 24 and m2=1

Using the equation above we get $X^2 = 1.395$

And "p value" = Chidist(X^2 , 1) = 0.237

Since "pvalue" > 0.1 (equivalent to $X^2 < 2.707$) and two of the four quadrants (m1,m2,n1,n2) are less than 5 we move to a different percentile level closer to the median.

Test at 75th Percentile

Thus 75th percentile pt, is 36th ranked observation = 0.024 gTEQ/yr

We also have n1 =13 and n2= 9 as well as m1= 23 and m2=2

We calculate the chi square statistic

$X^2 = 7.069$

And "p value" = Chidist(X^2 , 1) = 0.0078

We now have the chi square statistic greater than the critical value of 2.707 so an adjustment to the MOEs warranted.

Adjusted Margin of Exposure

The original MOE for Phase I incinerators (using the 1985 D/F slope factor) are 50, 20 and 10 at the 90th, 95th and 99th percentile risk distributions respectively. These MOEs are adjusted by the upper confidence level emissions ratio at 75th percentile (i.e. Ph I UCL/Ph. II UCL= 0.166/0.062 =2.67).

The results are shown in Table 5-7. Appendix E presents detailed calculations.

	Phase I Modeled MOEs for 90th to 99th Percentile Risk Distributions			
Phase I - All Incinerators Complying w/ MACT		90th Percentile	95th Percentile	99th Percentile
- 1985 Dioxin Slope Factor		50	20	10
- 2003 Dioxin Slope Factor		8	4	1.7
	PCDD/F Emissions Rates (g TEQ/year)			
	75th Percentile Point Estimate	**95th Percent Confidence Bounds**		**Maximum**
		Upper	**Lower**	
Phase I All Incinerators	0.063	**0.166**	0.021	0.174
ECF Boilers	0.016	**0.062**	0.008	0.109
	ECF Predicted MOEs for 90th to 99th Percentile Risk Distributions			
ECF Boilers - 1985 Dioxin Slope Factor		90th Percentile	95th Percentile	99th Percentile
		130	**50**	**30**

Table 5-7: Results of Abbreviated Comparative PCDD/F Risk Assessment

Conclusions

1. The emissions-adjusted MOEs representing the ECF boilers are 130, 50 and 30 at the 90th, 95th, and 99th percentile risk distributions, respectively. This suggests a lower potential for risk for the ECF boiler category compared to the Phase I incinerator category.

2. The emission-adjusted MOE analysis should be considered a rough gauge of protectiveness. It is important to be aware of the potential error and uncertainty associated with this approach. Based on the cross-validation analysis conducted for the Phase II MACT evaluation (see Attachment 1), it would not be unusual (on the order of 33% of the time) to have predictive errors that are *greater* than an order of magnitude.

3. The emissions database itself is subject to substantial uncertainty. There are little or no PCDD/F emissions data specifically for the universe under consideration (i.e., industrial boilers burning ECF under the proposed design and operating conditions). Therefore, the PCDD/F emissions database from boilers burning hazardous waste fuels was considered as a surrogate. The surrogate emissions database may not be representative for some situations. For example, if the industrial boilers burning ECF were not required to control inlet temperature to

dry air pollution control devices, then PCDD/F emissions could be much higher than measured for the hazardous waste boilers.[72] Similarly, PCDD/Fs could be higher if the industrial boilers were permitted to burn ECF containing PAHs.[73] Other differences might include combustion quality and stack characteristics.

4. Use of the MOE analysis alone introduces greater uncertainty than for the MACT Phase II comparative risk evaluation. An important aspect of the Phase II comparative evaluation was that the statistical analyses, hypothesis testing, and WOE scoring *preceded* the MOE analysis. Only when the hypothesis testing/WOE scoring indicated the potential for increased risks (relative to the Phase I source category) did the MOE analysis come into play. Ideally, differences in stack parameters, location, nearby land use and meteorology should be taken into account in any evaluation of protectiveness.[74] Nevertheless, in the absence of additional information, an argument in favor of using the MOE component is that the cross-validation analysis showed MOE to err on the side of wrongly predicting greater risk.

5. EPA has been conducting a reassessment of the human health risk associated with dioxin and dioxin-like compounds (U.S. EPA , Exposure and Human Health Reassessment of 2,3,7,8-Tetrachlorodibenzo-p-Dioxin (TCDD) and Related Compounds, NAS Review Draft, December 2003). This draft reassessment was reviewed by the National Academy of Sciences (NAS) and EPA is currently evaluating the NAS report to determine next steps. Because this is still a draft report, the toxicity risk factors presented in this document should not be considered EPA's official estimates of dioxin toxicity but rather reflect EPA's ongoing effort to reevaluate dioxin toxicity. Evidence compiled from this draft reassessment indicates that the carcinogenic effects of dioxin and dioxin-like compounds may be six times as great as believed in 1985. However, given the emission-adjusted MOEs representing the ECF boilers, risks above the 1E-05 level of concern would not be predicted were the 2003 dioxin slope factor utilized for the risk management decision. An assessment using this alternative value should not be considered Agency policy.

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[72] Industrial boilers with dry air pollution control devices that elect to burn ECF would be required to control their air pollution control device inlet temperatures to 400 °F, unless their primary fuel is coal.

[73] The specifications in Table 1 to §261.38 would continue to apply to PAHs.

[74] We note, however, that there is no reason to believe that these parameters (e.g., stack parameters, location, nearby land use) would be any different for the universe of ECF boilers than for the universe of MACT HW boilers.

6 Special Conditions for Emission-Comparable Fuel

This section summarizes the conditions applicable to generators that claim the ECF exclusion and to ECF burners. For more information, see the preamble to the proposed rule, Part Two: Rationale for the Proposed Rule

ECF would be subject to all of the conditions that apply to existing comparable fuel, including

1. Constituent specifications in Table 1 to §261.38 with the exception of 26 hydrocarbons& oxygenates for which the specifications would not apply.
2. Minimum heating value of 5,000 Btu/lb, as-generated, and maximum viscosity of 50 cs, as-fired.
3. Prohibition on blending to meet the specifications.[75]
4. Notifications to state RCRA and CAA directors and public notification (see proposed §261.38(b)(2)
5. Waste analysis plans for generators and burners (see proposed §261.38 (b) (4) and (5)
6. Sampling and analysis conditions per proposed § 261.38(b)(6)
7. Prohibition on speculative accumulation (proposed § 261.38 b(7))
8. Recordkeeping (proposed § 261.38 (b)(8) and (9)
9. Burner Certification to generator per proposed §261.38 b(10), and
10. Ineligible waste codes.

However, ECF must also meet additional conditions to ensure that:

- It is stored and handled in a manner protective of human health and the environment given the higher concentrations of particular hazardous, volatile hydrocarbons and oxygenates it may contain compared to fuel oil; and
- It is burned under good combustion conditions that would ensure that emissions are comparable to emissions from fuel-oil combustion.

6.1 Storage of Emissions-Comparable-Fuels

Storage conditions for ECF are provided in §261.38 (c) (1) of the proposed rule. ECF must be stored in tanks (above ground or underground), tank cars or tank trucks.[76]

6.1.1 Above-Ground Storage Tanks

ECF stored in above ground tanks would be subject to: (a) certain SPCC provisions of 40 CFR Part 112 pertaining to the SPCC Plan; (b) secondary containment and release detection provisions; (c) preparedness and prevention, emergency procedures and response to releases provisions; and (d) air emissions

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[75] Generators may blend hazardous waste fuels to meet the viscosity specification under conditions provided by proposed §216.38 (a)(4).

[76] EPA is seeking comment if storage in other containers (such as 55 gallon drums and other portable containers) is likely to occur.

provisions adopted from the Organic Liquids Distribution NESHAP (Part 63, Subpart EEEE).

For a discussion of the proposed storage conditions, see discussion in Part Two, Section IV.A.1 of the preamble to the proposed rule.

6.1.2 Underground Storage Tanks

Underground storage tank systems managing ECF would be subject to the requirements under 40 CFR Part 280. These regulations include requirements for secondary containment,[77] leak detection, spill and overfill protection and corrosion protection.

6.2 Combustion of Emissions-Comparable Fuel

6.2.1 Combustor Type

As prescribed in the proposed rule at §261.38(c)(2)(i), ECF must be burned in a industrial or utility boiler. Additionally, the boiler must be a watertube, steam boiler that is not a stoker.

Combustion in firetube boilers or stokers would not be allowed. Firetube boilers are smaller and have a relatively higher surface to volume ratio which makes for colder burner temperatures due to higher heat loss. Therefore, there may be a greater potential for localized cold spots and poorly mixed zones which can result in poor combustion conditions. This is also true for stokers because they burn fuel with large particle size. Also, stokers in general have relatively higher emissions of CO and organics, evidence of less than optimum combustion conditions.

Burning of ECF would not be allowed in process heaters either because process heaters often have operating practices (such as quenching combustion gases to avoid overheating a process liquid) that could reduce combustion efficiency and result in higher emissions of PICs.

Also, ECF boilers must be industrial or utility boilers as defined in proposed §261.38(b)(2)(i)(B). ECF could not be burned in commercial or institutional boilers (e.g., boilers at hospitals, schools) for the same reasons that existing comparable fuel cannot be burned in those units. See 63 FR at 33798. Burning in industrial or utility boilers would ensure that ECF was burned in a unit subject to Federal/State/local air emission regulations and that was capable of handling excluded fuel (and, for ECF, was capable of complying with the conditions on burning ECF).

6.2.2 Operating Conditions

The burning of ECF must be conducted under boiler operating conditions that ensure a hot stable flame and are consistent with good combustion practices. These conditions include:[78]

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[77] The hydrocarbons and oxygenates for which the specifications would not apply for ECF are listed as hazardous substances in 40 CFR 302.4. Consequently, all ECF UST would be subject to the secondary containment and leak detection requirements of §280.42.

[78] See proposed rule at §261.38(c) (2)(ii) for complete specifications and see the preamble to the proposed rule, Part Two, Section II.B, for a discussion of the rationale for these conditions.

1. **Fossil fuel as primary fuel**. A minimum of 50% percent of fuel fired to the device must be fossil fuel, fuels derived from fossil fuel or tall oil. The 50% primary fuel firing rate must be determined on a total heat or volume input basis, whichever results in the greater volume of primary fuel fired;
2. **Fuel heating value**. Primary fuels and emission-comparable fuel must have a minimum as-fired heating value of 8,000 Btu/lb, and each material fired in a firing nozzle where ECF is fired must have a heating value of at least 8,000 Btu/lb, as-fired;
3. **CO CEMS.** When burning ECF, carbon monoxide emissions must not exceed 100 parts per million by volume, over an hourly rolling average (monitored continuously with a continuous emissions monitoring system (CEMS)), dry basis and corrected to 7 percent oxygen.[79]
4. **Dioxin/furan control.** Boilers equipped with a dry air pollution control device must monitor the combustion gas temperature at the inlet to the initial dry particulate matter control device, and the gas temperature must not exceed 400°F on an hourly rolling average. As discussed in Section 5.3.1 above, heterogeneous surface-catalyzed formation of PCDD/F is increased at temperatures above 400 °F. Note that the temperature limit is not required for boilers firing coal as primary fuel because sulfur in coal is known to inhibit formation of dioxins and furans.
5. **Automatic fuel cutoff system**. The boiler must be equipped with a functioning system that immediately and automatically cuts off the ECF feed when: (1) the limits for CO emissions or APCD inlet temperature are exceeded; (2) if the CO CEMS or the gas temperature detector malfunctions; and (3) when any component of the automatic ECF cutoff system malfunctions. Occurrences of automatic feed cutoffs must be investigated, corrective measures taken, and findings recorded in the operating record. Excessive exceedances must be reported to the Administrator as required under § 261.38(c)(2)(F).
6. **Boiler load**. Boiler load must not be less than 40 percent. Boiler load is the ratio at any time of the total heat input to the maximum design heat input;
7. **ECF must be fired into the primary fuel flame**. This requirement is to ensure that ECF does not completely bypass the flame. If this were to occur, potential exists for a combustion failure that would not be detected by an increase in CO emissions.
8. **Fuel atomization**. ECF must be fired directly into the primary fuel flame zone of the combustion chamber with an air or steam atomization firing system, mechanical atomization system, or a rotary cup atomization system under the following conditions:
    - (a) *Particle size*. ECF must pass through a 200 mesh (74 micron) screen;
    - (b) *Mechanical atomization systems*. Fuel pressure within a mechanical atomization system and fuel flow rate shall be maintained within the design range taking into account the viscosity and volatility of the fuel;

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[79] Note that oxygen must also be measured with a CEMS.

(c) *Rotary cup atomization systems*. Fuel flow rate through a rotary cup atomization system must be maintained within the design range taking into account the viscosity and volatility of the fuel.

9. **Restrictions on benzene and acrolein**. If the as-fired concentration of benzene or acrolein in the ECF exceeds 2%by mass, the ECF firing rate cannot exceed 25% of the total fuel input to the boiler on heat or volume input basis, whichever results in a lower volume input of ECF.

6.2.3 More on Atomization

Atomization, the process of breaking up a liquid stream into small droplets, ensures rapid evaporation and thereby fast and efficient combustion of the stream by increasing the surface area to volume ratio of the fluid.[80] As a condition of the exclusion, the ECF firing system must provide proper atomization to ensure that ECF droplets are sufficiently small. The acceptable atomization systems for ECF burners are those that are commonly used for firing liquid fuels.[81] These include:

1. Air or steam atomization (twin fluid atomization)
2. Mechanical or pressure atomization.
3. Rotary cup atomization

Each of these atomization systems are briefly discussed below.

Twin Fluid Atomization. In twin fluid atomization systems, either air or steam is used to break up the liquid fuel into a fine mist. When steam is used for atomization, it can also serve to heat the liquid fuel and thereby reduce its viscosity. In addition to subdividing by type of atomizing fluid used, these nozzles may also be categorized as high-pressure versus low pressure. In high pressure nozzles, steam or air (at pressures of 30-150 psig) impinges on the liquid stream at high velocity.[82] The atomizing fluid requirements are 20-200 ft^3 air or 2 to 5 lbs of steam per gallon of liquid fuel. These atomizers can handle fluids with viscosities as high as 150-5000 SSU (33 -1100 cS).[83]

In low pressure, air atomized systems, compressed air is provided at 1-5 psig. The quantify of atomizing air required is higher than that for high pressure nozzles, and is in the range 400 to 1000 ft^3 per gallon of fuel. The higher steam/air flowrates used in these nozzles cause shorter flames and thereby they require smaller combustion chambers when compared with the high pressure nozzles.

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[80] For a spherical droplets the surface area to volume ratio is equal to 6/d, where d is the diameter of the droplet. Therefore the smaller the droplet the higher the surface area per given volume of fuel that is available to absorb heat from the flame.

[81] Engineering Science, “Background Information Document for the Development of Regulations to Control the Burning of Hazardous Wastes in Boilers and Industrial Furnaces, Volume I: Industrial Boilers,” January 1987.

[82] Brunner,C.R., 1989 “Handbook of Hazardous Waste Incineration,” Tab Books Inc.,

[83] Note that ECF cannot have an as-fired viscosity exceeding 50 cs.

Two other kinds of twin fluid nozzles that are occasionally used are internal mix nozzles, where the atomizing medium is introduced within the nozzle and impinges on the liquid stream prior to discharge, and sonic nozzles, which use a compressed gas to create high-frequency sound waves that break up the liquid stream.

Mechanical Atomization. Mechanical atomizers do not require an atomizing fluid such as steam or air but rather direct the fuel through small discharge orifice to create small droplets. The liquid is pumped at a relatively high pressure and is given a strong "cyclonic" velocity (from internal tangential guide slots) before it is sent through the orifice. The nozzle typically provides a conical spray pattern and combustion air is provided on the periphery of the cone. The combination of combustion air and the action of the swirling fuel produces effective atomization. The turndown ratios are usually on the order of 3:1 but higher turndown ratios can be obtained by using a return flow for the liquid fuel. Liquids with moderate viscosities may be atomized to sufficiently small droplets with pressures in the range 75-150 psig but higher viscosity liquids will require higher pressures. Additionally, since low volatile fuels would need to be atomized to comparatively smaller droplets to ensure efficient combustion, these fuels would require a comparatively higher atomization pressure.

In general mechanical atomizers are used with fuels with viscosity below 100 SSU (~22 cS). In comparison to other types of atomizers, mechanical atomizers are more susceptible to erosion and plugging from solids in the liquid stream.

Rotary-Cup Atomization: In this configuration, the liquid stream is atomized by discharging it centrifugally from a rotating cup. The rotary cup is mounted on a hollow shaft and rotates at speeds up to several thousand revolutions per minute. Liquid is torn from the lip of the cup in the form of thin conical sheets. Air is introduced through an annular space around the rotating cup. Since rotation rate and combustion air flow are the main factors impacting atomization not much liquid pressurization is required. Rotary cup atomizers can handle fuels with relatively high viscosities up to 170 - 300 SSU (40 to 72 cS), and they are relatively insensitive to solid impurities in the fuel, and can handle waste fuels with solids with maximum particle size below 35-100 mesh.[84]

Figure 6-1 shows a schematic of commonly used atomization systems.

6.3 Other Conditions

ECF may not be managed by any entity other than the generator, transporter, and designated burner to facilitate compliance assurance. Also, additional conditions apply to ECF generators and burners (beyond what is required for generators and burners of comparable fuels) regarding notifications, reporting, and recordkeeping. These are listed in the proposed rule at §261.38(c)(4)

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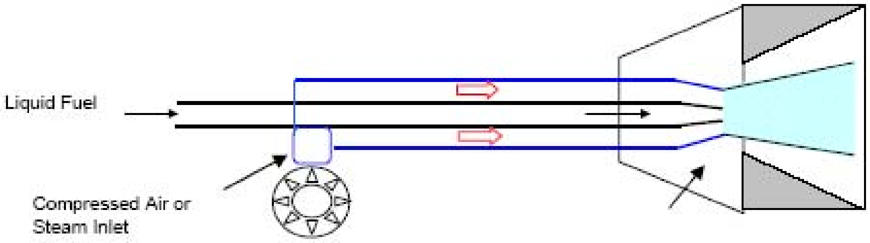
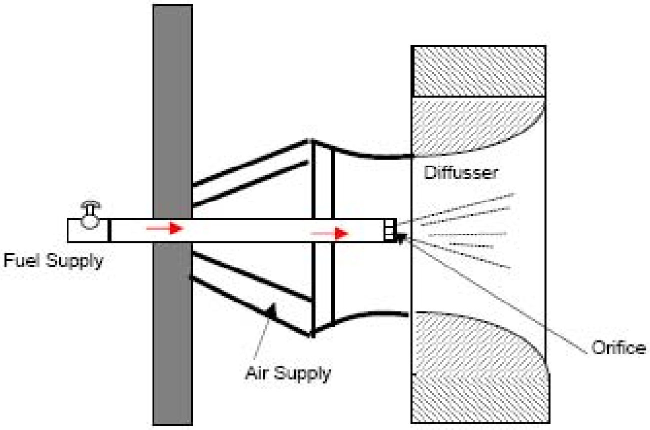
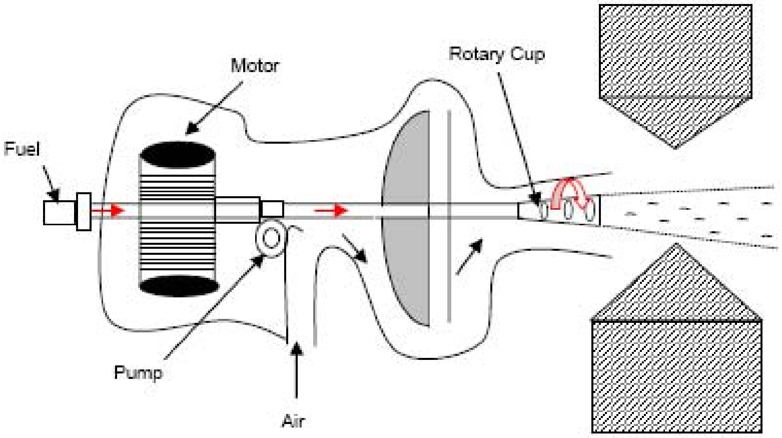
[84] Note that 35 and 100 mesh corresponds to a particle size less than 500 microns and 150 microns respectively. Note, however, that ECF must be able to pass through a 200 mesh (74 micron) sieve to ensure that particles are small enough to ensure volatilization and destruction of organic compounds.



(a) Twin-Fluid Atomizer



(b) Mechanical Atomizer



(C) Rotary Cup Atomizer

Figure 6-1: Commonly-Used Atomization Systems for Liquid Fuels (Adapted from Brunner (1989)

7 Engineering Costs and Savings

This section discusses waste quantities qualifying as ECF and savings and costs incurred by generators and burners of ECF under various regulatory options EPA considered for tracking and storage of ECF. Note that this analysis is limited to waste streams identified by respondents to a survey by the American Chemistry Council.[85] EPA also conducted an independent analysis to identify waste streams that may qualify as ECF, and estimated the costs and savings using that data base. See USEPA, "Assessment of the Potential Costs, Benefits, and Other Impacts of the Expansion of the RCRA Comparable Fuel Exclusion—Proposed Rule," May 2007.

7.1 Regulatory Options

Three primary regulatory options were considered for analysis. Under all options, generators and burners must provide a one time notification to the Regional Administrator. Offsite burners must also provide a one time certification to the generator that they will comply with the storage and burner conditions.

- <u>Option A</u> (Currently Applicable Product Controls): No specific controls for storage; any existing controls for commercial products would apply. Records must be kept of each shipment to an off-site burner. DOT shipping papers may be required for some shipments (i.e., for ECF that meets the DOT definition of a hazardous material (HAZMAT)).
- <u>Option B</u> (Tailored Management Conditions): Storage requirements per Spill Prevention and Control Countermeasure (SPCC) regulations in 40 CFR 112 that apply to fuel tank systems, other than secondary containment. These include tank integrity assessment and tank inspections, tests and recordkeeping. Generators and burners must also conduct personnel training and must follow certain preparedness and prevention, emergency procedures, and response to release provisions applicable to hazardous waste tanks. Additionally, ECF storage tanks would need "engineered" secondary containment: an external liner, vault, or use of double walled tank.[86] Further, certain storage tanks would need Level 2 air emissions controls based on requirements of the organics liquid distribution (OLD) NESHAP. Similar to Option A, records must be kept of each shipment to an off-site burner, and DOT shipping papers may be required for some shipments. Offsite burners must provide a one time certification to the generator that they will comply with the storage and burner conditions.

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[85] Letter from American Chemistry Council (Carter Lee Kelly, Leader, Waste Issues Team, and Robert A. Elam, Director, Regulatory Affairs, Waste Issues Team) to Robert Springer and Matt Hale, USEPA, dated November 24, 2003.

[86] This is similar to secondary containment required by the states of Florida and Minnesota for above ground fuel oil tanks.

- Option C (Subtitle C Storage/tracking) – ECF would be stored, tracked, and transported as hazardous waste subject to RCRA Subtitle C storage and tracking requirements. This requirement means that the point of exclusion would be moved to the ECF burner nozzle. Thus, 40 CFR 265, Subpart J tank standards would apply to storage of ECF by generators who accumulate ECF for less than 90 days, and the permit standards under Part 264 (including the Subpart J tank standards) would apply to generators who accumulate for more than 90 days and to burner storage units. The Part 265 and Part 264 Subpart J tank standards require engineered secondary containment virtually identical to Option B. Additionally, tank systems would be subject to the RCRA air emissions controls under Subparts BB and CC of Parts 265 or 264. The Part 264 standards would also require off-site burner storage units (and generators who accumulate ECF for more than 90 days) to comply with closure and financial assurance requirements and groundwater monitoring requirements and to obtain a RCRA storage permit. As discussed in Section 7.5.3 below, we analyzed savings for options C under two different scenarios.

7.2 Analysis of ACC Survey

As discussed in Section 1, the ACC survey provided detailed information on 95 hazardous waste streams that are currently not qualifying for the comparable fuels exclusion.[87] However, only 76 of these streams were subject to further analysis because:

- 17 streams did not contain sufficient information on heating values and/or annual quantities generated.
- Two wastestreams, N-01-13 and N-01-14 are currently not handled as a hazardous waste.

Many of these 76 streams were failing the current comparable fuel specification for only one or two of the compounds in Table 1 to § 261.38, Table. However, the survey did include many streams that failed the specifications for constituents other than oxygenates and hydrocarbons and would not qualify as ECF. Table 7-1 provides a summary of failing constituents for each of the 76 streams. Forty three of these streams are failing the specifications for metals or halogenated, nitrogenated, or sulfonated organics or Hazard Category A hydrocarbons.[88] See discussion of the Relative Hazard Categorization Scheme in Section 2.4 above. These wastestreams would not qualify as ECF.

As for wastestreams failing the specification for oxygenates or hydrocarbons, the table shows which specific constituents are failing the specifications. Fifteen streams fail the current specifications for toluene, ten fail for isobutyl alcohol, nine fail for methyl ethyl ketone (MEK), and six fail for benzene. Eight wastestreams are listed in the “none/unknown” category. These streams either did not fail for any constituent or they

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[87] Although the ACC survey table shows 96 streams, one stream L-02-12 was duplicated on a 2nd row.

[88] Six streams totaling 9.4 million lbs/yr are failing the specifications for naphthalene, a hazard category A hydrocarbon.

have not been evaluated in detail by generators to identify failing constituents. We assumed these streams would qualify as ECF.

Waste Stream ID	Loc Code	Gen Code	Failing for metals or other 261.38 constituent	Failing for oxygenates or hydrocarbons in Table 1 of 40 CFR 261.38																		ECF or HW
				CAT. A	CAT. B		CAT. C							Haz. Cat. A only		Haz. Cat. B		Haz. Cat. C		None/Unknown		
				Napthalene	Benzene	Acrolein	Toluene	Acetophenone	Cresol	Methyl Methacrylat	MEK	Isobutyl Alcohol	None/Unknown	lbs/yr	MM Btu/yr	lbs/yr	MM Btu/yr	lbs/yr	MM Btu/yr	lbs/yr	MM Btu/yr	
A-01-11	A-01	A	1																			HW
A-01-12	A-01	A	1																			HW
A-01-13	A-01	A	1																			HW
A-02-11	A-02	A	1																			HW
A-02-12	A-02	A	1																			HW
A-02-13	A-02	A	1																			HW
B-01-11	B-01	B									1	1						16,005,000	176,055			ECF
B-01-12	B-01	B			1		1	1								1,850,000	20,720					ECF
B-01-13	B-01	B			1											15,960,000	178,752					ECF
B-02-14	B-02	B									1	1						118,037,400	1,298,411			ECF
D-01-11	D-01	D	1	1	1									500,000	9,000							HW
D-01-12	D-01	D											1							2,300,000	41,400	ECF
D-02-11	D-02	D									1	1						2,974,760	29,748			ECF
D-03-11	D-03	D											1							500,000	10,000	ECF
D-03-14	D-03	D					1											1,200,000	23,400			ECF
D-04-12	D-04	D					1											6,000,000	117,000			ECF
D-04-13	D-04	D					1											1,000,000	19,500			ECF
D-05-11	D-05	D									1	1						56,176,000	674,112			ECF
D-05-12	D-05	D											1							374,000	6,620	ECF
D-05-13	D-05	D											1							613,282	6,623	ECF
D-05-14	D-05	D	1																			HW
D-06-11	D-06	D											1							1,000,000	11,000	ECF
D-06-12	D-06	D	1																			HW
D-07-13	D-07	D	1	1	1		1							734,000	8,808							HW
F-01-11	F-01	F	1																			HW
F-01-12	F-01	F	1																			HW
F-01-13	F-01	F								1								1,400,000	15,750			ECF
F-01-14	F-01	F	1																			HW
F-01-16	F-01	F										1						50,000	650			ECF
F-01-17	F-01	F	1																			HW
F-01-18	F-01	F	1																			HW
G-01-11	G-01	G				1										600,000	7,500					ECF
G-01-12	G-01	G				1										300,000	5,070					ECF
G-01-13	G-01	G				1										400,000	7,920					ECF
G-02-11	G-02	G	1	1			1				1	1		1,500,000	18,750							HW
G-02-12	G-02	G	1	1			1				1	1		2,500,000	31,250							HW
G-03-11	G-03	G	1																			HW
G-05-11	G-05	G	1																			HW
G-07-11	G-07	G	1																			HW
G-08-11	G-08	G	1																			HW
G-09-11	G-09	G	1																			HW
G-18-11	G-18	G	1																			HW
J-01-11	J-01	J	1																			HW
J-01-12	J-01	J	1																			HW
J-01-13	J-01	J	1																			HW
J-01-14	J-01	J	1																			HW
J-04-11	J-04	J	1																			HW
J-04-12	J-04	J	1																			HW
J-05-11	J-05	J					1					1						1,900,000	26,600			ECF
J-05-12	J-05	J	1	1							1	1		1,200,000	16,800							HW
K-01-11	K-01	K	1																			HW
K-01-12	K-01	K				1			1			1				5,000,000	45,000					ECF
K-01-13	K-01	K	1																			HW
K-01-14	K-01	K	1		1																	HW
K-04-12	K-04	K				1										4,700,000	37,600					ECF
L-01-11	L-01	L	1	1	1		1							3,000,000	55,500							HW
L-02-12	L-02	L	1																			HW
L-02-11	L-02	L					1											3,000,000	30,000			ECF
L-05-11	L-05	L	1																			HW
L-06-11	L-06	L									1							4,700,000	70,500			ECF
L-06-12	L-06	L											1							1,300,000	14,950	ECF
L-06-13	L-06	L	1																			HW
L-06-14	L-06	L											1							1,030,000	10,300	ECF
L-06-15	L-06	L	1																			HW
L-06-16	L-06	L	1																			HW
L-06-17	L-06	L	1																			HW
L-06-18	L-06	L									1							36,000	450			ECF
L-06-19	L-06	L	1																			HW
L-06-20	L-06	L	1																			HW
L-06-21	L-06	L											1							17,000	255	ECF
M-01-11	M-01	M	1																			HW
M-03-12	M-03	M					1											1,100,000	19,800			ECF
M-03-13	M-03	M					1											570,000	10,260			ECF
M-03-14	M-03	M					1											550,000	9,900			ECF
M-03-15	M-03	M					1											1,720,000	30,960			ECF
M-03-16	M-03	M					1											1,020,000	17,340			ECF
			43	6	6	5	15	1	1	1	9	10	8	9,434,000	140,108	28,810,000	302,562	217,439,160	2,570,436	7,134,282	101,148	

Table 7-1: Classification of Wastestreams from ACC Survey.

7.3 Estimate of Qualifying ECF Quantities

Based on information provided in the previous section, we estimated the quantity of hazardous waste that would qualify as emissions-comparable fuels by screening out streams that would not meet the definition of ECF.

- Forty three streams would not be eligible as ECF because they fail the specifications in Table 1 to §261.38 for compounds other than the hydrocarbons and oxygenates for which the specifications would not apply. These streams fail the specification for compounds such as metals, halogenated organics, or Relative Hazard Category A hydrocarbons. These streams amount to 121.1 million lbs per year (or 60,600 tons/yr) with a weighted average heating value of 10,500 Btu/lb. These will continue to be managed as hazardous waste. See Table 7-2. Note that only 6 waste streams totaling 4,700 tons/yr would be ineligible as ECF solely because they fail the specification for a Hazard Category A hydrocarbon (i.e., naphthalene).

Thirty three streams meet the definition of ECF. These 33 ECF streams amount to 253.4 million lbs/yr (or 126,700 tons/yr), and are generated at 16 sites representing eight different companies.[89] These streams have a combined thermal value of 2.97×10^6 MM Btu/yr or a weighted average heating value of 11,700 Btu/lb. Table 7-2 shows a stream-by-stream breakdown of these results. The amount of qualifying ECF is dominated by two streams (one at 118 million lb/year and the other at 56 million lb/yr) together accounting for more than 60% of the qualifying waste.

7.4 Preliminary Information Used in Costs/Savings Estimate

7.4.1 Value of Fuel Oil and ECF

The Department of Energy's Energy Information Administration gathers information on fuel oil pricing. March 2006 prices for #2 fuel oil and residual fuel oil were $1.79/gallon and $1.19/gallon, respectively, which was a 33% increase (on average) from March 2005 levels.[90] The March 2005 price for fuel oil #4 was listed as $1.16/gallon (this is the latest information available for fuel oil # 4). Based on the average increase for other types of fuel oil we can estimate the March 2006 price for fuel oil #4 at $1.54/gallon. This cost is equivalent to $426/ton or $11/ MM Btu assuming a heating value of 139,400 Btu/gal.

We assumed that the value of ECF as a fuel would be similar to that of fuel oil # 4 on a thermal input basis. However, given that ECF is a conditionally-excluded hazardous waste subject to substantive storage and burner conditions (and liability if those conditions are not met), and may contain an increased level of some hazardous constituents when compared with fuel oil, we estimate that the value of ECF would be 75% of that of fuel oil and would be equivalent to $11* 75% or $8.25 $/MM Btu.

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[89] The waste stream IDs in the ACC survey had the form x-XX-XX (for e.g. A-01-12). We assumed that the letter in the code represented a single company and the first 2 digit number represented a unique generating site. This approach may have underestimated the number of generating sites.

[90] http://tonto.eia.doe.gov/dnav/pet/hist/a803700002m.htm

Waste Stream ID	Loc Code	Gen Code	**ECF or HW**	Hazardous Waste		ECF	
				lbs/yr	MM Btu/yr	lbs/yr	MM Btu/yr
A-01-11	A-01	A	HW	1,500,000	23,250		
A-01-12	A-01	A	HW	2,000,000	18,200		
A-01-13	A-01	A	HW	1,000,000	11,200		
A-02-11	A-02	A	HW	1,200,000	21,600		
A-02-12	A-02	A	HW	2,600,000	46,800		
A-02-13	A-02	A	HW	1,900,000	34,200		
B-01-11	B-01	B	ECF			16,005,000	176,055
B-01-12	B-01	B	ECF			1,850,000	20,720
B-01-13	B-01	B	ECF			15,960,000	178,752
B-02-14	B-02	B	ECF			118,037,400	1,298,411
D-01-11	D-01	D	HW	500,000	9,000	0	0
D-01-12	D-01	D	ECF			2,300,000	41,400
D-02-11	D-02	D	ECF			2,974,760	29,748
D-03-11	D-03	D	ECF			500,000	10,000
D-03-14	D-03	D	ECF			1,200,000	23,400
D-04-12	D-04	D	ECF			6,000,000	117,000
D-04-13	D-04	D	ECF			1,000,000	19,500
D-05-11	D-05	D	ECF			56,176,000	674,112
D-05-12	D-05	D	ECF			374,000	6,620
D-05-13	D-05	D	ECF			613,282	6,623
D-05-14	D-05	D	HW	464,943	3,487		
D-06-11	D-06	D	ECF			1,000,000	11,000
D-06-12	D-06	D	HW	1,000,000	14,500		
D-07-13	D-07	D	HW	734,000	8,808	0	0
F-01-11	F-01	F	HW	7,000,000	40,600		
F-01-12	F-01	F	HW	120,000	1,186		
F-01-13	F-01	F	ECF			1,400,000	15,750
F-01-14	F-01	F	HW	500,000	6,500		
F-01-16	F-01	F	ECF			50,000	650
F-01-17	F-01	F	HW	1,700,000	11,050		
F-01-18	F-01	F	HW	1,500,000	27,000		
G-01-11	G-01	G	ECF			600,000	7,500
G-01-12	G-01	G	ECF			300,000	5,070
G-01-13	G-01	G	ECF			400,000	7,920
G-02-11	G-02	G	HW	1,500,000	18,750	0	0
G-02-12	G-02	G	HW	2,500,000	31,250	0	0
G-03-11	G-03	G	HW	750,000	10,725		
G-05-11	G-05	G	HW	1,000,000	18,000		
G-07-11	G-07	G	HW	1,400,000	13,160		
G-08-11	G-08	G	HW	10,000,000	110,000		
G-09-11	G-09	G	HW	1,500,000	27,000		
G-18-11	G-18	G	HW	31,000,000	285,200		
J-01-11	J-01	J	HW	190,000	2,323		
J-01-12	J-01	J	HW	1,092,000	16,380		
J-01-13	J-01	J	HW	38,000	456		
J-01-14	J-01	J	HW	540,000	5,076		
J-04-11	J-04	J	HW	6,000,000	102,000		
J-04-12	J-04	J	HW	700,000	5,950		
J-05-11	J-05	J	ECF			1,900,000	26,600
J-05-12	J-05	J	HW	1,200,000	16,800	0	0
K-01-11	K-01	K	HW	5,000,000	28,750		
K-01-12	K-01	K	ECF			5,000,000	45,000
K-01-13	K-01	K	HW	3,000,000	27,000		
K-01-14	K-01	K	HW	17,000,000	119,000		
K-04-12	K-04	K	ECF			4,700,000	37,600
L-01-11	L-01	L	HW	3,000,000	55,500	0	0
L-02-12	L-02	L	HW	21,000	361		
L-02-11	L-02	L	ECF			3,000,000	30,000
L-05-11	L-05	L	HW	200,000	3,120		
L-06-11	L-06	L	ECF			4,700,000	70,500
L-06-12	L-06	L	ECF			1,300,000	14,950
L-06-13	L-06	L	HW	1,000,000	16,000		
L-06-14	L-06	L	ECF			1,030,000	10,300
L-06-15	L-06	L	HW	715,000	12,870		
L-06-16	L-06	L	HW	85,000	1,530		
L-06-17	L-06	L	HW	83,000	1,494		
L-06-18	L-06	L	ECF			36,000	450
L-06-19	L-06	L	HW	350,000	4,725		
L-06-20	L-06	L	HW	40,000	480		
L-06-21	L-06	L	ECF			17,000	255
M-01-11	M-01	M	HW	7,500,000	60,000		
M-03-12	M-03	M	ECF			1,100,000	19,800
M-03-13	M-03	M	ECF			570,000	10,260
M-03-14	M-03	M	ECF			550,000	9,900
M-03-15	M-03	M	ECF			1,720,000	30,960
M-03-16	M-03	M	ECF			1,020,000	17,340
				121,122,943	**1,271,281**	**253,383,442**	**2,974,146**

Table 7-2: ACC Survey based ECF Waste Quantities.

7.4.2 Hazardous Waste Disposal Costs

Disposal costs, currently being incurred by some generators, for ECF streams being disposed of as hazardous waste, is estimated to be $0.96/gal.[91] This is the 2004 average tipping fee for bulk, liquid, nonhalogenated waste charged by commercial incinerators. Assuming ECF has a density equivalent to that of water, we can estimate the disposal costs to be $231/ton. This disposal cost is not inconsistent with the limited information available in the ACC survey which shows disposal cost information for five streams. The weighted average disposal cost is $231/ton, although a range from $130/ton to $270/ton was reported.

7.4.3 Labor Costs

Labor costs are taken from the BIF rule ICR.[92] The rates are adjusted to March 2006 levels by increasing the ICR rates based on the increase in consumer price index.[93] As Table 7-3 shows, the rates vary from about $34/hour for clerical support to $119/hour for legal/consultant support.

		ICR 1361.10	Adjusted for 2006
Legal	$/hr	117.00	119.18
Manager	$/hr	89.01	90.67
Technical	$/hr	68.48	69.75
Clerical	$/hr	32.97	33.58

Table 7-3 Burdened Labor Rates for Economic Analyis

7.4.4 Estimation of the Number of ECF Shipments

For generators who would ship their ECF off-site for burning, we are assuming that shipments occur when the volume of each stream reaches 9000 gallons.[94] However, we are also assuming that each stream is shipped at least once every 90 days to satisfy accumulation time requirements for 90-day HW generator tanks under §262.34.

So for a given generator site,

$$\text{Shipments per year of a given ECF stream} = \textit{greater of} \begin{cases} \text{ECF Stream Volume (gallons/yr)/9000 (gallons)} \\ 4 \end{cases}$$

Appendix E shows the estimated number of shipments by generator site for each qualifying waste stream.

7.4.5 Estimation of Tank Size for Generators and Burners

In order to estimate storage costs, it was necessary to estimate the tank size for burners and generators.

<u>Generators:</u> For generators, we assume that each ECF stream will be stored in a separate tank. Therefore:

Number of ECF tanks = Number of ECF streams

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[91] http://www.etc.org/costsurvey8.cfm

[92] USEPA, "Supporting Statement for EPA ICR 1361.10," October 2005.

[93] ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.tx - link no longer viable

[94] This is based the size of a typical tanker truck.

There is a large range of production rates among individual ECF streams. For example, the 90-day production rate varies from 500 gallons to 3.5 million gallons. Although facilities producing very large quantities can ship and or transfer their waste to the burner frequently (even multiple times a day) the generator must have storage capacity to account for burner downtime and other contingencies (such as shipment delays).

If combusting at onsite burner: We assume the size of the generator tank should be at least sufficient to store 2 weeks of ECF. So:

Tank Size[95] = Biweekly ECF stream generation rate (gallons per 2 weeks) * 2

If combusting at offsite burner: The 2 week storage minimum applies but also consider that generators must ship at least once every 90 days.

- If generation rate is greater than 9000 gallons/ 2 weeks,

  Tank Size (gallons) = 2 Biweekly generation rate (gallons)*

- If generation rate is less than 9000 gallons every 3 months:

  Tanks Size (gallons) = 2 90 day generation rate (gallon)*

- For intermediate generation rates:

  *Tank Size (gallons) = 2*9000*

  Tank size is rounded up to the nearest 1000 gallons. Sizes vary from 2000 to 1.1 million gallons.

Burners: We estimate that all the ECF streams from a single generating site will go to a single boiler. And, we assume that this burner will store all the ECF streams together in a single tank. Assuming that the burner tank needs to be large enough to hold a couple of days of the aggregate ECF:

Burner Tank Size (gallons) = 2 2* Total ECF sent to burner in a day (gallons)*

Based on these estimates burner tank size varies from 2000 to 160,000 gallons

The results of these analyses are shown in Appendix E.

7.4.6 Generator Types and ECF burn Scenarios

Based on the ACC survey, we ascertained that 16 sites representing eight companies had qualifying ECF. These sites could be categorized into two groups.

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[95] An additional factor of 2 to provide sufficient headspace.

Group 1: There are nine sites with qualifying ECF currently incurring disposal costs, i.e., these sites are currently paying a fee (to incinerators, cement kilns or fuel blenders) to dispose of ECF as hazardous waste. These sites are D-01, D-02, D-03, D-04, F-01, J-05, L-02, L-06, and M-03. Group 1 sites taking the ECF exclusion will save on hazardous waste disposal costs. Additionally, since ECF will displace fossil fuels burners will have fuel savings. These generators and burners will incur costs for recordkeeping and storing ECF, analyzing ECF for toxic constituents, and for installing burner controls. These costs, as discussed in the next subsection, will vary by the regulatory option being considered.

Group 2: There are seven sites with qualifying ECF that we determined are not currently incurring disposal costs. These sites will not realize any savings for displaced fuel or hazardous waste disposal but they will have other cost savings such as storage. Based on the information provided, we assumed three different scenarios for these sites.

1. Scenario 1: ECF is burned onsite in a boiler that remains a hazardous waste boiler. (K-01, K-04)
2. Scenario 2: ECF is burned onsite in a boiler that exits the HW/MACT regulatory system. (B-01)
3. Scenario 3: ECF is burned offsite at an affiliated boiler (i.e., a boiler owned by the parent company) that remains a HW boiler. (B-02, D-05, D-06, G-01)

7.5 Costs/Savings Estimation

The costs and net savings to ECF generators/burners depend on the regulatory option as well as the classification discussed in Section 7.4. Primary assumptions used are:

1. All qualifying ECF generated at a single site will be burned at a single steam watertube boiler that would be modified to meet ECF combustion control requirements. We assume that for each generating site such a boiler is located close enough to the generator site that makes transportation of ECF to the boiler economically feasible.
2. The boiler may be located onsite or offsite. Based on the ACC survey it was determined that the following facilities will send their ECF off site for combustion: B02, D05, D06, G01, D01, D04, F01, J05, L06, and D02.

Group 1 and Group 2 sites are handled differently for purposes of estimating savings. The itemized cost estimates were derived from information collection request (ICR) supporting statements for several different rules, review of information available from EPA, DOE and other agencies, and vendor quotes. Reasonable assumptions were made in cases where the information was not readily available. Appendix F lists unit cost/savings for each item below as well as assumptions and information sources used. Appendix G contains the cost model that was developed based on these assumptions.

Details of the cost and savings analysis are provided below.

7.5.1 Group 1 Sites:

Savings:

1. Fossil fuel savings assuming ECF is valued at $8.25/MMBtu.
2. Savings for not managing ECF as hazardous waste - $ 272/ton (includes $231/ton for disposal, $14/ton for manifesting, and $27/ton for generator storage.[96])

Costs

Costs vary by regulatory option and include costs to comply with the regulatory requirements as well as costs deemed to arise from standard operating procedures (SOP).[97] The cost model groups the costs into five primary components: (1) boiler costs associated with retrofitting a typical fuel oil boiler to meet the requirements of an ECF boiler; (2) analytical costs incurred to test candidate ECF streams for the specification constituents and properties; (3) tracking costs for shipping papers/manifests and maintaining records; (4) generator storage costs to replace, inspect, and maintain storage tanks, provide secondary containment and air emissions controls; and (5) burner storage costs. These components are discussed in detail below.

Boiler-

Costs apply equally to all regulatory options.

- Carbon Monoxide Monitor[98] – Assume one time installed cost of $5800 per boiler annualized over 10 years.
- Automatic Feed Cutoff - Assume one time installed cost of $3800 per boiler annualized over 10 years.
- Firing Nozzle – Assume 50% of boilers would require a new firing nozzle. One time cost (annualized over ten years) of $350 for an ECF feedrate of 3.3 gallons per minute. Costs scale with ECF feedrate.[99]
- Costs for maintenance, calibration, and recordkeeping related to CO CEMS and ECF feed systems and automatic feed cutoff – 1.75 hours per day or $30,400 annually per boiler.

Analytical

Analytical costs apply equally to all options

- Testing – Assume $8100 per test per ECF stream for analyzing all 261.38 constituents (including volatile and semi-volatile organics, metals, PCBs, total nitrogen etc.) and for evaluating other properties such as sulfur and ash content, heating value, and viscosity. The cost takes into account that iterative

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[96] The savings for HW manifests and generator storage are equal to the costs for these items under regulatory option C.

[97] Absent a condition of the exclusion, we nonetheless assumed that facilities would incur certain costs to implement standard operating procedures (SOP), such as keeping records of each shipment of waste fuel under Regulatory Option A.

[98] Assumes every boiler burning ECF will purchase a new CO CEMS and every boiler is already equipped with an oxygen CEMS.

[99] A 0.6 scaling factor was used in all economic estimates where the size of the item had an impact on the cost.

analysis may be required to achieve low detection limits. Assume 50% waste streams are tested annually, while the rest are tested semi-annually.

- Recordkeeping – Assume $1200 per test for maintaining lab documentation of testing (test methods, quantization limits, QA/QC records etc) and for certifying certain compounds are not in ECF based on process knowledge.

Tracking –

Tracking costs vary by regulatory option and include:

- Shipping papers - Every shipment under Option C will require hazardous waste manifests at a cost of $50 per manifest. Assume all shipments under Options A and B will be accompanied by DOT shipping paper (at half the cost of a hazardous waste manifest).[100]
- One-time notification to the Regional Administrator by the generator and off-site burner at $160 per notification annualized over 20 years. (all options)
- Transporters and offsite burners obtain EPA ID number at a one time cost of $470 annualized over 20 years (Options B and C).
- One-time certification by an off-site burner to the generator that burner is in compliance with storage and burner controls at a one time cost of $264 annualized over 20 years. (all options)
- Recordkeeping for each shipment at $30 per shipment. (all options).

Generator Storage

A key assumption for the cost estimate for both generator and burner storage is that ECF will be stored in above ground tanks only. Generator storage costs also vary by regulatory option and include:

- Replacement of storage tanks at an installed cost of $69,000 for a 20,000 gallon tank.[101] Cost for other tanks sizes are calculated using a 0.6 scaling factor.[102] The costs are annualized over 15 years. (all regulatory options)
- Secondary containment for storage tanks. Earthen berm for Option A (as standard operating procedures) at $1300 for a 1000 gal tank. Engineered secondary containment with leak detection for Options B/C at cost of $30,700 for 20,000 gallon tank. Cost for other tanks sizes are calculated using a 0.6 scaling factor and the costs are annualized over 15 years.
- Piping to from generator tanks to burn tank (assume 500 ft) - Applies for all options but only for onsite combustion at a cost of $4100 per tank annualized over 10 years.
- Daily visual inspection of tanks at a cost of $8 per inspection per tank (all options)[103]

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[100] This overestimates costs because ECF will require DOT shipping papers only if ECF meets the DOT definition of a hazardous material.

[101] Assume separate tank for each qualifying ECF stream. Tanks replacement schedule: 33% replaced immediately, 33% after 5 years and 33% after 10 years.

[102] For example the installed cost for a 10,000 gallon tank would be = $69,000* $(10{,}000/20{,}000)^{0.6}$= $45,000.

[103] The visual inspections of tanks/equipment as well as monthly monitoring are based on requirements for hazardous waste tanks in Subparts J and CC of 40 CFR 265 and requirements for fuel oil tanks under SPCC

- Weekly visual inspection of pumps, valves and piping at a cost of $17 per inspection per tank (all options)
- Monthly monitoring for VOC leaks at cost of $150 per test per tank (all options)
- Certification of a major repairs by a professional engineer(PE)– Assume $490 per repair and assume each tank has one major repair every 5 years. (all options)-
- Cessation/containment of leaks- Leaks must be cleaned up as hazardous waste Assume three leaks per generator site per year as HW and labor and disposal costs total $1570 per leak.(all options)
- Notification and reporting of leaks to Regional Administrator (RA) at $1030 per leak (Options B and C)[104]
- SPCC Plan – For review of SPCC plan and certification by PE (Option B).[105] Plans are reviewed every five years. Equivalent costs are $257 per year per generator site.
- Facility Security - $300/yr (all options)
- Emergency Response - $280 per occurrence. Assume one occurrence per facility every five years. (all options)
- Equipment Testing/Maintenance- $210 per year for testing and maintenance of fire protection and spill control equipment. (all options)
- Air emissions controls - Cost of Level 2 air emissions control are estimated to be $20,100 per 20,000 gallon tank annualized over 15 years. Assume a fraction of tanks will install Level 2 controls for air emissions for their replacement storage tanks under the various options.
    - ➢ 50% under Option A (currently existing air emissions controls requirements),
    - ➢ 75% under Option B (requirements are per organics liquids distribution (OLD) NESHAP, in 40 CFR 63 Subpart EEEE), and
    - ➢ 75% under Option C (40 CFR 265 Subpart CC)[106]
- Recordkeeping related to air emissions-$1400 per tank per year for maintaining inspection records, tagging defective equipment etc. (options B/C).
- Operator Training – Assume 40 man hours of training annually at a total cost of $3600 per generator site (all options)

<u>Burner Storage</u> –

The following burner storage costs are identical to those of generators:

- Cost of new storage tank for each burner.[107] (all options)

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requirements. It is assumed that these inspections are SOP and would be performed under Option A as well.

[104] Assume spills are less than 42 gallons which is below the SPCC reporting threshold per 40 CFR §112.4

[105] Costs are for renewing existing plans.

[106] Assume that application of the CAA OLD NESHAP and RCRA Part 265/264, Subpart CC, will result in a similar number of tanks being subject to air emissions controls under Options B and C. However, assume that only 50% of tanks will be subject to Level 2 controls under existing product controls (Option A).

[107] All ECF streams combined in single new storage tank for each burner. Tank life is 15 years.

- Secondary containment (earth berm for Option A, engineered materials for Options B/C).
- Daily visual inspection of tanks. (all options)
- Weekly visual inspection of pumps, valves and piping. (all options)
- Monthly monitoring for VOC leaks. (all options).
- PE certification of major repairs. (all options)
- Cessation/containment of leaks as HW. (all options)
- Notification and reporting of leaks to RA. (Options B and C)
- SPCC Plan – Review SPCC plan and certify by PE (Option B)
- Security and Emergency Response for offsite burners (all options)
- Testing and maintenance of equipment. (offsite burners- all options)
- Air emissions controls- Assume 50% will install Level 2 air emissions controls under Option A, and 75% will install controls under Option B/C on replacement storage tanks.
- Recordkeeping related to air emissions (options B/C)
- Operator training- (offsite burners- all options)

The following costs will differ from those for generator storage tanks:

- Piping from burn tank to burner- $410 per burner annualized over 10 years. (all options)
- Closure /financial assurance (Option C) – Assume facilities will estimate cost of closure and make annual payments to a closure trust fund. Assume total estimated closure cost for site with 1 million gallon ECF capacity is $1.48 million.[108] Smaller capacity sites' costs are estimated using a 0.6 scaling factor. Costs include those for flushing the tanks, decontamination, demolition, and removal of containment systems, decontamination and removal of soil. Annual payment to a closure trust fund is estimated by annualizing total closure costs over 20 years. Also, assume $1800 per year for annual amendments to closure plan.
- Groundwater monitoring (offsite burners, Option C) – Assume detection monitoring only,i.e., compliance monitoring and corrective action not required. Assume capital costs for groundwater monitoring system of $143,000 (annualized over 15 years) and $40,300 per year for labor and O&M costs.[109]
- Permitting - (offsite burner, Option C) - Requirements for part B permit application including waste analysis plan, closure/financial assurance plan, certification of tanks and equipment. One time cost $171,800 for labor and O&M annualized over 10 years.[110] Assume permit renewal costs in 10 years are 50% of that of the original permit. This is equivalent to $18,300 per year for each offsite burner.

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[108] This estimate is based on a closure cost tool developed by Washington State Dept of Ecology, Hazardous Waste and Toxics Reduction Program,Publication # 05-04-009; May 2005

[109] These costs are based on, "Supporting Statement for EPA ICR 959.12, Facility Groundwater Monitoring Requirements," January 2005.

[110] From "Supporting Statement for EPA ICR # 1573.10, Part B Permit Application, Permit Modification, Special Permits, " February 2003

7.5.2 Group 2 Sites:

Costs/Savings depend on scenario and regulatory option.

- *Scenario 1*- ECF is burned onsite in a boiler that remains a hazardous waste boiler.

  Savings-
  1. Secondary containment on replacement storage and burn tanks. (Option A)
  2. Partial air emissions control costs. (Option A)
  3. Permit renewal costs for burn tanks. (Option A, B)

  Costs-

  SPCC Plan renewal and certification.(Opt B)

- *Scenario 2* – ECF is burned on site in a boiler that that would cease being a part of the RCRA/MACT regulatory system

  Savings-
  1. BIF/MACT compliance related – Assume $65,300 per year savings due to elimination of BIF/MACT compliance costs[111]. (All regulatory options)
  2. Secondary containment on replacement storage and burn tanks. (Option A)[112]
  3. Partial air emissions control costs. (Option A)
  4. Permit renewal costs. (Option A, B)

  Costs-

  SPCC Plan renewal and certification.(Opt B)

- *Scenario 3*- ECF is burned offsite in an affiliated boiler that remains a hazardous waste boiler.

  Savings-
  1. Tracking - Difference between costs of manifests and shipping papers. (Option A-B).
  2. Secondary containment on replacement storage and burn tanks. (Opt A)
  3. Partial air emissions control costs. (Option A)
  4. Permit renewal costs for burn tanks. (Opt A-B)

  Costs

  SPCC Plan renewal and certification. (Opt B)

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[111] Annualized savings based on elimination of one time SSRA costs of $300,000, one time PCDD/F test cost of $7700, Comprehensive performance test costs ($144,000 every 5 years), SSMP, notification of compliance, documentation of compliance etc.

[112] Difference between engineered secondary containment and cost of earth berm.

7.5.3 Additional Assumptions for Option C for Offsite Combustion of ECF

Given that Regulatory Option C would require offsite boiler to obtain a storage permit for ECF, we calculated savings estimates under two scenarios:

- Low End Savings Estimate – Assume no offsite shipment of ECF. Facilities that would otherwise ship their ECF to offsite facilities will not claim the exclusion.
- High End Savings Estimate – Assume limited offsite shipments of ECF. Some generators will claim the exclusion even if they do not have quantifiable savings for the intangible benefits associated with dealing with less hazardous waste.[113] Estimate also assumes commercial HWCs (incinerators and kilns) will reduce their fees rather than lose revenue from these streams.
    1. The following sites' ECF streams are currently burned in an affiliated boiler and would continue to do so: B02, D05, D06, and G01 – These sites claim the exclusion but incur no quantifiable savings.
    2. The following sites' streams are currently burned in an offsite commercial HWC and generators would claim the exclusion and continue to send ECF to the HWC under reduced fees: D01, D04, F01, J05, and L06 – These sites will incur savings of disposal costs. [114]
    3. The following site will not claim the exclusion: D02

7.6 Results and Discussion

The results of savings estimates are shown in Table 7-4. The results are shown for all three regulatory options and are also broken down for Group 1 and Group 2 sites. For each option, the number of companies, sites, and ECF streams that are estimated to take the exclusion are shown.

The quantity of waste that is excluded would be 126,700 tons/year under Regulatory Options A and B.[115] Under Option C the excluded waste quantity will vary between 25,600 to 125,200 tons/yr.[116] The table also shows fuel and hazardous waste management savings for Group 1 sites and other costs or savings (note-table shows costs in parenthesis) for both Group 1 and 2 sites. A site-by-site breakdown of these figures can be found in Appendix H.

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[113] For example, reduced taxes for managing hazardous waste.

[114] We assume commercial incinerators/kilns will reduce their disposal fees by 75%.

[115] The qualifying waste quantity is the same for all options and is equal to the excluded waste quantity under options A and B.

[116] See 7.5.3 for assumptions used to obtain high and low end estimates for option C.

TABLE 7-4: SUMMARY OF ACC(1) WASTE QUANTITIES AND SAVINGS FOR CFE REGULATORY OPTIONS

	Emissions-Comparable Fuel (ECF)																
Reg Option	Sub-Set[2]	No. of Companies	No. of Sites	No. of streams	Excluded Qty[7]		Thermal Value	Fuel Savings	Other Savings or Costs (Costs shown in parentheses)						Savings on HW Management	Total ECF Savings[3]	% Savings relative to Option A
					lb/yr	tons/yr	MMBtu/yr	$/yr	Boiler	Analytical	Tracking	Generator Storage/Air Emissions	Burner Storage/Air Emissions	BIF/MACT Compliance	$/yr	$/yr	
A: Currently Applicable Product Storage Controls	Group 1	5	9	20	32,367,760	16,184	498,763	$4,114,791	($289,545)	($278,581)	($19,865)	($346,246)	($158,272)	$0	$4,402,015	$7,424,296	
	Group 2	4	7	13	221,015,682	110,508	2,475,384	$0	$0	$0	$60,841	$105,495	$74,207	$65,290	$0	$305,833	
	Total	8	16	33	253,383,442	126,692	2,974,146	$4,114,791	($289,545)	($278,581)	$40,975	($240,751)	($84,066)	$65,290	$4,402,015	**$7,730,129**	**100%**
B: Tailored Management Conditions[4]	Group 1	5	9	20	32,367,760	16,184	498,763	$4,114,791	($289,545)	($278,581)	($19,716)	($444,083)	($212,915)	$0	$4,402,015	$7,271,967	
	Group 2	4	7	13	221,015,682	110,508	2,475,384	$0	$0	$0	$60,841	($1,799)	$14,050	$65,290	$0	$138,382	
	Total	8	16	33	253,383,442	126,692	2,974,146	$4,114,791	($289,545)	($278,581)	$41,125	($445,881)	($198,864)	$65,290	$4,402,015	**$7,410,349**	**96%**
C (Low): Subtitle C Storage, Low End Estimate[5]	Group 1	3	3	8	9,660,000	4,830	151,660	$1,251,195	($96,511)	($111,432)	($45)	($160,840)	($82,803)	$0	$1,313,760	$2,113,324	
	Group 2	2	3	5	43,515,000	21,758	458,127	$0	$0	$0	$0	$0	$0	$65,290	$0	$65,290	
	Total	5	6	13	53,175,000	26,588	609,787	$1,251,195	($96,511)	($111,432)	($45)	($160,840)	($82,803)	$65,290	$1,313,760	**$2,178,614**	**28%**
C (High): Subtitle C Storage, High End Estimate[6]	Group 1	5	8	19	29,393,000	14,697	469,015	$1,251,195	($96,511)	($111,432)	($45)	($160,840)	($82,803)	$0	$3,015,731	$3,815,295	
	Group 2	3	7	13	221,015,682	110,508	2,475,384	$0	$0	$0	$0	$0	$0	$65,290	$0	$65,290	
	Total	8	15	32	250,408,682	125,204	2,944,399	$1,251,195	($96,511)	($111,432)	($45)	($160,840)	($82,803)	$65,290	$3,015,731	**$3,880,585**	**50%**

Notes

(1) Estimates are based on qualifying Emissions-Comparable Fuel (ECF) streams from a survey of ACC members.

(2)Group 1 Sites: Currently incur disposal costs for qualifying ECF. These sites would have future savings for fuel as well as HW disposal savings.

Group 2 Sites: Currently do not incur disposal costs for qualifying ECF.

(3)These are net savings to both generators and burners.

(4)SPCC plus additional controls to minimize releases: engineered secondary containment/leak detection; air emissions controls.

(5)C (Low) assumes no off-site shipments b/c: (1) no quantifiable savings for affiliated burning; and (2) no off-site boilers will want to obtain storage permit (w/ corrective action).

(6)C (High) assumes limited off-site shipments b/c: (1) some unquantifiable savings/benefits for affiliated buring (e.g., lower impact taxes; reduced consequences of noncompliance w/ MACT); and (2) commercial HWCs may reduce fees by 75% to retain cheap source of fuel. If we assume that commercial HWCs will reduce their fees by only 20% vs 75%, generator savings would be $2.6 3 million rather than $3.89 million.

(7)Qualifying ECF under any of the regulatory options is 126,692 tons/year. Excluded quantities vary by option.

Net savings to generators and burners are also shown in the table. Under Option A, net annual savings are $7.73 million with Group 1 sites seeing 96% of these savings. Under Option B, more stringent requirements particularly for storage of ECF will result in slightly lower net savings of $7.41million per year or 96% of Option A savings. Annual savings under Option C range from $2.18 to $3.88 million (or 28-50% of Option A savings).

Limitations of the Analysis

As noted earlier, the analysis presented here is limited to information provided in the ACC survey. The survey contained information on generators that produce 187,000 tons/year of hazardous waste.[117] However, according to EPA's Biennial Reporting System, over 30 million tons of hazardous waste was generated in 2003.[118] A national estimate based on the 2003 Biennial Report and the 1996 hazardous waste constituent survey is presented elsewhere.[119]

Additionally, the analysis in this section does not account for transportation costs/savings. Note that generators who currently burn ECF onsite and would ship ECF offsite under the exclusion will incur transportation costs while others that are currently burning or disposing of the waste offsite may see some savings on transportation expenses

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[117] Note that respondents to the survey reported waste that they believed were candidate waste fuels that could potentially be excluded from RCRA regulation. The wastes were liquid hazardous wastes with a heating value > 5000 Btu/lb and which failed the comparable fuel specification for only a few constituents or for viscosity.

[118] USEPA, "The National Biennial RCRA Hazardous Waste Report (Based on 2003 Data).

[119] USEPA, "Assessment of the Potential Costs, Benefits, and Other Impacts of the Expansion of the RCRA Comparable Fuel Exclusion—Proposed Rule," May 2007.

List of Acronyms

ACC	American Chemistry Council
APCD	Air pollution control device
APCS	Air pollution control system
API	Air Petroleum Institute
ASTM	American Society for Testing and Materials
ATSDR	Agency for Toxic Substances and Disease Registry
BAF	Bioaccumulation factors
BCF	Bio-concentration factors
BIF	Boiler and industrial furnaces
CAA	Clean Air Act
CAS	Chemical abstract service
CFE	Comparable fuels exclusion
CO	Carbon monoxide
CO_2	Carbon dioxide
CEMS	Continuous emissions monitoring system
DOE	Department of Energy
DOT	Department of Transportation
DRE	Destruction and removal efficiency
ECF	Emission-comparable fuel
EER	Energy and Environmental Research
EPA	Environmental Protection Agency
EPCRA	Emergency Planning and Community Right-to-Know Act
ESP	Electrostatic precipitator
FF	Fabric filter
FID	Flame ionization detector
GC/MS	Gas chromatography/mass spectroscopy
HAP	Hazardous air pollutants
HAZMAT	Hazardous materials
HCl	Hydrogen chloride
HHV	Higher heating value
HWC	Hazardous waste combustor
ICI	Industrial, commercial and institutional
ICR	Information collection request
IR	Infrared
IRIS	Integrated risk information system
MACT	Maximum achievable control technology
MEK	Methyl ethyl ketone
MOE	Margin of exposure
MTBE	Methyl Tertiary butyl ether
ND	Nondetect
NESHAP	Emissions standards for hazardous air pollutants
NM	Not measured

OLD	Organic liquids distribution
O&M	Operating and maintenance
OPPT	Office of Pollution Prevention and Toxics
OSW	Office of Solid Waste
OTAQ	Office of transportation air quality
PAH	Polycyclic aromatic hydrocarbons
PBT	Persistent, bioaccumulative and toxic chemicals
PCB	Polychlorinated biphenyl
PE	Professional engineer
PCDD/F	Polychlorinated dibenzo-p-dioxins and furans
PIC	Product of incomplete combustion
POHC	Principle organic hazardous constituents
POPs	Persistent organic pollutants
QA/QC	Quality assurance/Quality control
QL	Quantitation limit
RA	Regional administrator
RCRA	Resource Conversation and Recovery Act
RFG	Reformulated gasoline
RREL	Risk Reduction Engineering Laboratory
SPCC	Spill prevention control and countermeasure
SOP	Standard operating procedures
SVOC	Semivolatile organic compounds
TAME	Tertiary-amyl methyl ether
TCDD	Tetrachlorodibenzodioxin
TEQ	Toxic equivalent
TFR	Turbulent flame reactor
THC	Total hydrocarbon
TRI	Toxics release inventory
VOC	Volatile organic compounds
VOST	Volatile organic sampling train
UDRI	University of Dayton Research Institute
WMPT	Waste minimization prioritization tool
WOE	Weight-of-evidence

Appendices

A. DRE versus CO/HC: Supplement to 1997 TSD
B. Analysis of Nondetect Organic Emissions
C. Outlier Analysis for Hazardous Waste Boiler Organic Emissions
D. Calculations for DF Comparative Risk Assessment
E. ECF Tank size and Number of Shipments
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I. Relative Hazard Categorization Scheme: WMPT Parameter Values for Constituents