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Interim Detailed Study Report for the Steam Electric Power Generating Point Source Category

U.S. Environmental Protection Agency
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Office of Water
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LIST OF ACRONYMS

API	American Petroleum Institute
ASTM	American Society for Testing and Materials
BART	Best available retrofit technology
BAT	Best available control technology economically achievable
BCT	Best conventional pollutant control technology
BLM	Bureau of Land Management
BOD_5	5-day biochemical oxygen demand
BPJ	Best professional judgment
BPT	Best practicable control technology currently available
CAA	Clean Air Act
$CaCO_3$	Limestone
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
$Ca(OH)_2$	Lime
$CaSO_3$	Calcium sulfite
CAVR	Clean Air Visibility Rule
CCH	Chlorine and Chlorinated-Hydrocarbon Manufacturing
CCR	Coal combustion residue
CCS	Combined cycle system
CCT	Clean Coal Technology
CFR	Code of Federal Regulations
Cl	Chlorine
Cl_2	Chlorine gas
COALQUAL	USGS's Coal Quality Database
COD	Chemical oxygen demand
CPO	Chlorine-produced oxidants
Cr	Chromium
CRC	Combined residual chlorine
Cu	Copper
CURC	Coal Utilization Research Council
CWA	Clean Water Act
DMRs	Discharge monitoring reports
DOE	U.S. Department of Energy
EIA	U.S. DOE's Energy Information Administration
ELGs	Effluent limitations, guidelines, and standards
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic precipitator
FAC	Free available chlorine
FAO	Free available oxidants
Fe	Iron
FGD	Flue gas desulfurization
FR	Federal Register
GPM	Gallons per minute
HRSGs	Heat recovery steam generators
IEP	Innovations for Existing Plants

LIST OF ACRONYMS (Continued)

IGCC	Integrated gasification combined cycle
lb-eq	Pound-equivalent
MDL	Method detection level
MGD	Million gallons per day
MGY	Million gallons per year
MSW	Municipal solid waste
MVR	Mechanical vapor recompression
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NEC	Not elsewhere classified
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NETL	U.S. DOE's National Energy Technology Lab
NH_3	Ammonia
$(NH_4)_2SO_4$	Ammonium sulfate
NH_4HSO_4	Ammonium bisulfate
NO	Nitrogen monoxide
NO_2	Nitrogen dioxide
NO_x	Nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NRC	National Research Council
NRECA	National Rural Electric Cooperative Association
NRMRL	U.S. EPA's National Risk Management Research Laboratory
NSPS	New source performance standards
OAP	Office of Atmospheric Programs
OAQPS	U.S. EPA's Office of Air Quality Planning and Standards
OAR	Office of Air and Radiation
OCPSF	Organic Chemicals, Plastics & Synthetic Fibers Manufacturing
OECA	U.S. EPA's Office of Enforcement and Compliance Assurance
O&G	Oil and grease
ORD	U.S. EPA's Office of Research and Development
OSW	U.S. EPA's Office of Solid Waste
OW	Office of Water
PCBs	Polychlorinated biphenyls
PCS	Permit Compliance System
POTWs	Publicly owned treatment works
ppm	Parts per million
PSES	Pretreatment standards for existing sources
PSNS	Pretreatment standards for new sources
RCRA	Resource Conservation and Recovery Act
RDF	Refuse-derived fuel
RICE	Reciprocating internal combustion engine
SCR	Selective catalytic reduction
SEGS	Solar Electric Generating Stations
SIC	U.S. Standard Industrial Classification
SMCRA	Subsurface Mining Control and Reclamation Act

LIST OF ACRONYMS (Continued)

SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
SO_3	Sulfur trioxide
TDS	Total dissolved solids
Total P	Total phosphorus
TRC	Total residual chlorine
TRI	Toxics Release Inventory
TRO	Total residual oxidants
TSS	Total suspended solids
TWF	Toxic-weighting factor
TWPE	Toxic-weighted pound equivalents
USCB	U.S. Census Bureau
USGS	U.S. Geological Survey
USWAG	Utility Solid Waste Activities Group
UWAG	Utility Water Act Group
ZLD	Zero liquid discharge
Zn	Zinc

1.0 INTRODUCTION

Section 304(m) of the Clean Water Act (CWA) requires EPA to develop and publish a biennial plan that establishes a schedule for the annual review and revision of national effluent limitations guidelines and standards (ELGs) required by Section 304(b). EPA last published an Effluent Guidelines Program Plan in 2004 [64 FR 53705; September 2, 2004].

During its 2005 screening-level analysis of discharges from categories with existing regulations, EPA determined that the Steam Electric Power Generating Point Source Category, regulated at 40 CFR 423 (i.e., the regulated steam electric industry), ranked second in discharges of toxic and nonconventional pollutants. For more information on the development of the category ranking, see the 2005 *Screening-Level Analysis* report [U.S. EPA, 2005a]. Because of these findings, EPA conducted a more detailed study of this category.

During this detailed study, EPA first verified that the pollutant discharges reported to the Permit Compliance System (PCS) and Toxics Release Inventory (TRI) for 2002 accurately reflect the current discharges of the industry. EPA also performed an in-depth analysis of the reported pollutant discharges, and reviewed technology innovation and process changes. Additionally, EPA evaluated certain electric power and steam generating activities that are similar to the processes regulated for the Steam Electric Power Generating Point Source Category, but that are not currently subject to ELGs.

In August 2005, EPA published its *Preliminary Effluent Guidelines Plan for 2006* [70 FR 51042; August 29, 2005] and the *Preliminary Engineering Report: Steam Electric Detailed Study* [U.S.EPA, 2005b]. Since that time, EPA continued to collect data and information about the steam electric industry and, in particular, focused its efforts on the following specific objectives for the study:

- To identify the key pollutants and sources of those pollutants discharged by the regulated steam electric industry.
- To identify and assess available pollution control technologies and best management practices within the industry to address significant pollutant discharges.
- To evaluate the wastewaters from certain activities not currently regulated by ELGs, which may be similar in nature to the waste streams regulated by 40 CFR 423. EPA examined the following types of waste streams and activities:
    - Wastewaters from the combustion/gas turbine portion of combined cycle systems (CCSs).
    - Wastewaters associated with facilities that generate electric power using steam to drive a turbine, but whose energy/heat source used to produce the steam is not a fossil or nuclear fuel. These energy sources may include combustible fuels, such as municipal solid

wastes, wood and wood wastes, and landfill gas, or renewable energy sources, such as solar power and geothermal energy.

— Wastewaters associated with steam supply facilities that generate steam for distribution and sale, but that do not primarily use that steam to drive a turbine and produce electric power.

— Wastewaters associated with facilities providing a combination of electric power and other utility services. EPA specifically focused the study on those combination utilities that generate electric power by using steam to drive a turbine.

— Wastewaters associated with industrial non-utilities that generate electric power using steam to drive a turbine, but that are not primarily engaged in distributing and selling that electric power. These industrial steam electric non-utilities provide auxiliary electric power to an industrial process (e.g., chemical manufacturing, petroleum refining). EPA's focus for these facilities is on the waste streams generated by the electric power-generating non-utilities, and not the other waste streams generated by the primary industrial processes at the facility.

EPA determined that the currently available data provide an incomplete picture of the wastewaters generated by the regulated steam electric industry; however, they do suggest that several process waste streams are primarily driving the pollutant loads discharged by these facilities and that control technologies and management practices capable of achieving significant pollutant reductions are technologically feasible.

EPA intends to continue its detailed study of the Steam Electric industry in its 2007/2008 planning cycle. The current evaluation allowed EPA to identify targeted areas of concern for which EPA needs to collect additional data. The focus of further study is expected to concentrate primarily on better characterizing pollutant sources and available pollution control technologies/practices for the pollutants responsible for the majority of the toxic-weighted pollutant loadings from steam electric facilities. One aspect of this further study will assess the significance of air-to-water cross media pollutant transfers associated with air pollution controls. In conducting this additional study, EPA's Office of Water will coordinate its efforts with ongoing research and other activities being undertaken by other EPA offices, including the Office of Research and Development (ORD), the Office of Solid Waste (OSW), and the Office of Air Quality Planning and Standards (OAQPS) and the Office of Atmospheric Programs (OAP), both in the Office of Air and Radiation (OAR).

EPA also investigated certain activities not currently regulated by the Steam Electric effluent guidelines, as described above. Based on the information in EPA's administrative record for this industry, EPA determined that revising the applicability of 40 CFR 423 to include these facilities is not warranted at this time.

This report, *Interim Detailed Study Report for the Steam Electric Power Generating Point Source Category* ("Detailed Study Report"; EPA-821-R-06-015; DCN 3401), describes the status of EPA's detailed study of the steam electric industry as of June 2006. It documents the data and information that EPA used to support decisions with respect to the current Steam Electric ELGs and the 2006 Effluent Guidelines Program Plan.

The report is organized into the following chapters:

- Chapter 2 discusses the data sources used in the detailed study;
- Chapter 3 presents a profile of the industry, including a description of the steam electric process, sources of wastewater, and available demographic data;
- Chapter 4 summarizes the existing regulations for this industry and other regulations currently under development;
- Chapter 5 discusses wastewater characteristics and selected wastewater control technologies and other best management practices used by the steam electric industry;
- Chapter 6 describes steam electric facilities and processes that utilize energy sources other than fossil or nuclear fuels;
- Chapter 7 presents a profile of the steam supply industry, including a process description, sources of wastewater, and available demographic data;
- Chapter 8 discusses combination utilities;
- Chapter 9 describes industrial non-utility steam electric processes and wastewater sources; and
- Chapter 10 presents the references cited in this report.

2.0 DATA SOURCES

This chapter describes the data sources EPA utilized for its detailed study of the steam electric industry[1]. EPA used data from three primary data sources: the U.S. Department of Energy's (DOE's) Energy Information Administration (EIA), the PCS, and the TRI. EPA also reviewed data from other regulations impacting steam electric facilities, as well as data provided by trade associations, vendors, and other sources.

It should be noted that EPA used data from a single calendar year whenever possible, to allow data from the multiple sources to be combined in the analyses. At the time this detailed study was initiated, EPA used 2002 data, the most recent TRI data available.

2.1 Department of Energy

DOE promotes scientific and technological innovation in support of its mission to advance the national, economic, and energy security of the United States. DOE's goals toward achieving this mission include applying advanced science and nuclear technology to the U.S.'s defense, promoting a diverse supply and delivery of reliable, affordable, and environmentally sound energy, advancing scientific knowledge, and providing for the permanent disposal of the U.S.'s high-level radioactive waste. In this detailed study of the steam electric industry, EPA used information on electric generating facilities from DOE's EIA data collection forms and obtained background information on the steam electric industry from various DOE research publications.

2.1.1 Energy Information Administration

EIA is a statistical agency of the DOE that collects information on existing U.S. electric generating facilities and associated equipment to evaluate the current status and potential trends in the industry. EPA used information from two of EIA's data collection forms: Form EIA-860, Annual Electric Generator Report, and Form EIA-767, Steam Electric Plant Operation and Design Report. These forms are discussed below.

Form EIA-860

Form EIA-860 collects information annually for all electric generating facilities that have or will have a nameplate rating of one megawatt (MW) or more, and are operating or plan to be operating within five years of the filing of the Annual Electric Generator Report. The data collected in Form EIA-860 are associated only with the design and operation of the generators at facilities [U.S. DOE, 2002a]. EPA used the following information from Form EIA-860 to characterize the steam electric industry:

- Company Name;
- Facility Name;

[1] The steam electric industry generally comprises all facilities that produce electricity using steam-driven turbines. Refer to Chapter 3 for additional information.

- North American Industry Classification System (NAICS) code;
- Nameplate Capacity - The maximum rated output of a generator;
- Prime Mover - The engine, turbine, water wheel, or similar machine that drives an electric generator;
- Energy Source - The primary source providing the power that is converted to electricity through chemical, mechanical, or other means; and
- Month and year of initial operation.

Form EIA-767

Form EIA-767 collects information annually from all electric generating facilities with a total existing or planned, organic-fueled or renewable steam electric generating unit that has a nameplate rating of 10 MW or larger. The data collected in Form EIA-767 is associated with the operation and design of the entire facility. EPA used Form EIA-767 primarily for information on the type of cooling systems used by the steam electric industry, as well as the number of facilities using wet scrubber flue gas desulfurization (FGD) [U.S. DOE, 2002b]. EPA used the following data elements from Form EIA-767:

- Type of system;
- Type of tower;
- Type of FGD system;
- Flow rates; and
- Source water.

One of the limitations of using data from Form EIA-767 is that the cooling system information is required only for facilities that have a nameplate capacity larger than 100 MW; therefore, not every facility reporting to Form EIA-767 provides information about their cooling system. Although no information was available from this source for smaller facilities, EPA was able to incorporate cooling system information for 51 facilities with a nameplate capacity less than 100 MW through Section 316(b) Cooling Water Intake Structures rulemaking support documents, as described in Section 2.2.4.

2.1.2 Other DOE Programs of Interest

DOE manages various programs that guide the research of novel technologies for coal-fired power plants. Programs found to be especially pertinent to the steam electric industry are described below:

- Clean Coal Technology (CCT) Program: This program is sponsored by DOE, the Electric Power Research Institute (EPRI)[2], and the Coal Utilization Research Council (CURC). The goals for the CCT Program

[2] Section 2.4.2 described additional research EPRI is conducting.

are to achieve near-zero emissions from coal-fired power plants and to efficiently capture and sequester carbon.

- Innovations for Existing Plants (IEP) Program: This program is managed by DOE's National Energy Technology Lab (NETL) and advances novel technologies for coal-fired power plants, including the control of mercury and nitrogen oxides (NO_x) and technologies to improve the quality of coal utilization by-products.

From the information published through these DOE research programs, EPA obtained background information on current steam electric technologies, specifically pollution control technologies for coal-fired steam electric facilities.

2.2 EPA and State Permitting Authorities

For this detailed study of the steam electric industry, EPA collected information from the Agency's databases, publications, and state permitting authorities. EPA obtained information on pollutant releases from the electric generating industry from the PCS and TRI databases, information on current permitting practices for the steam electric industry from a review of selected National Pollutant Discharge Elimination System (NPDES) permits, information from a survey of the industry conducted in support of the Section 316(b) Cooling Water Intake Structures rulemaking, and background information on the steam electric industry from documents prepared during the development and revision of the ELGs for the Steam Electric Power Generating Point Source Category, last promulgated in 1982.

2.2.1 Permit Compliance System

EPA's Office of Enforcement and Compliance Assurance (OECA) manages PCS, which is a national data system that contains permit, compliance, and enforcement status information on facilities with NPDES permits. Facilities that discharge wastewaters directly to surface waters of the United States are required to obtain NPDES permits from EPA or state permitting authorities. NPDES-permitted facilities submit Discharge Monitoring Reports (DMRs) to their permitting authorities in accordance with their permit requirements, and the permitting authorities input these DMR data to PCS.

The permitting authorities are required only to input DMR data for facilities that they judge to be *major* sources of pollutants (i.e., facilities that are likely to significantly impact receiving streams if they discharge without control). Thus, PCS identifies all facilities with NPDES permits, but does not contain pollutant discharge data for all of these facilities. Because permitting authorities are not required to input DMR data for *minor* sources, the data available for minor sources are limited in PCS.

EPA created the *PCSLoads2002* database [U.S. EPA, 2006a] using the PCS pollutant discharge data from 2002 and various database development tools. In addition to calculating pollutant mass loads, *PCSLoads2002* estimates the hazard of the pollutant mass loads by multiplying the pounds of pollutants discharged by the pollutant-specific toxic weighting factors (TWFs). This results in an estimate of toxic-weighted pound equivalents (TWPEs). *PCSLoads2002* uses the TWFs traditionally used in the ELG Program to quantify the relative toxicity of pollutant discharges. For additional information on the development of *PCSLoads2002*, see the *2005 Annual Screening-Level Analysis* report [U.S. EPA, 2005a].

EPA made modifications and updates to *PCSLoads2002* that were specific to the steam electric industry based on public comment and additional data review. The revised pollutant loads and concentrations presented in Chapter 5 reflect these changes. For additional information on these modifications and updates, see the memorandum entitled "Changes Made to the *PCSLoads2002* Database Based on Facility-Specific Comments" [ERG, 2006].

2.2.2 Toxics Release Inventory

The TRI database contains information on toxic chemical releases that are reported annually to EPA by facilities meeting size, industrial classification, and chemical activity criteria. These facilities report the amounts of toxic chemicals released to the environment, as well as the amounts of toxic chemicals transferred in wastes to off-site locations, including discharges to publicly owned treatment works (POTWs). The TRI chemical releases are reported as pounds per year.

Steam electric facilities are required to report to TRI if the facility meets all of the following criteria[3]:

- Number of Employees: A facility must have 10 or more full-time employees or their equivalent. EPA defines a "full-time equivalent" as a person who works 2,000 hours in the reporting year.

- Industrial classification: The operations of the facility are primarily classified within U.S. Standard Industrial Classification (SIC) codes 4911, 4931, or 4939 and the facility combusts coal and/or oil for the purpose of generating electric power for distribution in commerce.

- Activity Thresholds: A facility must conduct an activity threshold analysis for every chemical and chemical category on the current TRI list to determine whether it manufactures, processes, or otherwise uses each of those chemicals at or above the appropriate activity threshold.

Based on the above criteria, natural gas- or nuclear-powered electric power generating facilities are not required to report toxic chemical releases to EPA. If an electric power generating facility combusts any amount of coal or oil to generate electricity for distribution in commerce, the entire facility (including the non-coal/oil combustion processes) is subject to TRI reporting requirements. EPA considers kerosene and petroleum coke as "oil" for TRI reporting purposes [U.S. EPA, 2000].

EPA used the toxic chemical release data from the 2002 TRI reporting year to create the *TRIReleases2002* database [U.S. EPA, 2006b]. In this detailed study of the steam electric industry, EPA used *TRIReleases2002* to compute a TWPE for each TRI chemical

[3] All facilities meeting this criteria report to EPA, even if no releases of the toxic chemical occurred during the reporting year.

discharged with facility wastewaters. For additional information on TRI reporting and the development of *TRIReleases2002*, see the *2005 Annual Screening-Level Analysis* report [U.S. EPA, 2005a].

2.2.3 NPDES Permits and Fact Sheets

The CWA requires direct dischargers (i.e., industrial facilities that discharge process wastewaters from any point source into receiving waters) to control their discharges according to ELGs and water-quality-based effluent limitations within NPDES permits.

EPA reviewed selected NPDES permits and, where available, accompanying fact sheets to identify the sources of wastewater at steam electric facilities and to determine how the wastewaters are currently regulated (i.e., parameter limits and the basis for parameter selection). As part of EPA's NPDES permit review, Agency personnel contacted state permit writers to obtain additional information or clarify permit information. Information obtained from the NPDES permit review has been included in this report, where appropriate. The NDPES permits and fact sheets reviewed for the study are located at EPA Docket ID No. OW-2004-0032.

2.2.4 Section 316(b) - Cooling Water Intake Structures Supporting Documentation/Data

For the CWA section 316(b) Cooling Water Intake Structures rulemaking, EPA conducted a survey of steam electric utilities and steam electric non-utilities that use cooling water, as well as facilities in four other manufacturing sectors: Paper and Allied Products (SIC code 26), Chemical and Allied Products (SIC code 28), Petroleum and Coal Products (SIC code 29), and Primary Metals (SIC code 33). The survey requested the following types of information:

- General plant information, such as plant name, location, and SIC codes;
- Cooling water source and use;
- Design and operational data on cooling water intake structures and cooling water systems;
- Studies of the potential impacts from cooling water intake structures, conducted by the facility; and
- Financial and economic information about the facility.

Although the Section 316(b) survey was used to create guidelines for cooling water intake structures, the cooling water system information collected in the survey is useful for this study of the steam electric industry. EPA used the information provided by the Section 316(b) survey in the following analyses:

- Linking EIA facility information to the TRI and PCS discharges;
- Identifying the type of cooling systems used by facilities; and
- Identifying industrial non-utilities.

Refer to Section 4.2 of this report for additional information about the section 316(b) regulations.

2.2.5 Office of Research and Development

EPA's ORD is currently evaluating the impact of air pollution controls on the characteristics of coal combustion residues (CCRs). Specifically, ORD is studying the potential cross-media transfer of mercury and other metals from flue gas, fly ash, and other residues collected from coal-fired boiler air pollution controls and disposed of in landfills or surface impoundments, with the key route of release being leaching into groundwater or subsequent release into surface waters, re-emission of mercury, and bioaccumulation. ORD is also examining the use of CCRs in asphalt, cement, and wallboard production.

This research seeks to better understand potential impacts from disposal practices and beneficial use of CCRs. The research includes taking a holistic approach, calculating life-cycle environmental tradeoffs that compare beneficial use applications with and without using CCRs. The outcome of this research will help to identify potential management practices of concern where cross-media transfers may occur.

In addition, the ORD research is intended to provide methodologies and data for quantifying potential benefits and environmental tradeoffs from CCR utilization. Another outcome is the development and application of a leach testing framework that evaluates a range of materials and the different factors affecting leaching for the varying field conditions in the environment.

EPA's OW consulted with ORD during this industry study, including reviewing a February 2006 report [U.S. EPA, 2006c] to better understand the current research on CCRs and assess the potential for CCRs from air pollution controls to impact surface water quality. Sections 4.3 and 4.4 of this report include more information about air pollution control regulations and ongoing OSW rulemaking efforts to manage CCRs.

2.2.6 1974 and 1982 Technical Development Documents for the Steam Electric Power Generating Point Source Category

The 1974 *Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category* (hereinafter the 1974 Development Document) [U.S. EPA, 1974] and the 1982 *Development Document for Effluent Limitations Guidelines and Standards and Pretreatment Standards for the Steam Electric Point Source Category* (hereinafter the 1982 Development Document) [U.S. EPA, 1982] present the results of studies of the steam electric industry that EPA conducted in developing the Steam Electric ELGs. These development documents contain findings, conclusions, and recommendations on control and treatment technology relating to discharges from steam electric facilities. In this detailed study, EPA used the information presented in the 1974 and 1982 Development Documents for historical background on the Steam Electric ELGs, for information on sources of pollutants, and as a point of reference.

2.2.7 1996 Preliminary Data Summary for the Steam Electric Power Generating Point Source Category

EPA prepared the *1996 Preliminary Data Summary for the Steam Electric Power Generating Point Source Category* (hereinafter the Preliminary Data Summary) to provide technical support for a possible revision of the Steam Electric ELGs [U.S. EPA, 1996]. This Preliminary Data Summary contains descriptions of the steam electric process and information on the pollutants released in each of the different types of waste streams. Additionally, the Preliminary Data Summary includes information regarding changes that were beginning to occur in the steam electric industry at the time of publication. EPA used the data and information presented in the 1996 Preliminary Data Summary as a point of reference in this detailed study.

2.2.8 Office of Enforcement and Compliance Assistance Sector Notebook

The OECA Sector Notebook, *Profile of the Fossil Fuel Electric Power Generation Industry* [U.S. EPA, 1997], contains the following information:

- Industry profile using 1995 data;
- Industrial process descriptions;
- Chemical releases and transfers;
- Pollution prevention opportunities; and
- Regulatory summary.

In this detailed study of the steam electric industry, EPA supplemented data from EIA, PCS, and TRI with background information from the Sector Notebook.

2.3 <u>Department of Commerce Economic Census</u>

The Economic Census provides a detailed portrait of the U.S. economy once every five years. The 2002 Economic Census covers nearly all of the U.S. economy in its basic collection of facility statistics, and provides the following information by NAICS code:

- Number of companies;
- Number of establishments (i.e., facilities);
- Number of employees; and
- Number of establishments by size range, based on number of employees.

The Economic Census provides an upper limit of the number of facilities performing steam electric generating operations in the United States. The Census data overstate the steam electric numbers by including electric generating facilities that do not specifically use steam turbines (e.g., facilities using only gas turbines). For this reason, EPA used the Census data only as a point of reference in this detailed study.

2.4 <u>Electric Power Industry, Vendors and Other Sources</u>

EPA obtained additional information on steam electric processes, technologies, wastewaters, pollutants, and regulations from the following sources.

2.4.1 Utility Water Act Group

The Utility Water Act Group (UWAG) is a trade association that represents the utility electricity producers. Since early 2005, EPA staff have met and corresponded with representatives of UWAG on multiple occasions to discuss the detailed study and certain inconsistencies and gaps in PCS data. UWAG has provided the following types of data and information regarding the steam electric industry:

- Reports related to chlorine use, including a comparison of continuous and intermittent exposure of four species of aquatic organisms to chlorine and the formation and fate of trihalomethanes in power plant cooling water systems;
- A list of National Rural Electric Cooperative Association (NRECA) members;
- Comments, including facility-specific corrections to the *PCSLoads2002* database;
- The *Utility Industry Action Plan for the Management of Coal Combustion Products* [USWAG, 2006], submitted to EPA's OSW by the Utility Solid Waste Activities Group (USWAG);
- American Coal Ash Association's *Coal Combustion Products Production and Use Survey (2001-2003)* [ACAA, 2003];
- UWAG voluntary survey data including: (1) biocide management techniques; (2) retrofit of dry fly ash handling technologies; (3) typical wastewater discharges from combined cycle facilities; and (4) beneficial use of ash;
- Discussion of representativeness of survey data; and
- Correspondence responding to questions on technologies and practices in use by industry.

Information provided by UWAG to EPA as of June 2006 has been included in this report, where appropriate. For more information regarding specific information that has been provided to EPA, see Docket ID No. OW-2004-0032.

2.4.2 Electric Power Research Institute

EPRI conducts research on issues associated with energy and the environment that are facing the electric power industry. Founded in 1973 as a private, public-interest, not-for-profit organization, EPRI manages a science and technology program that addresses current issues as well as future technology options for nearly every aspect of electricity generation, delivery, and use. EPRI's specific programs of interest to this study include:

- The *Technology Innovation* research and development program that advances novel technologies in all areas of the electricity sector;

- The *Mercury, Metals, and Organics in Aquatic Environments* program that mitigates the risks associated with these pollutants in aquatic environments; and

- The *Integrated Facilities Water Management* program that delivers information, technologies, and practical tools and guidelines for biological fouling control, wastewater treatment, advanced cooling alternatives, and water recycling and reuse at industrial facilities.

EPA gained insight into how issues and technologies related to the steam electric industry are currently being researched through EPRI's published information. Specifically, EPA obtained background information on the pollutants of interest to this steam electric detailed study.

2.4.3 U.S. Geological Survey's COALQUAL Database

Since the middle 1970s, the U.S. Geological Survey (USGS) has maintained a national coal quality database, containing data compiled on more than 13,000 coal samples collected by USGS and cooperative state geological surveys. For each sample, 136 parameters are recorded, including data on location and sample description, analytical data from American Society for Testing and Materials (ASTM) tests, and USGS tests for major, minor, and trace elements. The COALQUAL database [USGS, 1998] contains coal quality data for 7,430 coal samples that represent complete-bed thicknesses at various localities. All elemental data are reported in parts-per-million (ppm). EPA used data from the COALQUAL database to identify constituents of coal and the range of concentrations associated with certain metals, such as boron and mercury.

2.4.4 National Research Council

In response to a request from Congress regarding concern over the use of CCRs as backfill for mining operations, EPA commissioned an independent study of the health, safety, and environmental risks associated with this practice. The National Research Council (NRC) established the Committee on Mine Placement of Coal Combustion Wastes, which addressed the potential issues of using CCRs in mines. For this detailed study, EPA reviewed a prepublication copy of NRC's report, *Managing Coal Combustion Residues in Mines* [NRC, 2006]. This NRC report provides background information for this detailed study on potential cross-media transfers of pollutants from CCR solids/slurries to water. Section 4.4 of the detailed study report contains additional summary information about current EPA solid waste rulemaking efforts.

2.4.5 Wastewater Treatment Equipment Vendors

EPA contacted companies that manufacture, distribute, or install various components of pollutant removal systems, including dehalogenation systems and pollutant mitigation systems. EPA obtained information about the operation of these systems and the type and cost of the equipment used.

2.4.6 Literature and Internet Searches

EPA conducted internet and literature searches to obtain information on the steam electric industry. These searches focused on various aspects of the steam electric process (those regulated by the Steam Electric ELGs and certain processes outside the scope of the ELGs), wastewaters and pollutants originating from these steam electric processes, and existing regulations for steam electric facilities. Information obtained from the internet and literature searches has been included in this report, where applicable.

3.0 STEAM ELECTRIC INDUSTRY PROFILE

This chapter describes the Steam Electric Power Generating Point Source Category (as defined at 40 CFR 423.10) in relation to the electric generating industry as a whole.

Electric generating facilities use various types of prime movers driven by an energy source to produce electricity. DOE's EIA defines a prime mover as the engine, turbine, water wheel, or similar machine that drives an electric generator, or a device that converts energy to electricity directly (e.g., photovoltaic solar and fuel cell(s)) [U.S. DOE 2006a]. The types of prime movers include steam turbines, gas turbines, internal combustion engines, combined-cycle systems, hydraulic turbines, and others.

For the purposes of discussions presented in this report, EPA is using the following definitions for various subgroups of electric generating facilities:

- *Electric generating industry*: Comprises utilities and non-industrial non-utilities primarily classified within SIC codes 4911, 4931, and 4939. Section 3.1.1 describes utilities and non-industrial non-utilities in greater detail.

- *Steam electric industry*: Comprises electric generating facilities (as defined above) that produce electricity for distribution and sale using steam to drive a turbine/electricity generator.

- *Regulated steam electric industry*: Comprises steam electric facilities (as defined above) within the Steam Electric Power Generating Point Source Category, as defined at 40 CFR 423.10. These facilities primarily utilize fossil or nuclear fuels to drive a steam turbine used to produce electricity for distribution and sale.

3.1 Overview of the Electric Generating Industry

This chapter describes the types of facilities that compose the overall electric generating industry. As described above, the regulated steam electric industry is included within this general industrial sector.

3.1.1 Types of Facilities within the Electric Generating Industry

Electric generating facilities may be categorized as one of the following types:

1. *Utility*: A corporation, person, agency, authority, or other legal entity or instrumentality that owns and/or operates facilities for the generation, transmission, distribution, or sale of electric energy for use primarily by the public. Utilities provide electricity within a designated franchised service area and file forms listed in 18 CFR Part 141. Per EIA, facilities that qualify as cogenerators or small power producers under the Public Utility Regulatory Policies Act are not considered electric utilities [U.S. DOE, 2006a].

2. *Non-industrial non-utility*: A corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not an electric utility. Non-utility power producers include qualifying cogenerators, qualifying small power producers, and other non-utility generators (including independent power producers) without a designated franchised service area, and that do not file forms listed in 18 CFR Part 141 [U.S. DOE, 2006a]. Like utilities, non-industrial non-utilities' primary purpose is producing electric power for distribution and sale.

3. *Industrial non-utility*: Industrial non-utilities are similar to non-industrial non-utilities except their primary purpose is not the distribution and sale of electricity. This category includes electric generators that are colocated with other manufacturing activities such as chemical manufacturing or pulp and paper mills.

The applicability of the existing Steam Electric ELGs includes establishments *"…primarily engaged in the generation of electricity for distribution or sale…"* as defined at 40 CFR 423.10. As such, the electric generating industry, including regulated steam electric facilities, comprises both utilities and non-industrial non-utilities. Industrial non-utilities are not within the scope of the existing Steam Electric ELGs applicability, since they are not primarily engaged in producing electricity for distribution or sale.

3.1.2 Industrial Classifications of the Electric Generating Industry

The *electric generating industry* is generally categorized by three SIC codes:

- *4911 – Electric services*: Establishments engaged in the generation, transmission, and/or distribution of energy for sale.

- *4931 – Electric and other services combined*: Establishments primarily engaged in providing electric services in combination with other services when the electric services are the major part of the services, but are less than 95 percent of the total services.

- *4939 – Combination utilities, not elsewhere classified (NEC)*: Establishments primarily engaged in providing combinations of electric, gas, and other services, not elsewhere classified.

In 1997, the SIC system was replaced by NAICS. SIC codes 4911, 4931, and 4939 are now captured under NAICS code 2211 – Electric Power Generation, Transmission, and Distribution, which includes establishments that may perform one or more of the following activities:

1. Operate generation facilities that produce electric energy;

2. Operate transmission systems that convey the electricity from the generation facility to the distribution system; and

3. Operate distribution systems that convey electric power received from the generation facility or the transmission system to the final consumer [USCB, 2002].

The following specific NAICS codes apply to steam electric facilities:

- 221112 – Fossil Fuel Electric Power Generation;
- 221113 – Nuclear Electric Power Generation; and
- 221119 – Other Electric Power Generation.

It should be noted that these SIC/NAICS codes include all electric generating facilities, not just steam electric facilities. For example, some of the facilities included in SIC 4911 generate electricity solely by way of combustion/gas turbines or hydroelectric turbines (i.e., steam is not used to move the turbine).

Industrial non-utilities are not categorized within the electric generating SIC and NAICS codes described above, since their primary purpose is not the distribution or sale of electricity. Industrial non-utilities provide electrical power to the industrial operation with which they are typically colocated. As such, these facilities tend to identify themselves within the SIC or NAICS code of the primary industrial operation performed at the site.

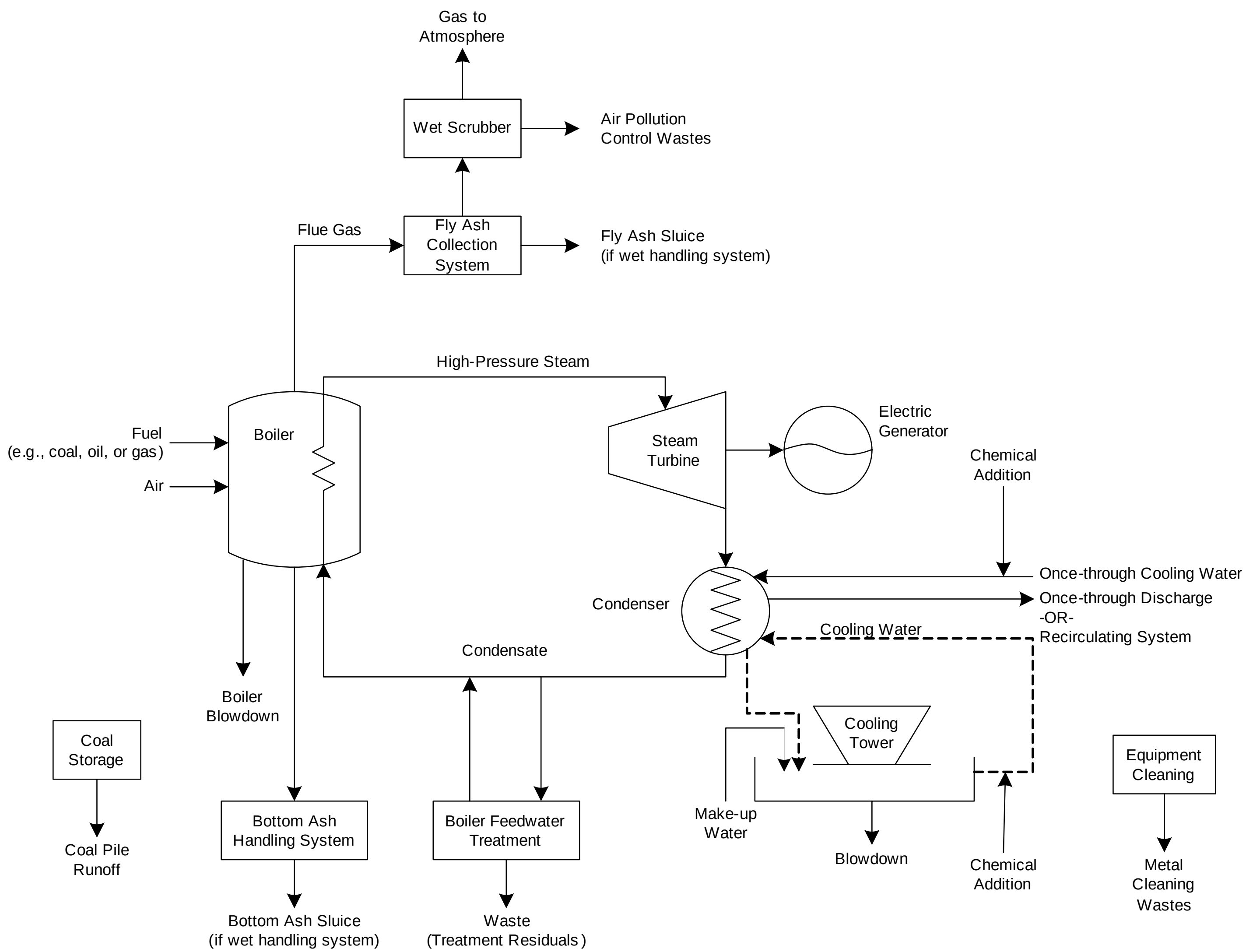
Because industrial non-utilities are not included in the regulated steam electric industry, they are not included in the information presented in this chapter, but are discussed in greater detail in Chapter 9 of this report.

3.2 General Description of Steam Electric Processes and Wastewater Sources

This section describes the steam electric generating process and the wastewater streams that are generated by each of the primary unit operations. This section is divided into discussions of the stand-alone steam electric process and that used by CCSs.

3.2.1 Stand-Alone Steam Electric Process and Wastewater Sources

Steam electric facilities generate electricity using a process that includes: 1) a steam generator (i.e., boiler); 2) a steam turbine/electrical generator; and 3) a condenser. Figure 3-1 illustrates the stand-alone steam electric process, in which a combustible fuel is used as the energy source to generate steam. The existing Steam Electric ELGs specifically regulate wastewaters discharged by steam electric facilities that use fossil-type fuel (e.g., coal, oil, or gas) or nuclear fuel to generate the steam. However, other fuel sources such as municipal solid wastes or wood wastes may also be used to produce the steam used in a steam electric process. Chapter 6 of this report discusses steam electric processes that use alternative fuel sources.



Sources: U.S. EPA, 1996 and U.S. EPA, 1997

Figure 3-1. Steam Electric Process Flow Diagram

As shown in Figure 3-1, fuels are fed to a boiler where they are combusted to generate steam. Boilers may have superheaters, reheaters, economizers, and air heaters to improve efficiency. The high-temperature, high-pressure steam leaves the boiler and enters the turbine generator. As it moves from the high-pressure boiler to the low-pressure condenser, the steam drives the turbine blades. During the process, the steam expands, and the lower-pressure steam enters the condenser, where it is condensed by the cooling water flowing through condenser tubes. The condensation process creates the low pressure required to increase the efficiency of the turbine. The condensate travels back to the boiler where it is reheated for use in the turbine [U.S. EPA, 2005b].

The steam cycle described above, known as the Rankine cycle, is referred to at 40 CFR 423.10 as the "steam water system" and is referred to throughout the remaining sections of this report as the "steam/water system." The 1974 Development Document refers to this cycle as the "water-steam cycle" and includes in its description the following major stages: steam generation; conversion of steam into mechanical energy in a turbine; steam condensation; conversion of mechanical energy into electrical energy by electrical generator; and the reintroduction of condensed steam into the boiler. The 1974 Development Document states that the steam exiting the turbine "could be exhausted directly to the atmosphere thus avoiding the requirement for condensers or condenser cooling water, but with poor cycle efficiency and a requirement for large quantities of high purity water" [U.S. EPA, 1974].

Instead of being exhausted, the noncondensed, low-pressure steam exiting a turbine from a steam electric process may be used in other processes, such as with cogeneration facilities[4]. In these cases, the spent steam is typically condensed downstream of the steam electric process at the point of use, which maintains the efficiency of the steam turbine. The wastewaters from these separated condensation stages may not be permitted as part of the steam electric process. Some of the industrial non-utilities discussed in Chapter 9 are cogeneration facilities. It is possible that some of the alternative-fueled steam electric facilities discussed in Chapter 6 are also cogeneration facilities.

The nuclear-fueled steam electric process uses the same steam/water system as described above for the stand-alone steam electric process; however, the process differs in that nuclear fission within a reactor core gives off the heat required for steam generation. No fuel is combusted and no ash is generated in a nuclear-fueled steam electric process. Instead, heat is transferred from the reactor core by creating steam in boiling water reactors or creating superheated water in pressurized-water reactors. Wastewaters from nuclear reactors may contain radioactive material. The steam turbine/electric generator and condenser portions of the nuclear-fueled steam electric process are the same as those described in this section for the stand-alone steam electric process [U.S. DOE, 2006b].

The following subsections describe the wastewaters associated with the stand-alone steam electric process and briefly discusses the types of pollutants that are typically present in these wastewaters. Chapter 5 of this report discusses in detail the pollutants found in steam electric process wastewaters.

[4] A *cogeneration facility* is defined as "a generating facility that produces electricity and another form of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes" [U.S. DOE, 2006a].

3.2.1.1 Fly and Bottom Ash Sluice

Combusting coal and oil in steam electric boilers produces a residue of the noncombustible constituents of the fuel that is referred to as ash. The ash consisting of heavy particles that collect at the bottom of the boiler is referred to as bottom ash. The ash consisting of finer particles that are light enough to be transferred by the flue gas is referred to as fly ash. Fly ash may be collected in an economizer, air heater, or particulate control equipment. Fly ash and bottom ash may be handled in a wet or dry fashion and may be transferred together or separately. Wet handling systems produce slurries of ash, referred to as sluices, that are typically transferred to wet surface impoundments. Ash handled in a dry fashion is typically transferred to landfills. Coal-fired facilities typically generate large quantities of both fly and bottom ash. Oil-fired facilities typically produce less ash than coal-fired facilities, and most of that is fly ash. Natural gas-fired facilities do not generate ash. The characteristics of ash depend on the type of fuel combusted, how it is prepared prior to combustion, and the operating conditions of the boiler. Fly and bottom ash sluices typically contain heavy metals, including priority pollutants [U.S. EPA, 1982].

3.2.1.2 Metal Cleaning Wastes

According to 40 CFR 423.11, "The term metal cleaning waste means any wastewater resulting from cleaning [with or without chemical cleaning compounds] any metal process equipment, including, but not limited to, boiler tube cleaning, boiler fireside cleaning, and air preheater cleaning." Chemicals are used to remove scale and corrosion products that accumulate on the boiler tubes and retard heat transfer. The major constituents of boiler cleaning wastes are the metals of which the boiler is constructed, typically iron, copper, nickel, and zinc. Boiler firesides are commonly washed with a high-pressure water spray against the boiler tubes while they are still hot. Fossil fuels with significant sulfur content will produce sulfur oxides that adsorb on air preheaters. Water with alkaline reagents is often used in air preheater cleaning to neutralize the acidity due to the sulfur oxides, maintain an alkaline pH, and prevent corrosion. The types of alkaline reagents used include soda ash, caustic soda, phosphates, and detergent.

3.2.1.3 Once-Through Cooling Water

In the steam electric process, a constant flow of cooling water is required to maintain steam condensation and a low pressure in the condenser. In once-through cooling water systems, the cooling water is withdrawn from a body of water, flows through the condenser, and is discharged back to the body of water. Figure 3-2 presents a diagram of a once-through cooling system. Steam electric facilities using a once-through system use large amounts of water, with an average flow rate of approximately 230 million gallons per day (MGD) per cooling water system[5] [U.S. EPA, 2006b]. Facilities may add chlorine or other biocides to the water to control the biofouling on the condenser tubes. The biocides kill the microbiological species that build up on the condenser tubes to allow for efficient heat transfer. Chapter 5

[5] EPA calculated a discharge rate of 230 MGD from a once-through cooling system using PCS flow data available for 64 facilities and 80 waste streams identified as once-through cooling water [U.S. EPA, 2006b]. The 1982 Development Document states that the average flow rate through a once-through cooling system was 305 MGD, based on industry survey data [U.S. EPA, 1982]. The 1996 Preliminary Data Study states that the once-through cooling water flow rate for a 1,150-MW coal-fired power plant is approximately 1,440 MGD [U.S. EPA, 1996].

discusses in more detail the steam electric industry's use of biocides and the technologies and practices used to minimize their discharge.

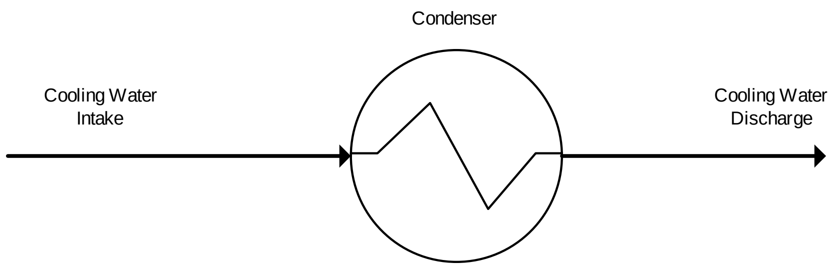


Figure 3-2. Diagram of a Once-Through Cooling System

3.2.1.4 Recirculating Cooling Tower Blowdown

A recirculating cooling system recirculates the cooling water required to maintain steam condensation and a low pressure in the condenser. After the water passes through the condenser, the heated water is typically sent to a cooling tower to lower the temperature of the water. The heated water enters the cooling tower at the top and falls down the packing material in the tower. Air flows upward through the tower, and as the air contacts the droplets of water, some of the water evaporates. The high surface area of the packing material enhances evaporation. As water evaporates, the latent heat required to evaporate the water is transferred from the cooling water to the air, cooling the water. Because some of the water evaporates, the cooling water flow rate is decreased during the process. Additionally, a small amount of water must be discharged periodically to control the build-up of solids, which is referred to as "cooling tower blowdown." Therefore, fresh make-up water is added to the system to keep the flow rate constant.

Figure 3-3 presents a diagram of a recirculating cooling system. Steam electric facilities using a recirculating system use much smaller amounts of water than facilities using once-through cooling systems, with an average flow rate of approximately 6.04 MGD per cooling water system[6] [U.S. EPA, 2006b]. EPA estimated that recirculating systems require only about five percent of the water that once-through systems require [U.S. EPA, 1982]. Some of the available data suggest that recirculating systems may discharge less than one percent of that from once-through systems (refer to Footnotes 5 and 6).

[6] EPA calculated a flow rate of 6.04 MGD for discharges from a recirculating cooling system using PCS flow data available from 111 facilities and 174 waste streams identified as cooling tower blowdown [U.S. EPA, 2006b]. The 1982 Development Document stated that the average blowdown flow rate from a recirculating cooling system was 0.94 MGD, based on industry survey data [U.S. EPA, 1982]. The 1996 Preliminary Data Summary stated that the cooling tower blowdown flow rate from a 1,150-MW coal-fired power plant ranges from 13.6 MGD to 36.6 MGD, depending on the cycle of concentration (i.e., number of times the water is reused in the system prior to blowdown) [U.S. EPA, 1996].

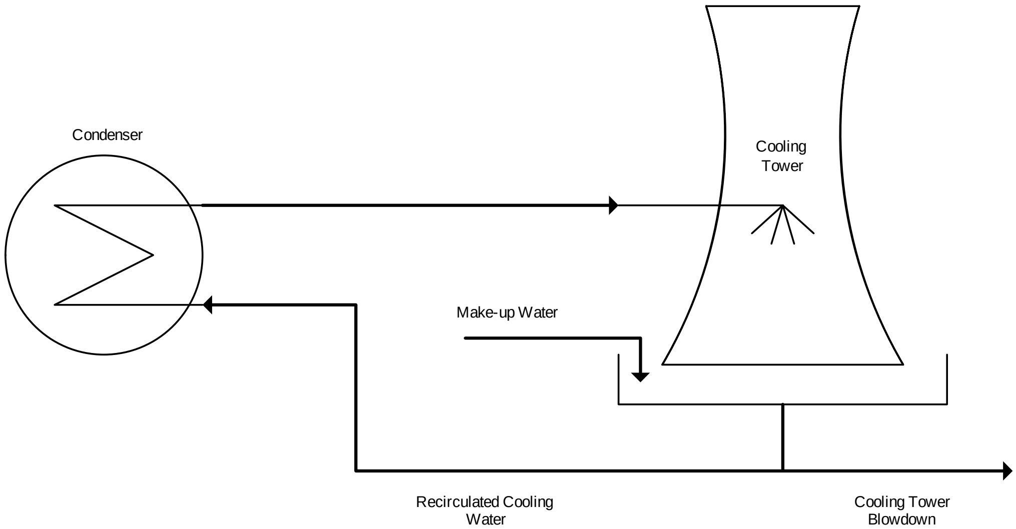


Figure 3-3. Diagram of a Recirculating Cooling System

As in once-through systems, facilities may add chlorine, other oxidizing biocides, or nonoxidizing biocides to recirculating systems to control the biofouling on the condenser tubes and the cooling tower packing material. Chapter 5 discusses in more detail the steam electric industry's use of biocides and the technologies and practices used to minimize their discharge.

3.2.1.5 Coal Pile Runoff

Coal-fueled steam electric facilities typically maintain an outdoor reserve of coal. Rainwater can dissolve inorganic salts or cause chemical reactions in coal storage piles and carry away pollutants in the runoff. The quantity of runoff depends upon the amount of rainfall, and the amount of contaminants generated depends upon residence time of water within the coal pile. Coal pile runoff is typically acidic due to the oxidation of iron sulfide, which produces sulfuric acid, and ferric hydroxide or ferric sulfate. Coal pile runoff may contain high concentrations of copper, iron, aluminum, nickel, and other constituents present in coal [U.S. EPA, 1982].

3.2.1.6 Air Pollution Control Wastes

Due to the new air regulations for the steam electric industry (Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR), discussed in Chapter 4), EPA expects that the use of wet air pollution control devices will increase at steam electric facilities. The two air pollution control devices that will likely be installed to meet the requirements of the new CAIR rule are FGD (for sulfur dioxide (SO_2) control), and selective catalytic reduction (SCR) (for control of NO_x). These two processes are described in the following subsections.

Flue Gas Desulfurization

FGD systems are used by power plants to control the SO_2 emissions from the facility. Wet scrubber systems are the most common; however, dry and spray dry FGD systems also exist [U.S. EPA, 2003]. This detailed study focused on wastewaters from wet FGD systems only.

Wet scrubbers work by contacting the gas streams with a liquid stream containing a sorbent, which effects mass transfer. The sorbents typically used for SO_2 absorption are lime ($Ca(OH)_2$) and limestone ($CaCO_3$). Equations 3-1 and 3-2 show the reactions that occur between these sorbents and SO_2, producing calcium sulfite ($CaSO_3$).

$$CaCO_{3\,(s)} + SO_{2\,(g)} \rightarrow CaSO_{3\,(s)} + CO_{2\,(g)} \qquad (3\text{-}1)$$

$$Ca(OH)_{2\,(s)} + SO_{2\,(g)} \rightarrow CaSO_{3\,(s)} + H_2O_{\,(l)} \qquad (3\text{-}2)$$

In some wet systems (e.g., limestone forced oxidation), the $CaSO_3$ is oxidized to produce gypsum ($CaSO_4$*$2H_2O$):

$$CaSO_{3\,(s)} + \tfrac{1}{2}\,O_{2\,(g)} + H_2O_{\,(l)} \rightarrow CaSO_{4\,(s)}{*}H_2O_{\,(s)} \qquad (3\text{-}3)$$

While these systems are more costly to operate, they afford large coal-fired plants benefits beyond the traditional wet scrubber system [U.S. EPA, 2003]. Unlike $CaSO_3$, which must typically be disposed of in landfills or surface impoundments, gypsum can be marketed for use in building materials (e.g., wallboard) [U.S. EPA, 2006c].

Typically, FGD systems can remove over 90 percent of the SO_2 in the flue gas. During the scrubbing process, metals and other particulates, including boron, mercury[7], and selenium, that were not removed from the flue gas stream by the electrostatic precipitators (ESPs) may be transferred to the scrubber blowdown. The average flow rate for FGD scrubber blowdown is approximately 0.35 MGD[8]. Figure 3-4 presents a diagram of an FGD system.

Regulations that limit the emissions of SO_2 and promote the use of wet scrubbers have the potential to create new wastewater streams at electric utilities. For example, wet FGD systems create a sludge by-product that is generally between 5 and 10 percent solids [U.S. EPA, 2006c], which may require dewatering prior to disposal or processing for reuse.

[7] ESPs capture particulate-bound mercury and FGD systems capture soluble mercury compounds. Available data indicate that elemental mercury may be oxidized in an SCR unit (particularly when bituminous coal is being used). This enhances the amount of oxidized mercury in the gas stream that may then be removed in the downstream wet FGD system [U.S. EPA, 2005c].

[8] EPA calculated a flow rate of 0.35 MGD for discharges from FGD scrubber blowdown using PCS flow data available from 10 waste streams identified as being associated with FGD [U.S. EPA, 2006a]; however, available data on FGD wastewaters is limited. FGD system information was reported by 183 steam electric facilities to the EIA in Form EIA-767 [U.S. DOE, 2002b]. EPA also estimates that steam facilities with FGD systems account for approximately 33 percent of the total U.S. steam electric capacity, based on information collected from the electric generating industry [U.S. EPA, 2006d]. Some facilities that have FGD may commingle the waste stream with the ash pond wastewater, making it difficult to identify these specific waste streams in PCS. FGD wastewaters are currently regulated among the *low-volume wastes* generated at steam electric facilities [40 CFR 423.11(b)].

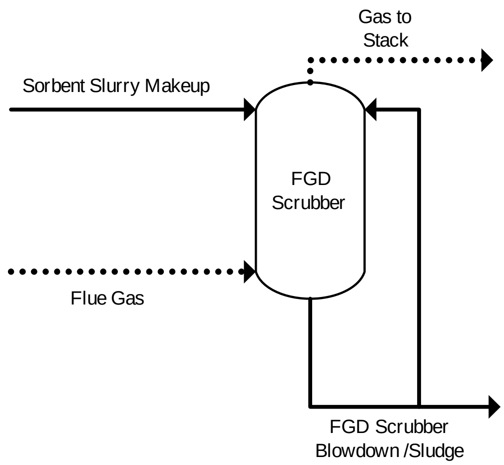


Figure 3-4. Flue Gas Desulfurization (FGD) System

During the 1982 rulemaking, EPA identified FGD wastes as a potential waste stream for regulation. At the time, there were approximately 34 facilities that had FGD systems and another 42 systems that were under construction [U.S. EPA, 1982]. From the data collected for the rulemaking, EPA concluded that there were insufficient data to characterize the pollutant loadings from FGD processes and that additional studies would be needed.

EPA subsequently obtained data from Form EIA-767, and identified 183 steam electric plants that used a wet scrubber FGD system in the United States in 2002 [U.S. DOE, 2002b]. EPA estimates that the use of wet SO_2 scrubbers will double by 2015 due to the CAIR [U.S. EPA, 2006d].

Selective Catalytic Reduction

SCR is a technology used to control NO_x emissions in the flue gas from the boiler. In SCR, ammonia (NH_3) is injected into the flue gas upstream of a catalyst, such as vanadium or titanium. The NO_x in the flue gas (comprising mainly nitrogen monoxide (NO) with lesser amounts of nitrogen dioxide (NO_2)) reacts with the NH_3 in the presence of oxygen and the catalyst to form nitrogen and water:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6\ H_2O \quad (3\text{-}4)$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O \quad (3\text{-}5)$$

In addition to these primary reactions, a fraction of the SO_2 in the flue gas may be oxidized to sulfur trioxide (SO_3), and other side reactions may produce ammonium sulfate ($(NH_4)_2SO_4$) and ammonium bisulfate (NH_4HSO_4) as by-products:

$$SO_2 + \tfrac{1}{2}\ O_2 \rightarrow SO_3 \quad (3\text{-}6)$$

$$2NH_3 + SO_3 + H_2O \rightarrow (NH_4)_2SO_4 \quad (3\text{-}7)$$

$$NH_3 + SO_3 + H_2O \rightarrow NH_4HSO_4 \quad (3\text{-}8)$$

These by-products can foul and corrode downstream equipment. The extent to which they are formed depends upon various factors within the process, including the sulfur content of the coal used in the boiler and the amount of excess NH_3 in the system. Unreacted NH_3 present in the flue gas from the SCR is commonly termed *ammonia slip* [CCT, 1997].

Facilities may use different configurations based on the particular operations of the system, including placing the SCR upstream of the air heater[9] and other emission control devices such as FGD and particulate controls (e.g., ESP). Although not directly associated with SCR, there are waste streams impacted by this technology, specifically FGD wastewaters and air heater wash water. As previously explained, unreacted NH_3 (i.e., ammonia slip) and SO_3 by-product creates $(NH_4)_2SO_4$ and NH_4HSO_4, which can deposit in the air heater and must be removed through periodic washes. Ammonia slip is also removed in ESP ash and in the FGD slurry. Since NH_3 is soluble, it will likely partition into the wastewater discharged from the facility [Wright, 2003].

In addition to reducing the ammonia slip, installing an SO_3 removal system before the air heater may further reduce the amount of $(NH_4)_2SO_4$, and NH_4HSO_4 formed and deposited in the air heater and, consequently, the amount of NH_3 in the air heater wash water [Wright, 2003].

3.2.1.7 Wastewaters from Boiler Feedwater Treatment

Steam electric facilities treat boiler feedwater to prevent scale formation. Suspended and dissolved solids are removed from the boiler feedwater using clarification, filtration, ion exchange, reverse osmosis, evaporation, or softening.

Clarification agglomerates solids in a stream and separates them by settling. Solids produced in the clarification process include sulfates, chlorides, and carbonates. Filtration may be used alone or with another treatment process to remove suspended solids from the boiler feedwater. Ion exchange is the most common method of treating boiler feedwater because it can remove all mineral salts in one unit. The process uses a bed of electrically charged cationic or anionic resin beads to attract chemical ions of the opposite charge. A solution is used to backwash, or "regenerate," the bed. The waste solution from the regeneration process typically does not contain significant amounts of suspended solids, but does contain sulfates and carbonates that precipitate readily. The softening process uses lime and/or soda ash to precipitate chemicals in the boiler feedwater: calcium precipitates as calcium carbonate, and magnesium precipitates as magnesium hydroxide. The evaporation process purifies boiler feedwater through vaporization and condensation. Evaporation wastes may be high in suspended solids. In the reverse osmosis process, a semipermeable membrane, which is permeable to water and impermeable to salt, separates two solutions of different salt concentrations. High pressure (higher than osmotic pressure) is applied to one of the solutions, which causes fresh water to pass through the membrane, and thus causes one solution to become more saline and the other to become less saline [U.S. EPA, 1982].

[9] The air preheater utilizes the heat contained in the flue gas to increase the temperature (via heat exchange) of the air injected into the boiler for combustion.

3.2.1.8 Boiler Blowdown

In drum-type boilers, in which steam is in equilibrium with boiler water, boiler water impurities are concentrated in the liquid phase. A small amount of water must be discharged periodically from drum-type boilers to control the build-up of solids, both dissolved and suspended. This discharge, which may be continuous or intermittent, is referred to as "boiler blowdown."

The sources of impurities in boiler blowdown are the intake water, internal corrosion of the boiler, and chemicals added to the boiler system. Impurities from the intake water are typically soluble inorganic species (e.g., Na^+, K^+, Cl^-, and SO_4^{-2}) and precipitates containing calcium and magnesium cations. Boiler corrosion typically contributes soluble and insoluble species of iron, copper, and other metals to the boiler water. Steam electric facilities add various chemicals to the boiler feed water to control corrosion, scale formation, pH, and solids deposition. These chemical additives may contribute chromium, copper, phenol, phosphate, and other chemical species to the boiler water [U.S. EPA, 1982].

3.2.1.9 Other Low-Volume Wastewaters

In addition to wet scrubber air pollution control systems, boiler feedwater treatment systems, and boiler blowdown, the definition of low-volume wastewater sources at 40 CFR 423.11 includes laboratory and sampling streams, floor drains, cooling tower basin cleaning wastes, and recirculating house service water systems.

3.2.2 Combined Cycle System Process and Wastewater Sources

Some electricity generators use CCSs to produce electricity. A CCS is a combination of one or more combustion/gas turbine electric generating units and one steam turbine electric generating unit. Gas turbines, which are similar to jet engines, are typically fueled with natural gas, but may also be fueled with clean oil, often during times of peak energy demand.

In CCSs, gas turbines are connected to generators that produce electricity. Hot exhaust gases (i.e., waste heat) from the gas turbines are transported to heat recovery steam generators (HRSGs) to generate steam to drive an additional turbine. The steam turbine is connected to a generator (which may be a different generator or the same generator that is connected to a gas turbine) that produces additional electricity. Thus, CCSs use steam turbine technology to increase the efficiency of the gas turbines. Figure 3-5 illustrates the CCS process.

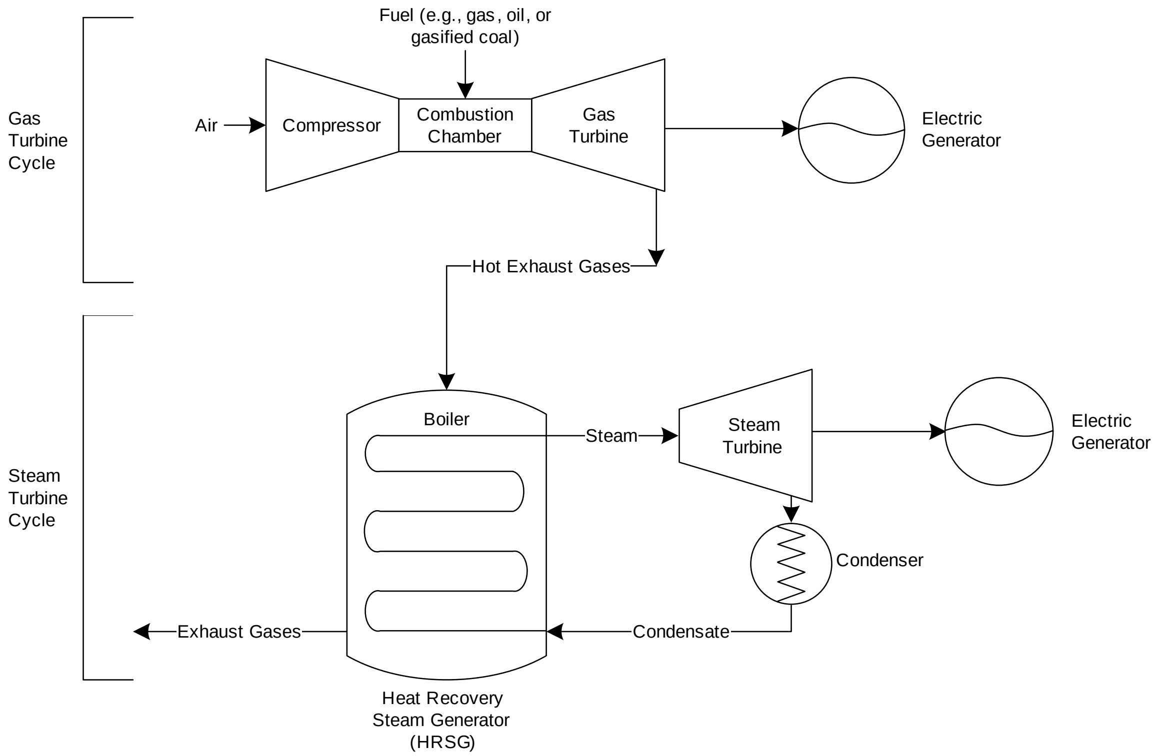


Figure 3-5. Combined Cycle Process Flow Diagram

Some CCSs use a technology termed "gasification" to create gaseous fuel from solid or liquid fossil fuels. Gasification creates synthesis gas (syngas), which consists mainly of carbon monoxide and hydrogen gas from fossil fuels, such as vacuum residue, heavy oil, petroleum coke, and coal, by a partial oxidation process [Chiyoda, 2006]. CCSs that use this gasification technology are known as integrated gasification combined cycle (IGCC) systems. In IGCC systems, syngas is purified and combusted in a gas turbine generator to produce electricity. Heat from the exhaust gas is recovered and used to generate steam to produce additional electricity. IGCC facilities are thermodynamically more efficient than traditional steam electric facilities.

Currently, there are 20 to 25 gasification plants in operation around the world that generate electricity and approximately 35 additional gasification facilities in various stages of development, design, and construction. The total installed global capacity amounts to 24,000 MW of electricity with an annual growth rate of about 10 percent [U.S. DOE, 2006c]. IGCC is less common in the United States than in other countries[10]; however, several U.S. facilities are investigating IGCC and others have definite plans to build IGCC systems in the future.

The operation of steam electric units within CCSs is virtually identical to stand-alone steam electric units, with the exception of the boiler. In a CCS, the gas turbines and HRSGs functionally take the place of the boiler of a stand-alone steam electric unit. The other

[10] There are currently two commercial-scale, coal-based IGCC facilities in the United States: the 262-MW Wabash River IGCC Repowering Project in Indiana and the 250-MW Tampa Electric Polk Power Station IGCC Project in Florida [U.S. EPA, 2006e].

two major components of steam electric units within CCSs, the steam turbine/electric generator and steam condenser, are virtually identical to those of stand-alone steam electric units. Thus, the wastewaters and pollutants generated from the steam/condensation side of the CCS process are the same as those from the stand-alone steam electric process. These wastewaters include cooling water and steam condensate water treatment wastes.

Wastewaters associated with the CCS steam water system (e.g., HRSG, steam turbine, and condenser) are currently regulated by the Steam Electric ELGs [U.S. EPA, 1989]. EPA researched available information about CCS combustion/gas generating unit wastewaters to determine whether the wastewaters generated by the gas generating unit of a CCS are similar to the steam electric wastewaters already regulated by the Steam Electric ELGs.

According to comments received in 1996 from EPA regional and state authorities, gas turbines may generate wastewaters from emissions control, equipment cooling, and equipment turbine cleaning [U.S. EPA, 1996]. Gas turbines require clean-burning fuels, and thus, CCS gas turbines do not discharge ash wastewaters. Although the amount of wastewaters from the gas turbines is relatively low, they may contain similar pollutants and concentrations as the regulated steam electric wastewaters. Wastewaters from IGCC facilities are also likely to contain similar pollutants originating from the gasification process, upstream of the gas turbine. Additionally, IGCC facilities may discharge wastewater associated with gasifier slag (coal ash) [U.S. EPA, 2006e].

EPA has found no additional data to date that provide information about the specific pollutants or concentrations likely to be found in CCS gas turbine wastewaters. The wastewaters generated by gas turbines may warrant further consideration and study.

3.3 Demographics of the Electric Generating Industry

As previously explained in Section 2.0, EPA analyzed the available demographic information for the year 2002 collected by the U.S. DOE and other government sources (e.g., TRI and PCS) to characterize the industry. This section presents available demographic data and other information for the electric generating industry.

EPA obtained the demographic data presented in this section of the report primarily from the *PCSLoads2002 v.4* database [U.S. EPA, 2006a], the 2002 EIA database (Form EIA-860) [U.S. DOE, 2002a], as well as the 2002 Economic Census [USCB, 2002]. Electric generating facilities that report to the PCS are identified within SIC codes 4911, 4931, and 4939. Electric generating facilities are identified in the EIA data as typically reporting under NAICS code 22 – Utilities[11]. The 2002 Economic Census data include more specific industry sector information at the six-digit NAICS code level.

[11] NAICS code 22 – *Utilities* is defined as establishments providing the following utility services: electric power, natural gas, steam supply, water supply, and sewage removal. Excluded from this sector are establishments primarily engaged in waste management services [USCB, 2002].

3.3.1 Overview of the Electric Generating Industry

According to the Economic Census, there were 2,138 electric generating facilities in the United States in 2002, 61 percent of which are characterized primarily as using fossil or nuclear fuel [USCB, 2002]. Table 3-1 presents the distribution of facilities among each of the electric generating NAICS codes.

Table 3-1. Distribution of U.S. Electric Generating Facilities by NAICS Code

NAICS Code - Description	Facilities
221111 – Hydroelectric Power Generation	416
221112 – Fossil Fuel Electric Power Generation	1,233
221113 – Nuclear Electric Power Generation	78
221119 – Other Electric Power Generation	411
22111 – Electric Power Generation (Total)	**2,138**

Source: USCB, 2002.

EPA extracted TRI data reported in 2002 for all facilities within SIC codes 4911, 4931, and 4939. Of the 692 electric generating facilities that reported to TRI, only 376 (54 percent) reported manufacturing, processing, or using listed toxic chemicals at or above their reporting thresholds, which resulted in wastewater discharges of that chemical [U.S. EPA, 2006b]. Table 3-2 shows the distribution of the TRI facilities by SIC code.

Table 3-2. Distribution of TRI Electric Generating Facilities by SIC Code

SIC Code	Total Facilities Reporting	Facilities Reporting No Discharge of TRI Chemicals to Water	Facilities Reporting Direct Discharge of TRI Chemicals	Facilities Reporting Indirect Discharge of TRI Chemicals	Facilities Reporting Both Direct and Indirect Discharge of TRI Chemicals
4911	639	289	320	12	18
4931	45	20	19	3	3
4939	8	7	1	0	0
Total	**692**	**316**	**340**	**15**	**21**

Source: U.S. EPA, 2006b.

EPA also extracted all PCS data reported by major and minor sources within SIC codes 4911, 4931, and 4939 for the study. In the PCS database, 885 electric generating facilities reported wastewater data in 2002. Of the 885 facilities, 556 (63 percent) are major dischargers and 329 are minor dischargers. Table 3-3 shows the distribution of the PCS facilities by SIC code.

Table 3-3. Distribution of PCS Electric Generating Facilities by SIC Code

SIC Code - Description	Major Dischargers	Minor Dischargers	Total
4911 – Electric Services	547	266	813
4931 – Electric and Other Services Combined	9	42	51
4939 – Combination Utilities, NEC	0	21	21
Total	**556**	**329**	**885**

Source: U.S. EPA, 2006a.
NEC – Not elsewhere classified.

The data reported to PCS and TRI were used in this study to characterize the wastewater generated by the electricity generating industry, and are discussed in greater detail in Chapter 5.

Combination utilities (SIC code 4939) by definition include facilities other than electricity generating facilities; therefore, only a fraction of the few facilities reporting to PCS and TRI as combination utilities are believed to be electricity generating facilities. As such, the analyses of the PCS and TRI data presented in this report do not include combination utilities. EPA investigated this industry classification during the study as a potential new subcategory for the Steam Electric ELGs. Chapter 8 of this report discusses the Combination Utilities industry in further detail.

Finally, EPA examined the data on electricity generating facility operations that were reported to the EIA in 2002. Form EIA-860 contains records for 16,413 electricity generators having at least one MW of capacity operated at 5,137 facilities for calendar year 2002 [U.S. DOE, 2002a]. These facilities include both electricity generating facilities and industrial non-utilities.

Subsection 3.3.2 presents additional demographic data obtained through the 2002 EIA database specific to the regulated steam electric industry.

3.3.2 Regulated Steam Electric Generating Industry

Because Form EIA-860 contained the most detailed information on facility type, energy source, and capacity, EPA used these data from EIA to develop a demographic profile of the electric generating industry currently regulated by the Steam Electric ELGs. As mentioned in the previous subsection, these records include data from all facilities that produce electricity, not specifically steam electric facilities. EPA defined the subset of EIA data for the regulated steam electric industry based on the NAICS code, prime mover, and energy source reported.

All electric generating facilities (i.e., utilities, non-industrial non-utilities, and industrial non-utilities) report information about each of their generating units to the EIA in Form EIA-860, and each facility identifies a “primary purpose” code for its operations that is equivalent to their NAICS code. Utilities and non-industrial non-utilities report under the general NAICS code 22, while industrial non-utilities report under the particular NAICS code for their primary industry. Because both utilities and non-industrial non-utilities are regulated by the

Steam Electric ELGs, their EIA data are combined for the purposes of presenting the available EIA data for the regulated steam electric industry.

EPA identified the subset of electric generating facilities in the EIA database that are *steam electric* as those operating at least one prime mover that utilizes steam. The following generating unit or prime mover types are included in the demographic data for the steam electric industry presented in this report:

- Steam turbine;
- CCS - steam turbine portion; and
- CCS - single shaft (i.e., the combustion/gas turbine and steam turbine are used together to drive a single generator).

For the purposes of this report, EPA combined the data reported for the two types of CCSs in EIA.

Finally, EPA identified the subset of steam electric facilities that are currently regulated by the Steam Electric ELGs that report using a fossil or nuclear fuel as the primary energy source for the steam electric generating unit. The following fossil or nuclear fuel types are included in the demographic data for the regulated steam electric industry presented in this section of the report (abbreviations used by EIA are presented in parentheses):

- Anthracite coal, bituminous coal;
- Lignite coal;
- Subbituminous coal;
- Petroleum coke;
- Waste/other coal;
- Distillate fuel oil;
- Residual fuel oil;
- Jet fuel;
- Kerosene;
- Oil-other and waste oil (e.g., crude oil, liquid by-products, oil waste, propane (liquid), re-refined motor oil, sludge oil, tar oil);
- Natural gas; and
- Nuclear (e.g., uranium, plutonium, thorium).

Using the criteria for the prime mover type and energy source described above for all facilities (utilities and non-industrial non-utilities) reporting a primary purpose/NAICS code of 22, EPA estimates that 1,157 regulated steam electric facilities reported to the EIA in 2002. These facilities are estimated to operate 2,597 stand-alone steam generators or combined cycle systems, which have a total steam turbine capacity of 621,799 MW[12] [U.S. DOE, 2002a].

Table 3-4 shows the distribution of the types of steam electric prime movers used by facilities subject to the Steam Electric ELGs. The table presents the numbers of facilities, generating units, and capacities for each type of steam electric prime mover. Based on the 2002 EIA data, virtually all (93 percent) of the steam-generated electricity produced by the regulated industry is done so through stand-alone steam turbines, which are also the most prevalent type of steam electric prime mover used.

Table 3-4. Distribution of Prime Mover Types Within the Regulated Steam Electric Industry

Steam Electric Prime Mover	Number of Facilities[a]	Number of Generating Units	Total Steam Turbine Capacity (MW)
Stand-Alone Steam Turbine	891 (77%)	2,210 (85%)	578,282 (93%)
CCS Steam Turbine	303 (26%)	387 (15%)	43,517 (7%)
Total	**1,157 (100%)**	**2,597 (100%)**	**621,799 (100%)**

Source: U.S. DOE, 2002a.
[a]Because a single facility may operate multiple generating units of various types, the number of facilities by prime mover type is not additive. There are 1,157 facilities in the industry that operate at least one steam electric generating unit powered by either fossil or nuclear fuel.

In the 2002 EIA database, an estimated 303 regulated steam electric facilities reported operating at least one fossil-fueled CCS. The total CCS capacity is estimated to be 112,451 MW, 39 percent of which is generated via steam-turned generators (i.e., both the steam portion of multishaft CCSs and single-shaft CCSs). Approximately 43,500 MW of capacity is produced via steam-driven CCS generators, which accounts for seven percent of the electricity produced by the regulated steam electric industry [U.S. DOE, 2002a].

Table 3-5 shows the distribution of fossil and nuclear fuels used in the regulated steam electric industry. Table 3-6 shows the distribution of fossil and nuclear fuels to power each type of steam electric prime mover. The 2002 EIA data demonstrate that more than half of the steam-generated electricity currently produced by the regulated steam electric industry is primarily fueled by coal used in stand-alone steam turbines.

[12] The EIA database contains 1,152 facilities reporting a total of 2,592 steam electric units, and an additional 5 facilities reporting at least one CCS combustion/gas turbine only. EPA assumes these additional five facilities are each operating a single steam turbine as part of their CCS, even though it was not reported to EIA. The total steam turbine capacity does not include the unknown capacities for the five CCS steam electric turbines that are assumed in the total number of facilities and generating units.

Table 3-5. Distribution of Fuel Types Within the Regulated Steam Electric Industry

Fossil or Nuclear Fuel[a]	Number of Facilities[b]	Number of Generating Units	Total Steam Turbine Capacity (MW)[c]
Coal:	513 (44%)	1,255 (48%)	332,923 (54%)
Anthracite Coal, Bituminous Coal	360	935	229,465
Subbituminous Coal	126	273	87,364
Lignite Coal	18	30	14,753
Waste/Other Coal	17	17	1,341
Petroleum Coke	12 (1.0%)	14 (0.5%)	824 (0.1%)
Oil:	90 (7.8%)	190 (7.3%)	34,532 (5.6%)
Residual Fuel Oil	74	163	32,443
Distillate Fuel Oil	17	27	2,089
Natural Gas	548 (47%)	1,029 (40%)	148,586 (24%)
Nuclear	66 (5.7%)	104 (4.0%)	104,933 (17%)
Total	**1,157 (100%)**	**2,597 (100%)**	**621,799 (100%)**

Source: U.S. DOE, 2002a.
[a]No steam electric generating units were reported to use jet fuel, kerosene, or waste/other oil in the 2002 EIA database.
[b]Because a single facility may operate multiple generating units utilizing differing fuel types, the number of facilities by fuel type is not additive. There are 1,157 facilities in the industry that operate at least one steam electric generating unit powered by either fossil or nuclear fuel.
[c]The total steam electric capacity shown does not equal the sum of the steam electric capacities for each fuel type due to rounding errors.

Table 3-6. Distribution of Fuel Types Used by Steam Electric Generating Units

Fossil or Nuclear Fuel[a]	Number of Generating Units		
	Stand-Alone Steam Turbines	CCS Steam Turbines[b]	Total
Coal:	1,254 (57%)	1 (0.26%)	1,255 (48%)
Anthracite Coal, Bituminous Coal	934	1	935
Subbituminous Coal	273	0	273
Lignite Coal	30	0	30
Waste/Other Coal	17	0	17
Petroleum Coke	14 (0.6%)	0 (0%)	14 (0.5%)
Oil:	180 (8.1%)	10 (2.5%)	190 (7.3%)
Residual Fuel Oil	157	6	163
Distillate Fuel Oil	23	4	27
Natural Gas	658 (30%)	371 (96%)	1,029 (40%)
Nuclear	104 (4.7%)	0 (0%)	104 (4.0%)
Total	**2,210 (100%)**	**387[b] (100%)**	**2,597 (100%)**

Source: U.S. DOE, 2002a.
[a]No steam electric generating units were reported to use jet fuel, kerosene, or waste/other oil in the 2002 EIA database.
[b]The database contains a total of 382 CCS steam turbines, with an additional five facilities reporting at least one CCS gas turbine only. EPA assumes there is an additional five CCS steam turbines in operation, even though they were not reported to EIA. The numbers of CCS steam turbines shown for each fuel type do not account for these five units that are assumed in the total.

The second most prevalent fuel used by the regulated steam electric industry is natural gas, which is used to produce nearly 25 percent of the steam-generated electricity from this segment of the industry. According to the 2002 EIA data, 30 percent of stand-alone steam turbines are powered by natural gas. Nearly all CCSs (96 percent) are fueled by natural gas; however, a small number were also reported to be fueled by oil. The facility that reported coal for its CCS is PSI Energy's Wabash River Plant, which is one of two known IGCC units operating in the United States. Therefore, it should be noted that this "coal-fired" CCS is actually powered by syngas provided through coal gasification [U.S. DOE, 2002a]. Section 3.2.2 contains additional information about IGCC systems.

Table 3-7 presents the steam electric capacity, as well as the number of regulated steam electric facilities and generating units, distributed by *overall plant capacity*[13]. According to these 2002 EIA data, the majority of steam electric facilities and generating units, as well as the majority of the electricity provided by the regulated steam electric industry, is from the largest capacity facilities (>500 MW).

Table 3-7. Distribution of Regulated Steam Electric Capacity, Facilities, and Generating Units by Size

Overall Plant Capacity[a]	0-50 MW	50-100 MW	100-200 MW	200-300 MW	300-400 MW	400-500 MW	>500 MW	Total
Total Steam Electric Capacity (MW)	2,966	6,621	16,592	17,106	17,365	22,812	538,337	621,799[b]
Percentage of Capacity	0.48%	1.1%	2.7%	2.8%	2.8%	3.7%	87%	100%
Number of Facilities	133	128	159	92	66	63	511	1,157[c]
Percentage of Facilities	11%	11%	14%	8.0%	5.7%	5.4%	44%	100%
Number of Steam Electric Generating Units	222	225	297	183	146	150	1,369	2,597[c]
Percentage of Steam Electric Generating Units	8.5%	8.7%	11%	7.0%	5.6%	5.8%	53%	100%

Source: U.S. DOE, 2002a.
[a]Plant capacity includes electricity produced by both steam and non-steam generating units, as well as through the use of non-fossil/non-nuclear energy sources.
[b]The total steam electric capacity shown does not equal the sum of the steam electric capacities for each size category due to rounding errors.
[c]It is estimated that there are a total of 1,157 facilities in the 2002 EIA database that operate 2,597 steam electric generating units. The database contained 1,152 facilities reporting a total of 2,592 steam electric units, and an additional five facilities reporting at least one CCS gas turbine only. EPA assumes these additional five facilities are each operating a single steam turbine as part of their CCS, even though it was not reported to EIA. The number of facilities and generating units shown for plant capacity range do not account for these five CCS steam electric turbines that are assumed in the totals.

[13] The overall plant capacity includes all electric power generated by the facility, including electricity produced by non-steam generators and through the use of non-fossil/non-nuclear energy sources.

In general, electricity produced by coal-fired steam electric generating units increased rapidly in the 1970s, but has since leveled off. Increases in the regulated industry's capacity in recent years coincide with increases in natural gas-fired electricity generating units, according to the 2002 EIA database [U.S. EPA, 2005b].

Nearly 83 percent of the regulated steam electric facilities that reported operation of a CCS indicated the system was constructed or started up as early as 1982, the year the Steam Electric ELGs were last revised [U.S. DOE, 2002a]. According to the 2002 EIA data and as shown in Figure 3-6, an increasing number of regulated steam electric facilities have installed (i.e., started up) a new CCS since roughly 1985[14].

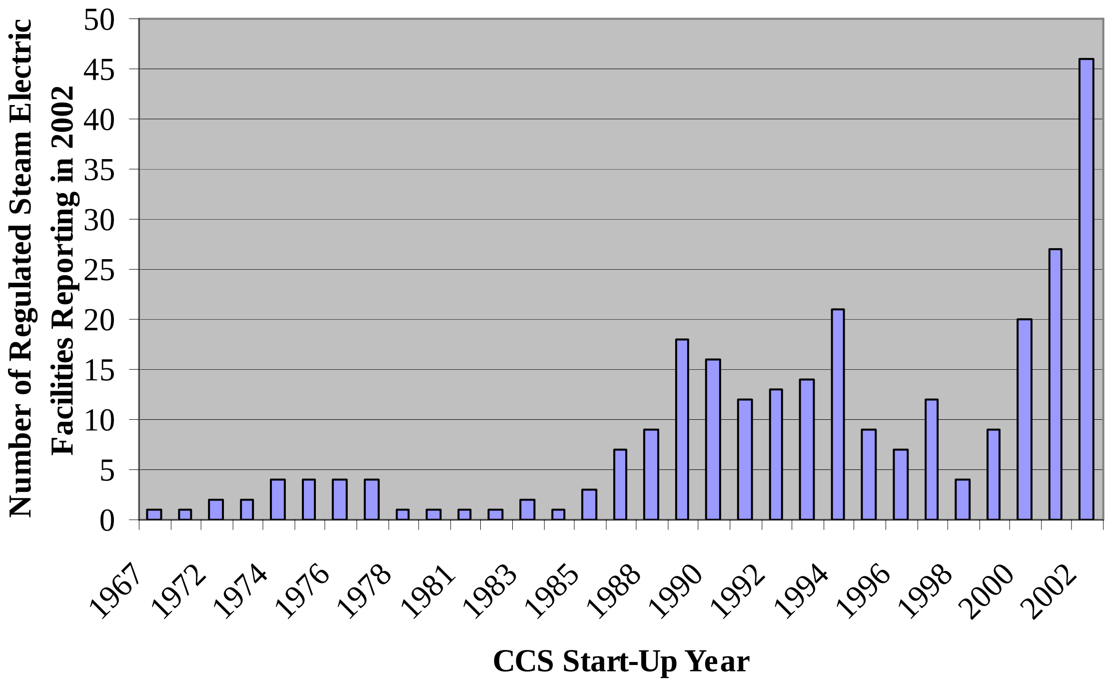


Figure 3-6. Trend Toward Increased Operation of CCSs Within the Regulated Steam Electric Industry
Source: U.S. DOE, 2002a

[14] Note that the number of facilities shown for each year is not cumulative. They represent the number of facilities that reported operation of a CCS that was initially started up within that year. In addition, these data reflect CCSs that were in operation in 2002. They do not include CCSs that may have existed in previous years, but were shut down or otherwise not in operation as of 2002.

4.0 SELECTED ENVIRONMENTAL REGULATIONS AFFECTING THE STEAM ELECTRIC INDUSTRY

This chapter presents a brief overview of selected regulations affecting steam electric facilities.

4.1 Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (40 CFR 423)

The Federal Water Pollution Control Act of 1972 established a structure for regulating discharges of pollutants to surface waters of the United States. As part of the implementation of the Act, EPA issued ELGs for industrial dischargers. EPA issued the first ELGs for the Steam Electric Power Generating Point Source Category (i.e., the Steam Electric ELGs) in 1974 with subsequent revisions in 1977 and 1982. The Steam Electric ELGs are codified at 40 CFR 423 and include limitations for the following waste streams:

- Once-through cooling water;
- Cooling tower blowdown;
- Fly ash transport water;
- Bottom ash transport water;
- Metal cleaning wastes;
- Coal pile runoff; and
- Low-volume waste sources, including but not limited to wastewaters from wet scrubber air pollution control systems, ion exchange water treatment systems, water treatment evaporator blowdown, laboratory and sampling streams, boiler blowdown, floor drains, cooling tower basin cleaning wastes, and recirculating house service water systems (sanitary and air conditioning wastes are not included) [40 CFR 323.11(b)].

The 1982 promulgation reserved the following four types of waste streams for future rulemaking:

- Non-chemical metal cleaning wastes;
- FGD wastewater (Note: this wastewater source is covered by the current ELGs among *low-volume waste sources*);
- Runoff from materials storage and construction areas (other than coal storage); and
- Thermal discharges.

The current ELGs are summarized in Table 4-1 and are applicable to:

"…discharges resulting from the operation of a generating unit by an establishment primarily engaged in the generation of electricity for distribution and sale which results primarily from a process utilizing fossil-type fuel (coal, oil, or gas) or nuclear fuel in conjunction with a thermal cycle employing the steam water system as the thermodynamic medium." (§423.10)

Currently, 40 CFR Part 423 does not apply to facilities that primarily use a renewable fuel source (e.g., wood waste, municipal solid waste) to power the steam electric generators or fossil- or nuclear-powered steam electric generating facilities that do not sell a majority of the electricity produced.

4.2 Clean Water Act Section 316(b) - Cooling Water Intake Structures

Section 316(b) of the CWA requires EPA to ensure that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available to minimize adverse environmental impacts. Such impacts include death or injury to aquatic organisms by impingement (being pinned against screens or other parts of a cooling water intake structure) or entrainment (being drawn into cooling water systems and subjected to thermal, physical, or chemical stresses). The CWA section 316(b) regulations were developed in three phases:

- Phase I, promulgated on December 18, 2001 [66 FR 65256], covers new facilities that use cooling water intake structures to withdraw water from waters of the United States and that have or require a NPDES permit. New facilities subject to the Phase I regulations include those that have a design intake flow of greater than 2 MGD and that use at least 25 percent of the water withdrawn for cooling purposes.

- Phase II, promulgated on July 9, 2004 [69 FR 41576], establishes performance standards and other requirements for cooling water intake structures at large existing electric generating plants that use at least 50 MGD of water from waters of the United States.

- Phase III, promulgated on June 16, 2006 [71 FR 35006], establishes requirements for intake structures at new offshore and coastal oil and gas extraction facilities that have a design intake flow of greater than 2 MGD and that use at least 25 percent of the water withdrawn for cooling purposes.

Manufacturing facilities, existing electric generating facilities with a design intake flow of less than 50 MGD, and existing offshore oil and gas extraction facilities are not subject to section 316(b) national categorical requirements. CWA section 316(b) requirements for existing facilities not covered under the Phase II rule are implemented through NPDES permits on a case-by-case, best professional judgment (BPJ) basis [U.S. EPA, 2006f].

Table 4-1. Current Effluent Guidelines and Standards for the Steam Electric Power Generating Point Source Category

Waste Stream	BPT[a]	BAT[a]	NSPS[a]	PSES and PSNS[a]
All Waste Streams	pH: 6-9[b] PCBs: Zero discharge	PCBs: Zero discharge	pH: 6-9[b] PCBs: Zero discharge	PCBs: Zero discharge
Low-Volume Wastes	TSS: 100/30 O&G: 20/15	No limitation[c]	TSS: 100/30 O&G: 20/15	No limitation[d]
Fly Ash Transport	TSS: 100/30 O&G: 20/15	No limitation[c]	Zero discharge	Zero discharge (PSNS only) No limitation for PSES[d]
Bottom Ash Transport	TSS: 100/30 O&G: 20/15	No limitation[c]	TSS: 100/30 O&G: 20/15	No limitation[d]
Metal Cleaning Wastes	TSS: 100/30 O&G: 20/15 Cu: 1.0/1.0 Fe: 1.0/1.0	See *Chemical Metal Cleaning Wastes* below	See *Chemical Metal Cleaning Wastes* below	See *Chemical Metal Cleaning Wastes* below
Chemical	See *Metal Cleaning Wastes* above	Cu: 1.0/1.0 Fe: 1.0/1.0 [3]	TSS: 100/30 O&G: 20/15 Cu: 1.0/1.0 Fe: 1.0/1.0	Cu: 1.0 [4]
Non-chemical	See *Metal Cleaning Wastes* above	Reserved	Reserved	Reserved
Once-Through Cooling	FAC: 0.5/0.2	TRC: 0.20 max or BPT if <25 MW	TRC: 0.20 max or BPT if <25 MW	No limitation[e]
Cooling Tower Blowdown	FAC: 0.5/0.2	FAC: 0.5/0.2 126P: Zero discharge, except: Cr: 0.2/0.2 Zn: 1.0/1.0	FAC: 0.5/0.2 126P: Zero discharge, except: Cr: 0.2/0.2 Zn: 1.0/1.0	126P: Zero discharge, except: Cr: 0.2/0.2 Zn: 1.0/1.0
Coal Pile Runoff	TSS*: 50	No limitation[c]	TSS*: 50	No limitation[d]

Sources: 40 CFR 423; 47 FR 52290 – 52309.
Refer to the Acronyms List, provided on page vii of this report. Additional notes are provided below.
FAC: 0.5/0.2 - 0.5 mg/L instantaneous maximum, 0.2 mg/L average during chlorine release period. Discharge is limited to 2 hrs/day/unit. Simultaneous discharge of chlorine from multiple units is prohibited. Limitations are applicable at the discharge from an individual unit prior to combination with the discharge from another unit.
TRC: 0.20 max - 0.20 mg/L instantaneous maximum. TRC = FAC + CRC. TRC discharge is limited to 2 hrs/day/unit. TRC is applicable to plants ≥ 25 MW, and FAC is applicable to plants < 25 MW. The TRC limitation is applicable at the discharge point to surface waters of the United States and may be subsequent to combination with the discharge from another unit.
126P: zero discharge - 126 priority pollutants from added maintenance chemicals (refer to App. A to 40 CFR 423). At the permitting authority's discretion, compliance with the zero-discharge limitations for the 126 priority pollutants may be determined by engineering calculations, which demonstrate that the regulated pollutants are not detectable in the final discharge by the analytical methods in 40 CFR part 136.
TSS*: 50 - 50 mg/L instantaneous maximum on coal pile runoff streams. No limitation on TSS for coal pile runoff flows ≥ 10-year, 24-hour rainfall event.
[a]The limitations for TSS, O&G, Cu, Fe, Cr, and Zn are presented as daily maximum (mg/L)/30-day average (mg/L). For all ELGs, where two or more waste streams are combined, the total pollutant discharge quantity may not exceed the sum of allowable pollutant quantities for each individual waste stream. BPT, BAT, and NSPS allow either mass- or concentration-based limitations.
[b]The pH limitation is not applicable to once-through cooling water.

Table 4-1 (Continued)

[c]BAT limitations for the conventional pollutants, TSS and O&G, were withdrawn from the CFR (in the 1982 promulgation) because these pollutants are covered under BCT. In the 1982 promulgation, EPA reserved BCT for the steam electric industry. Refer to 47 FR 52293.
[d]In the 1982 promulgation, EPA withdrew the 1977 PSES requirement for O&G for all waste streams (47 FR 52293).
[e]There are no pretreatment standards (except the PCB prohibition) because no known facilities discharge once-through cooling water to POTWs [47 FR 52294].

4.3 Clean Air Act

Electric utility generating units that fire fossil fuels are subject to several regulations under the Clean Air Act (CAA). These regulations include CAIR, CAMR, Clean Air Visibility Rule (CAVR), Acid Rain Program, NSPS, and National Emissions Standards for Hazardous Air Pollutants (NESHAP). Each of these regulations is summarized briefly below:

- CAIR. Published in 2005, CAIR will regulate SO_2 and NO_x emissions to help states achieve the National Ambient Air Quality Standards (NAAQS) for ozone and fine particulate matter. The rule permanently caps emissions (tons per year) across 28 eastern states and the District of Columbia. The Phase I Caps for NO_x and SO_2 will take effect in 2009 and 2010, respectively. The lower Phase II caps for both SO_2 and NO_x take effect in 2015. States must meet the caps by establishing emission limitations or participating in a regional cap and trade program. EPA anticipates that states will achieve these standards by primarily focusing on reducing the emissions from the power generating industry.

- CAMR. Published in 2005, this rule established a national cap and trade program for mercury emissions from power plants. Plants will be able to meet the first phase cap in 2010 using the same technologies currently used to control SO_2 and NO_x in complying with CAIR. The second phase cap in 2018 is expected to require facilities to use mercury-specific control technologies to comply.

- CAVR. On June 15, 2005, EPA finalized amendments to the July 1999 regional haze rule. These amendments apply to the provisions of the regional haze rule that require emission controls known as “best available retrofit technology” (BART) for industrial facilities emitting air pollutants that reduce visibility by causing or contributing to regional haze. The pollutants that reduce visibility include fine particulate matter and compounds that contribute to its formation, including SO_2 and others. The amendments include final guidelines, known as BART guidelines, for states to use in determining which facilities must install controls and the type of controls the facilities must use. States that adopt the CAIR cap and trade program for SO_2 and NO_x are allowed to apply CAIR controls as a substitute for controls required under BART because the analysis concluded that CAIR controls are “better than BART” for electric generating units in the states subject to CAIR.

- Acid Rain. The acid rain program established a national cap and trade program for SO_2 emissions from fossil fuel-fired power plants. Phase I began in 1995 and affected 445 mostly coal-fired electric utility plants located in 21 eastern and midwestern states. Phase II, which began in the year 2000, lowered the emission caps on the Phase I plants and also capped emissions on all units nationwide with more than 25 MW of capacity and fired by coal, oil, or gas. The program also established emission limitations for NO_x.

- NSPS. These regulations established limitations on SO_2, particulate matter, NO_x, and mercury emitted from new, modified, or reconstructed electric utility boilers. EPA proposed amendments to the SO_2, particulate matter and NO_x NSPS in February 2005 [70 FR 9706] and adopted the final amendments in February 2006 [71 FR 9866]. EPA finalized the mercury NSPS in May 2005 [70 FR 28606] and issued the final notice of reconsideration (which amended the NSPS) on June 9, 2006 [71 FR 33388].

  The SO_2 standard for units burning high-sulfur coals requires approximately a 95-percent reduction of emissions, which requires FGD. Units burning low-sulfur coals can achieve the standard with approximately 80 percent reduction, which can be met using a spray dryer. Spray dryers do not generate a wastewater stream. The NO_x emission limitations require the use of SCR or selective non-catalytic reduction (SNCR). The particulate matter NSPS can be met using an electrostatic precipitator (ESP) or baghouse.

  EPA established separate NSPS limits for mercury for four ranks of coal (bituminous, subbituminous, lignite, and coal refuse) and one process (IGCC). Facilities can meet the mercury NSPS emission limitations using the same technologies used to meet the SO_2 and NO_x NSPS emission limitations.

- NESHAP. This regulation regulates hazardous air pollutant emissions from the following: industrial, commercial, and institutional boilers and process heaters [70 FR 76918; December 28, 2005], as well as combustion turbines and reciprocating internal combustion engines (RICEs).

4.4 Resource Conservation and Recovery Act

The management of CCRs (e.g., fly ash, bottom ash, boiler ash, boiler slag, and flue gas emission control wastes) is subject to regulations under the Resource Conservation and Recovery Act (RCRA). In 1993, EPA completed a hazard study of CCR waste disposal and recommended that CCRs be regulated at the state level as RCRA Subtitle D wastes. The 1993 action also affirmed that CCRs should be excluded from RCRA Subtitle C hazardous waste regulations [58 FR 42466; August 9, 1993]. Again in 2000, EPA completed a follow-up study of low-volume, comanaged wastes[15] and issued a regulatory determination that these wastes be exempted from Subtitle C regulations [65 FR 32214; May 22, 2000]. No federal regulations currently exist for solid wastes from steam electric facilities; instead, they are managed by state solid waste programs or specific programs for fossil fuel combustion wastes [U.S. EPA, 2006c].

At that time, however, concerns were raised over the disposal of CCRs in surface impoundments and landfills as well as the use of CCR as backfill in mining operations. EPA's OSW is currently developing federal regulations under RCRA Subtitle D to address issues

[15] Comanaged wastes are low-volume wastes that are comanaged with the high-volume CCRs [U.S. EPA, 2006c].

related to disposal to surface impoundments and landfills, which include the potential for pollutants to be transferred from the solid wastes to ground or surface waters. For coal mining operations, OSW is working with the U.S. Department of Interior's Office of Surface Mining to address these issues under the Subsurface Mining Control and Reclamation Act (SMCRA).

In addition, increased use of air pollution control technologies to meet new emission requirements (described previously in this chapter) may impact the pollutants found in CCRs. OSW is working with ORD and EPA's National Risk Management Research Laboratory (NRMRL) to evaluate the impact of air pollution control on the characteristics of CCRs, including understanding the potential environmental impacts from the disposal and beneficial use of CCRs. The outcome of this research will help to identify potential management practices of concern where cross-media transfers may occur. In addition, it will provide methodology and data for quantifying potential benefits and environmental tradeoffs from CCR utilization [U.S. EPA, 2006c].

With respect to the use of CCRs as backfill in mines, EPA commissioned a study of the risks by the NRC. The NRC has issued a report presenting the results of this study [NRC, 2006] (additional information about this report is presented in Section 2.4.4).

5.0 STEAM ELECTRIC INDUSTRY WASTEWATER CHARACTERIZATION

This chapter analyzes available data to characterize the waste streams discharged from steam electric facilities and the technologies and practices used in the industry to control the discharge of wastewater pollutants. Table 5-1 presents an overview of the types of pollutants associated with the various waste streams, based on data previously collected by EPA during the 1974 and 1982 rulemaking efforts and the 1996 Preliminary Data Summary, data provided by UWAG and EPRI, and currently available pollutant data from TRI, PCS, and literature. Section 3.2.1 of this report describes waste streams from this industry.

Table 5-1. Waste Streams from the Steam Electric Industry and Pollutants Typically Associated with the Discharge

Process Waste Stream	Pollutants
Cooling Water: Once-Through or Cooling Tower Blowdown	Chlorine, iron, copper, nickel, aluminum, boron, chlorinated organic compounds, suspended solids, brominated compounds, non-oxidizing biocides
Ash Handling: Bottom or Fly Ash	TDS, TSS, sulfate, calcium, chloride, magnesium, nitrate, aluminum, antimony, arsenic, boron, cadmium, chromium, copper, cyanide, iron, lead, mercury, nickel, selenium, silver, titanium, thallium, vanadium, zinc, various metal oxides, carbon residuals
Coal Pile Runoff	Acidity, COD, calcium, silica, chloride, sulfate, TDS, TSS, aluminum, antimony, arsenic, boron, beryllium, cadmium, chromium, copper, iron, lead, magnesium, manganese, mercury, nickel, selenium, silver, thallium, vanadium, zinc
Water Treatment	**Clarification:** aluminum sulfate, sodium aluminate, ferrous sulfate, ferrous chloride, calcium carbonate
	Filtration: suspended solids
	Ion Exchange: calcium and magnesium salts, iron, copper, zinc, aluminum, manganese, potassium, soluble sodium, chlorides, sulfates, organics, sulfuric acid, sodium hydroxide
	Evaporation: salts (type depends on intake water characteristics)
	Softening: calcium carbonate, magnesium hydroxide, sodium salts
Boiler Blowdown	Chlorides, sulfates, metals, precipitated solids containing calcium and magnesium salts, soluble and insoluble corrosion products, chemical additives
Flue Gas Desulfurization Waste from Wet Scrubbers	A slurry of ash, unreacted lime, calcium sulfate/gypsum, calcium sulfite, TDS, TSS, and remaining trace constituents of coal (including, but not limited to aluminum, arsenic, boron, copper, iron, mercury, nickel, selenium, and zinc)
Maintenance Cleaning	Oil, grease, phosphates, nitrites, suspended solids, dissolved solids, iron, nickel, chromium, vanadium, zinc, magnesium salts, polynuclear hydrocarbons, acidity, alkalinity, oil
Other Low-Volume Waste Streams	Suspended solids, dissolved solids, oil and grease, phosphates, surfactants, acidity, methylene chloride, phthalates, BOD_5, COD, fecal coliform, and nitrates

Note: this table is intended to present the types of pollutants that are commonly expected to be found in various steam electric process waste streams, as supported by the sources reviewed during this study. It is presented here for informational purposes and does not necessarily provide a complete characterization of the waste streams.
Refer to the Acronyms List, provided on page vii of this report.

5.1 Identification of the PCS and TRI Steam Electric Data

The primary data sources used in these analyses are described in Chapter 2 of this report. This section presents additional information on the criteria used in identifying the subset of data from the 2002 PCS and TRI databases that represent the regulated steam electric industry.

As described in Section 3.1, the regulated steam electric industry is defined by the current ELGs for the Steam Electric Power Generating Point Source Category at 40 CFR 423.10 as facilities "primarily engaged in the generation of electricity for distribution and sale which results primarily from a process utilizing fossil-type fuel (coal, oil, or gas) or nuclear fuel in conjunction with a thermal cycle employing the steam/water system as the thermodynamic medium."

In the PCS and TRI databases, facilities are categorized by SIC codes. The electric generating industry comprises the following three SIC codes:

- 4911 – Electric services;
- 4931 – Electric and other services combined; and
- 4939 – Combination utilities, not elsewhere classified.

As explained in Section 3.3.1 of this report, facilities that were categorized as combination utilities within SIC code 4939 were excluded from the analyses presented for the regulated steam electric industry. This industry classification was instead investigated as a potential new subcategory for the current Steam Electric ELGs. The combination utilities industry is further discussed in Chapter 8 of this report.

While facilities categorized within SIC codes 4911 and 4931 are primarily engaged in the generation of electricity, they are not necessarily *regulated* steam electric facilities for the following two reasons:

1. The facility may not use fossil or nuclear fuels; and/or

2. The facility may not use a steam/water system as the thermodynamic medium[16].

EPA linked the PCS database to the EIA database to determine how well SIC codes 4911 and 4931 represent the regulated steam electric industry[17]. By linking the facility records contained in these databases, EPA was able to associate the PCS wastewater discharge information with the EIA design and operation data. There are 864 electric generating facilities within SIC codes 4911 and 4931 that reported discharges in the 2002 PCS database [U.S. EPA, 2006a] and 1,157 regulated steam electric facilities in the EIA database [U.S. DOE, 2002a][18]. EPA was not able to link all 864 PCS electric generating facilities to the EIA data due to insufficient information contained in one or more databases. Of the 864 PCS electric generating

[16] Refer to the electric generating industry subgroup definitions, provided in Section 3.0 of this report.
[17] For more details on how EPA linked the PCS and TRI databases to the EIA database, see the *Preliminary Engineering Report: Steam Electric Detailed Study* [U.S. EPA, 2005b].
[18] For more details on how EPA estimated the number of regulated steam electric facilities from the EIA database, see Section 3.3.2.

facilities, EPA identified 588 in the 2002 EIA data. All but four of these facilities are believed to be regulated steam electric facilities, based on their available EIA data.

To determine how well the available PCS data for electric generating facilities within SIC codes 4911 and 4931 represent the regulated steam electric industry, EPA compared the amount discharged by the 864 electric generating facilities to the amount discharged by the 584 facilities believed to be within the regulated steam electric industry. The discharge amounts are presented as TWPEs[19]. This comparison is presented in Table 5-2.

Table 5-2. Comparison of PCS Discharge Data for All Electric Generating Facilities vs. Regulated Steam Electric Facilities

Type of Discharger	All Electric Generating Facilities[a]		Regulated Steam Electric Facilities[b]		Percentage of Total Load Represented by Regulated Steam Electric Facilities
	Number of Facilities	Pollutant Load (TWPE)	Number of Facilities	Pollutant Load (TWPE)	
Major	556	979,632	490	917,221	94%
Minor	308	77,499	94	49,694	64%
Total	864	1,057,131	584	966,915	91%

Sources: U.S. EPA, 2006a and U.S. DOE, 2002a.
[a]Includes all facilities that reported to PCS within SIC codes 4911 and 4931.
[b]Includes the subset of PCS electric generating facilities that are believed to be regulated steam electric facilities (based on available EIA data).

Although, only 584 out of the 864 PCS electric generating facilities are believed to be regulated steam electric facilities (i.e., 86 percent), their discharges account for approximately 91 percent of the total discharged by all electric generating facilities.

EPA used this comparison to validate using the PCS discharge data from all electric generating facilities to represent the regulated steam electric industry in these analyses. The linkage between the PCS and EIA databases demonstrates that the majority of the electric generating industry reporting discharges to PCS are regulated steam electric facilities (at least 68 percent overall), and that most of the reported pollutant loads (91 percent overall) are attributable to these regulated steam electric facilities.

While 276 of the 864 PCS electric generating facilities are not known to be regulated steam electric facilities, the discharges from non-steam-electric facilities are likely to be minimal, consisting of metal cleaning and other low-volume wastes. Therefore, including these facilities should not grossly impact the PCS pollutant loadings analyses for the regulated steam electric industry.

[19] To compute a TWPE for each parameter reported, the estimated mass (in pounds) of the chemical discharged is multiplied by its TWF. Additional information on the calculation of TWPE and the PCS loading calculations can be found in the *2005 Screening-Level Analysis Report* [U.S. EPA, 2005a].

5.2 Annual Pollutant Loadings

During the preliminary review of the steam electric industry, EPA identified the pollutants reported to be discharged by steam electric facilities, and created a preliminary ranking of these pollutants by discharge load and TWPE. Since the publication of the *Preliminary Engineering Report: Steam Electric Detailed Study*[20], EPA revised the pollutant rankings by incorporating the following changes:

- Updating facility-specific data, based on public comments to the 2006 Preliminary Plan [70 FR 51042; August 29, 2005], including correcting certain loading calculations to better account for batch discharges and intake pollutants (completed on a site-specific basis);

- Revising the average number of days used to estimate biocide discharges, based on UWAG survey data [UWAG, 2005a];

- Including data from minor dischargers in the calculation of pollutant loadings; and

- Deleting chlorine releases and transfers reported in the TRI database from the calculation of pollutant loadings.

EPA examined wastewater data reported to PCS and TRI in evaluating the annual pollutant loadings from the steam electric industry. Section 5.2.1 discusses the TRI data and 5.2.2 discusses the PCS data.

5.2.1 TRI Wastewater Releases and Transfers

Table 5-3 presents the pollutant loads reported to TRI in 2002 for electric generating facilities within SIC codes 4911 and 4931. The pollutant loads in Table 5-3 (shown as "Total Load" in pounds and TWPE) include both direct discharges to surface waters and indirect discharges (i.e., transfers to POTWs, accounting for estimated POTW removals).

Table 5-3 shows that metal discharges contribute most of the TWPE for the industry. Several of the metals, especially arsenic, mercury, and selenium, are typically associated with discharges from coal-fired steam electric facilities because these chemicals are constituents of coal.

[20]The *Preliminary Engineering Report: Steam Electric Detailed Study* [U.S. EPA, 2005b] describes the preliminary analyses of the steam electric industry that EPA conducted in 2005.

Table 5-3. Steam Electric TRI 2002 Pollutant Loads

Chemical Name[a]	Number of Facilities Reporting Chemical	Total Load (pounds)[b]	Total Load (TWPE)[b]	Percentage of Total TWPE
Arsenic and Arsenic Compounds	119	92,117	372,277	45%
Copper and Copper Compounds	196	300,568	190,807	23%
Lead and Lead Compounds	249	37,671	84,383	10%
Mercury and Mercury Compounds	153	505	59,169	7%
Manganese and Manganese Compounds	188	494,560	34,833	4%
Selenium and Selenium Compounds	29	28,723	32,208	4%
Zinc and Zinc Compounds	206	264,899	12,420	1.5%
Nickel and Nickel Compounds	172	111,532	12,147	1.5%
Chromium and Chromium Compounds	159	88,999	6,737	0.8%
Vanadium and Vanadium Compounds	103	124,599	4,361	0.5%
Polycyclic Aromatic Compounds	9	28	2,791	0.3%
Thallium and Thallium Compounds	16	2,363	2,427	0.3%
Barium and Barium Compounds	242	846,321	1,685	0.2%
Beryllium and Beryllium Compounds	17	1,303	1,377	0.17%
Cobalt and Cobalt Compounds	45	10,692	1,222	0.15%
Dioxin and Dioxin-Like Compounds	2	0.000042	443	0.05%
Nitrate Compounds	3	516,350	386	0.05%
Ammonia	45	95,043	105	0.01%
Antimony and Antimony Compounds	14	5,053	62	0.01%
Polychlorinated Biphenyls	1	0.0012	41	<0.01%
Hexachlorobenzene	1	0.020	39	<0.01%
Toluene	2	4,200	24	<0.01%
N-Hexane	3	6.7	0.24	<0.01%
Molybdenum Trioxide	2	253	0.20	<0.01%
1,2,4-Trimethylbenzene	3	6.7	0.19	<0.01%
Methanol	1	6,604	0.10	<0.01%
Hydrogen Fluoride	3	2,720	0.015	<0.01%
Hydrochloric Acid (1995 and After "Acid Aerosols" Only)	3	315	0.0077	<0.01%
Sulfuric Acid (1994 and After "Acid Aerosols" Only)	1	5.0	0.0067	<0.01%
Formic Acid	1	13	0.0048	<0.01%
Benzo(g,h,i)Perylene	9	22	NA	NA
Total for all Pollutants	**368**	**3,035,469**	**819,943**	**100%**

Source: U.S. EPA, 2006b.
[a]This table includes discharges of all pollutants reported to TRI in 2002 by steam electric facilities except for chlorine, as discussed in Section 5.2.1.
[b]The Total Load (pounds and TWPE) include both direct surface water discharges and indirect discharges (i.e., transfers to POTWs, accounting for the POTW removals).
NA – Not applicable. EPA has not developed a toxic weighting factor for this pollutant.

In this analysis, EPA deleted the chlorine releases and transfers that were reported to TRI because the TRI chemical "chlorine" refers to chlorine gas (Cl_2), not total residual chlorine (TRC). Thirteen steam electric facilities reported chlorine discharges to TRI in 2002. The February 2000 *TRI Guidance for Electricity Generating Facilities* describes chlorine releases as follows:

> "No releases to water of chlorine are typically expected. Chlorine reacts very quickly with water to form HOC1, C1-, and H+. Although this is an equilibrium reaction, at a pH above 4, the equilibrium shifts almost completely toward formation of these products. Therefore, essentially zero releases of chlorine to water are expected to occur under normal circumstances." [U.S. EPA, 2000]

From Table 5-3, the top TRI pollutants identified for the steam electric industry are arsenic and copper, each contributing over 100,000 TWPE.

5.2.2 PCS Wastewater Discharges

Table 5-4 presents the top 15 pollutant loads (by TWPE) estimated from the PCS discharge data reported in 2002, as well as loads for four additional pollutants that were included in the study. These loads incorporate the corrections previously described in Section 5.2. As a result of these corrections, the pollutant load estimates have changed since the publication of the 2005 *Preliminary Engineering Report: Steam Electric Detailed Study* [U.S. EPA, 2005b]. Note, however, that the top five PCS pollutants, aluminum, arsenic, boron, chlorine, and copper, (each contributing more than 100,000 TWPE) have not changed as a result of the corrections.

The detailed study focused its research efforts on the top five pollutants by TWPE; however, EPA also collected and analyzed PCS data for several other pollutants for which it received comments. The additional pollutants included in these analyses are mercury, nickel, zinc, five-day biochemical oxygen demand (BOD_5), total suspended solids (TSS), and total phosphorus (total P). The 2002 PCS loads for these additional pollutants are included in Table 5-4. The results of the analyses and research on these 11 pollutants of interest are described in the remaining sections of this chapter.

5.3 Concentration Analyses of Steam Electric Pollutants

EPA used available data in PCS to compute the range, average, and median concentrations that were reported for each of the 11 pollutants of interest. Table 5-5 presents these data, along with the number of times the pollutant was detected.

Facilities report pollutant discharge data to PCS as a maximum quantity, average quantity, maximum concentration, average concentration, or minimum concentration. EPA used only the average concentration data reported from both major and minor dischargers from the year 2002 for this analysis. EPA also only included average concentration measurements that were reported with an associated flow rate. These average concentration data were available for 628 of the 864 major and minor electric generating facilities reporting to PCS.

Table 5-4. Steam Electric PCS 2002 Pollutant Loads for Selected Pollutants

Pollutant	Number of Facilities Reporting >0 Pounds of Pollutant	Total Load (pounds)	Total Load (TWPE)	Rank
Copper	214	318,114	201,946	1
Aluminum	53	3,040,130	196,670	2
Arsenic	55	46,359	187,352	3
Boron	28	1,007,098	178,473	4
Chlorine	279	257,551	131,135	5
Selenium	68	28,892	32,398	6
Lead	44	8,822	19,762	7
Fluoride	13	488,405	17,094	8
Iron	176	2,709,160	15,171	9
Mercury	31	111	13,019	10
Cadmium	25	541	12,513	11
Zinc	163	237,219	11,122	12
Manganese	41	108,565	7,647	13
Hexavalent Chromium	12	12,068	6,234	14
Cyanide	12	3,981	4,446	15
Nickel	53	27,948	3,044	17
TSS	605	502,018,895	NA	NA
BOD_5	172	3,618,349	NA	NA
Total P	79	1,809,019	NA	NA
Total for all Pollutants[a]	**718**	**20,239,849,061**	**1,057,131**	

Source: U.S. EPA, 2006a.
[a]The totals shown represent all facility pollutant load data reported to PCS in 2002. The table shows individual pollutant loads for the top 15 pollutants (by TWPE), as well as an additional four pollutants that were selected for the study.
NA – Not applicable. EPA has not developed TWFs for these pollutant parameters. EPA only ranked pollutants for which it has developed a TWF and calculated TWPE loads.

For average concentration measurements reported as below the detection limit, EPA assumed that the average concentration was equal to one-half the detection limit if at least one other sample from that outfall was detected. Alternatively, EPA assumed the average concentration was equal to zero if the pollutant was not detected in any of the samples reported from the outfall. EPA included only non-zero concentrations in determining the ranges (i.e., minimums and maximums) in the reported average concentrations, as well as in determining the medians and averages of reported concentrations. Of the 11 pollutants included in the analysis, only four are specifically limited by national discharge standards for the steam electric industry [40 CFR 423]: chlorine, copper, zinc, and TSS[21]. According to the available PCS data, these four pollutants were mostly discharged at concentrations below the current regulatory limits.

EPA compared effluent discharge concentrations to the pollutant's detection limit. Detection limits can vary based on a number of factors, including the specific analytical method and wastewater matrix. Because the parameters may be measured by different methods, Table 5-5 presents a "sample-specific median" method detection level (MDL). The median MDL is calculated from all reported MDLs reported to PCS for the parameter. MDLs are reported only when the pollutant is not detected in the sample; therefore, the median MDL shown may not reflect actual MDLs for samples in which the pollutant was detected.

EPA reviewed the average concentration data that were available in PCS to determine the number of times a pollutant was detected at 10 times the sample-specific median MDL. EPA believes that average pollutant concentrations at this level provide a sufficient level of confidence that the pollutant is present in the waste stream. That is not to say, however, that if a pollutant is measured at concentrations less than 10 times the detection limit, it is <u>not</u> present in the waste stream. On the contrary, and particularly with steam electric wastewaters, the presence of some pollutants may be masked due to extreme dilution when low-volume, high-strength waste streams are combined with high-volume, low-strength waste streams. This is especially important in the case of persistent and bioaccumulative pollutants, such as mercury, which can pose significant hazards to human health and the environment even at low concentrations. While effects of this dilution may appear to minimize their presence in the final effluent, the hazard associated with the discharge may be significant.

Boron, aluminum, total phosphorus, zinc, and arsenic were all detected at this level more than 10 percent of the time. Boron discharged from fossil fuel facilities was detected in nearly all reported samples (99 percent) at levels greater than 10 times the sample-specific median MDL. Copper, chlorine, nickel, TSS, mercury, and BOD_5 were all detected at levels greater than 10 times the sample-specific median MDL less than 10 percent of the time.

[21] Arsenic, mercury, and nickel are also regulated under 40 CFR 423 as priority pollutants. These pollutants must not be detectable in cooling tower blowdown.

Table 5-5. Summary of Average Pollutant Discharge Concentrations Reported to PCS

Pollutant	Existing Regulatory Limit[a] (ug/L)	Number of Detects	Number of Non-Detects	Range of Concentrations (ug/L)[b]	Average Concentration (ug/L)[b]	Average Concentration for Detected Values (ug/L)	Median Concentration (ug/L)[b]	Sample-Specific Median MDL (ug/L)	Number of Detects Greater than 10× Sample-Specific Median MDL	Percentage of Detects Greater than 10× Sample-Specific Median MDL
Copper	1,000	1,250	275	0.0005 - 50,000	307	339	18	10	110	7.2%
Aluminum	NR	367	37	1 - 73,100	2,297	2,407	360	100	98	24%
Arsenic	NR	106	105	0.22 - 394	57	70	40	8	24	11%
Boron:										
Fossil Fuel	NR	85	0	1.99 - 369,000	44,813	44,813	4,760	1	84	99%
Nuclear	NR	5	6	0.5 - 11,300	1,937	4,261	1		2	18%
Chlorine	200	1,131	449	0.005 - 3,380	152	171	54	50	91	5.8%
Mercury	NR	36	65	0.0002 - 40.56	3	4	0.1	4	1	1.0%
Zinc	1,000	1,003	161	0.03 - 10,700	174	190	37	20	159	14%
Nickel	NR	169	98	0.14 - 1,950	115	132	30.1	40	10	3.7%
TSS	30,000	9,695	1,181	33.3 - 3,592,000	16,305	17,621	6,000	4,000	273	2.5%
BOD_5	NR	735	182	250 - 117,000	7,285	8,236	4,800	4,000	11	1.2%
Total P	NR	411	9	5 - 70,000	904	923	200	75	95	23%

Source: U.S. EPA, 2006g.
[a]See 40 CFR 423. Limits shown are either average of daily values for 30 days or the average concentration limit.
[b]For average concentration measurements reported as below the detection limit, EPA assumed that the average concentration was equal to one-half the detection limit if at least one other sample from that outfall was detected. If the pollutant was not detected in any of the samples reported from the outfall, it was not included in the analysis.
NR - Not regulated.
MDL - Method detection limit.

EPA next evaluated the reported effluent concentrations for four of the identified pollutants by waste stream, shown in Table 5-6. Where possible, EPA identified the type of waste stream being reported in PCS. If insufficient information was available, EPA classified the waste stream as "unknown." EPA used the same methodologies for analyzing the pollutant concentrations for this analysis as was previously discussed. EPA compared the sample-specific median MDL to the average concentration and identified discharges that were greater than 10 times the sample-specific MDL. EPA also identified the number of facilities and the number of discharge pipes (outfalls) that were included in the analysis.

EPA performed the concentration analysis by waste stream for the top pollutants identified through the pollutant loads analysis, excluding chlorine. EPA did not separate the chlorine concentrations by waste streams because it had already identified cooling water systems as the primary source of chlorine discharges.

5.4 Sources and Concentrations of the Pollutants of Interest in Steam Electric Waste Streams

EPA identified the top five pollutants (copper, aluminum, arsenic, boron, and chlorine) by TWPE that were reported to be discharged by the steam electric industry in PCS and TRI, as discussed in Section 5.2. These top pollutants contributed 100,000 or more TWPE, and account for 85 percent of the total steam electric PCS TWPE and 69 percent of the total steam electric TRI TWPE. EPA also evaluated pollutants that were identified in public comments to the 2006 Preliminary Plan [70 FR 51042; August 29, 2005]: BOD_5, mercury, nickel, total phosphorus, TSS, and zinc. This section presents information on each pollutant, including the wastewater sources that are typically associated with the pollutant and typical concentrations of the pollutant in steam electric waste streams[22].

EPA reviewed the 1974 and 1982 Development Documents to determine if TSS limits were previously set at a level to control other pollutants. EPA also used the concentration analysis by waste stream to determine whether the average or median concentration is greater than 10 times the sample-specific median MDL and which waste stream had pollutant concentrations at these levels. Table 5-7 summarizes the current pollutant data and preliminary conclusions.

Although not specifically discussed in this section, EPA anticipates greater amounts of nitrogen compounds, selenium, and other metals in steam electric wastewaters as a result of the increasing use of air pollution controls. SCR systems used to control NO_x in boiler emissions will increase ammonia use, and some of this ammonia and other nitrogen-containing by-products are expected to be contained in the cleaning wastewater from these systems. Other wet air pollution controls (e.g., FGD) are also believed to contribute selenium and other metals to steam electric wastewaters.

[22] Typical concentrations presented in this section are based on data previously collected by EPA during the 1974 and 1982 rulemaking efforts.

Table 5-6. Summary of Average Pollutant Discharge Concentrations Reported to PCS by Waste Stream

Pollutant	Waste stream	Number of Detects	Number of Non-Detects	Range of Concentrations (ug/L)[a]	Average Concentration (ug/L)[a]	Average Concentration for Detected Values (ug/L)	Median Concentration (ug/L)[a]	Sample-Specific Median MDL (ug/L)	Number of Detects Greater than 10× Sample-Specific Median MDL	Is Avg. Conc. >10× Sample-Specific Median MDL	Number of Discharge Pipes	Number of Facilities
Copper, Total	Unknown Discharge	392	63	0.0013 - 35,820	126	138	18	10	33	Yes	64	54
	Cooling Tower Blowdown	48	11	0.06 - 1,000	100	117	30.4	10	12	No	12	10
	Other Cooling Water	81	9	0.0005 - 50,000	3,505	3,894	11	10	13	Yes	12	10
	Ash Handling Discharges	160	46	1 - 124	15	15	12.6	10	1	No	27	21
	Coal Pile Runoff	16	15	5 - 3,550	903	1,183	10	10	6	Yes	5	5
	Metal Cleaning Waste	45	50	0.006 - 1,260	94	109	20	10	8	No	29	29
	Low-Volume Waste	151	28	0.0101 - 800	62	67	32.75	10	16	No	18	15
	Boiler Blowdown	3	0	13 - 86	43	43	31	10	0	No	1	1
	Final Effluent	164	0	0.0275 - 357.3	34	34	15.15	10	13	No	23	15
	Stormwater	22	0	1 - 532	81	81	71.55	10	2	No	6	3
	Flue Gas Desulfurization Waste	5	8	4 - 20	8	11	5	10	0	No	2	2
	Wastewater Treatment	163	45	1.5 - 350	25	27	16	10	6	No	24	23
	Total	***1,250***	***275***		***307***	***339***			***110***		***223***	***155***
Aluminum, Total	Unknown Discharge	128	19	9.5 – 8,708	666	731	335	100	32	No	22	17
	Cooling Tower Blowdown	42	2	3 – 5,100	905	947	530	100	13	No	5	3
	Other Cooling Water	11	0	240 – 2,000	591	591	460	100	1	No	1	1
	Ash Handling Discharges	47	1	25 – 6,180	1,079	1,101	434	100	17	Yes	7	6
	Coal Pile Runoff	38	0	100 – 73,100	16,157	16,157	1,000	100	17	Yes	5	5
	Metal Cleaning Waste	0	2	ND	ND	ND	ND	100	0	No	1	1
	Low-Volume Waste	24	0	70 – 5,520	2,200	2,200	2,060	100	15	Yes	2	2
	Stormwater	34	1	1 – 1,528	286	295	231	100	1	No	3	3
	Wastewater Treatment	43	12	67.5 – 1,900	348	348	260	100	2	No	5	5
	Total	***367***	***37***		***2,297***	***2,407***			***98***		***51***	***34***

Table 5-6 (Continued)

Pollutant	Waste stream	Number of Detects	Number of Non-Detects	Range of Concentrations (ug/L)[a]	Average Concentration (ug/L)[a]	Average Concentration for Detected Values (ug/L)	Median Concentration (ug/L)[a]	Sample-Specific Median MDL (ug/L)	Number of Detects Greater than 10× Sample-Specific Median MDL	Is Avg. Conc. >10× Sample-Specific Median MDL	Number of Discharge Pipes	Number of Facilities
Arsenic, Total	Unknown Discharge	24	25	1.1 - 156	35.6	45.0	12	8	4	No	13	11
	Cooling Tower Blowdown	1	0	0.22	0.2	0.2	0.22	8	0	No	1	1
	Ash Handling Discharges	50	3	1.76 - 394	84.2	88.8	54.5	8	18	Yes	7	7
	Coal Pile Runoff	1	15	10 - 30	12.0	30.0	10	8	0	No	3	3
	Metal Cleaning Waste	0	3	ND	ND	ND	ND	8	0	No	1	1
	Low-Volume Waste	0	14	ND	ND	ND	ND	8	0	No	4	2
	Final Effluent	28	0	13.8 - 216	66.8	66.8	65	8	2	No	3	3
	Flue Gas Desulfurization Waste	1	0	10	10.0	10.0	10	8	0	No	1	1
	Wastewater Treatment	1	45	10 - 20	11.4	20.0	10	8	0	No	5	5
	Total	***106***	***105***		***57***	***70***			***24***		***38***	***28***
Boron-Fossil Fuel	Other Cooling Water	10	0	200 - 800	561	561	600	1	10	Yes	2	1
	Ash Handling Discharges	15	0	1.99 - 1,860	1,057	1,057	1,290	1	14	Yes	3	2
	Stormwater	10	0	10000 - 38,000	23,100	23,100	24,000	1	10	Yes	1	1
	Flue Gas Desulfurization Waste	38	0	2210 - 369,000	93,356	93,356	87,050	1	38	Yes	5	3
	Wastewater Treatment	12	0	340 - 1,450	758	758	615	1	12	Yes	1	1
	Total	***85***	***0***		***44,813***	***44,813***			***84***		***12***	***7***
Boron-Nuclear	Unknown Discharge	3	6	0.5 - 4	1	2	1	1	0	No	1	1
	Nuclear Discharges	2	0	10,000 - 11,300	10,650	10,650	10,650	1	2	Yes	1	1
	Total	***5***	***6***		***1,937***	***4,261***			***2***		***2***	***2***

Source: U.S. EPA, 2006g.
[a]For average concentration measurements reported as below the detection limit, EPA assumed that the average concentration was equal to one-half the detection limit if at least one other sample from that outfall was detected. If the pollutant was not detected in any of the samples reported from the outfall, it was not included in the analysis.
ND - Not detected.
MDL - Method detection limit.

Table 5-7. Summary of Pollutant Analysis

Pollutant	Existing Regulatory Limit (ug/L)	Previously Controlled with Surrogate Parameter (i.e., TSS)?	Is Average Concentration >10X Sample-Specific Median MDL?[a]	Is Median Concentration >10X Sample-Specific Median MDL?[a]	Waste Streams with Average or Median Concentration >10X Sample-Specific Median MDL
Boron:					
Fossil Fuel	NR	Not discussed	Yes	Yes	FGD waste, stormwater, ash handling, wastewater treatment, and cooling water
Nuclear	NR	Not discussed	Yes	Yes	Not analyzed
Aluminum	NR	Not discussed	Yes	Yes	Low-volume waste, coal pile runoff, and ash handling
Arsenic	NR	No	Yes	No	Ash handling
Copper	1,000	No	Yes	No	Cooling water, coal pile runoff, cooling tower blowdown, and metal cleaning waste
Chlorine	200	No	No	No	NA
Zinc	1,000	Not discussed	No	No	NA
Mercury	NR	Not discussed	No	No	NA
Nickel	NR	Not discussed	No	No	NA
Total P	NR	Not discussed	Yes	No	Not analyzed
TSS	30,000	NA	No	No	NA
BOD_5	NR	Not discussed	No	No	NA

[a]PCS data showing concentrations >10X MDL demonstrates that the pollutants are present in significant concentrations. Concentrations <10X MDL are inconclusive because there is insufficient information to determine whether other waste streams are diluting the concentrations.
NA – Not Applicable.
NR – Not Regulated.
Not Discussed – The Development Documents did not specifically mention a correlation between the control of the pollutant and TSS.
Not Analyzed – A waste stream concentration analysis was not performed on the pollutant.

5.4.1 Copper

Copper is a pollutant associated with metal cleaning, for which it is limited to discharges of 1 mg/L. Copper is also present in cooling water systems as a result of the dissolution of copper ions from the tubes and into the water, as well as corrosion. Because it is added as a boiler system maintenance chemical to prevent scale formation, copper is present in low-volume waste streams, such as boiler blowdown. Copper is also associated with coal-fired plants as a constituent of coal [U.S. EPA, 2000]. From analyses supporting the 1982 rulemaking, copper has been shown to increase in concentration in recirculating cooling water systems by 100 ug/L or more, and be present in boiler blowdown in discharge concentrations of up to 140 ug/L [U.S. EPA, 1982].

Except for chemical metal cleaning wastes and cooling tower blowdown, copper was not previously regulated under 40 CFR 423 because it was not detected or because it was detected in amounts too small to be effectively reduced by wastewater treatment technologies [U.S. EPA, 1982]. In the case of coal pile runoff, copper was believed to be sufficiently controlled through the regulation of TSS [U.S. EPA, 1982]; however, it should also be noted that for ash pond overflows, EPA concluded that there was no correlation between TSS values and copper concentrations in the water [U.S. EPA, 1982].

Average copper concentrations reported for coal pile runoff and "other cooling water" were more than 10 times the sample-specific median MDL; however, the coal pile runoff concentrations are driven by six measurements reported by one facility, out of a total of 21 measurements from four facilities. If the six measurements from the one facility are removed from the analysis, the average copper concentration for coal pile runoff is 15 ug/L, which is just above the sample-specific median MDL. The "other cooling water" concentrations are driven by eight measurements reported by one facility, out of a total of 90 measurements from 10 facilities. If the eight measurements from the one facility are removed from the analysis, the average copper concentration for "other cooling water" is 24 ug/L, which less than 10 times the sample-specific median MDL. The median discharge concentration of approximately 10 ug/L is two orders of magnitude less than the average concentration.

It should be noted that while the pollutant concentration in some waste streams is not high, the total loading of that pollutant discharged to the environment can be still be significant. This is particularly the case with high-volume waste streams, such as cooling water discharges.

5.4.2 Aluminum

Aluminum is associated with coal-fired plants as a constituent of the coal. Aluminum oxide may be present in coal ash in amounts ranging between 4 and 44 weight percent [U.S. EPA, 1982]. Wastewater streams associated with coal, such as ash handling and coal pile runoff, can become contaminated with aluminum.

Aluminum was previously identified as a constituent of coal pile runoff, but was not specifically regulated. There are several factors that affect the presence of aluminum (and other metals) in coal pile runoff, including the pH of the drainage, the type of coal, the size of the coal, climatic conditions, and other factors [U.S. EPA, 1982]. Aluminum is likely controlled to some degree by the control of TSS, but there is no demonstrated correlation between TSS and aluminum concentrations.

For aluminum, the highest reported concentrations (73,100 ug/L) are associated with coal pile runoff. However, the reported discharge concentrations are primarily driven by 10 measurements from one facility, out of a total of 38 measurements from five facilities. If the 10 measurements from the one facility are removed from the analysis, the average aluminum concentration for coal pile runoff is 880 ug/L, which is less than 10 times the sample-specific median MDL. Higher concentrations of aluminum discharges (up to 6,000 ug/L) are also associated with low-volume wastes and ash handling. Because aluminum is a constituent of coal, it is not surprising that aluminum is present in waste streams associated with coal, such as coal pile runoff. EPA identified best management practices as a way that aluminum discharges from coal pile runoff could be prevented [U.S. EPA, 1974]. Aluminum is not currently regulated by the Steam Electric ELGs.

5.4.3 Arsenic

Arsenic is also associated with coal-fired power plants as a constituent of coal. Wastewater streams associated with coal, such as ash handling and coal pile runoff, can become contaminated with arsenic; however, the arsenic content of coal can vary widely depending on the coal's rank (e.g., bituminous, lignite, subbituminous) and the region of the country in which the coal originates. For example, bituminous coal from Alabama has an arsenic content of 53 ug/g, while subbituminous coal from Wyoming has an arsenic content of 0.69 ug/g [U.S. EPA, 2000]. In general, coal from Alabama has an average arsenic content of 72.4 ug/g, while on average, coal in the United States has an arsenic content of 24.6 ug/g [USGS, 1998].

Except for cooling tower blowdown, arsenic was not previously regulated under steam electric because EPA found that it was not detected or was detected in amounts too small to be effectively reduced by wastewater treatment technologies [U.S. EPA, 1982]. It should also be noted that in the 1982 Development Document, EPA specifically concluded that there was no correlation between TSS values and arsenic in ash pond overflows [U.S. EPA, 1982].

The average arsenic concentrations associated with ash handling waste streams were greater than 10 times the sample-specific median MDL. Arsenic was detected at this level in 34 percent of the available PCS data (i.e., in 18 out of 53 records); however, the median arsenic concentration associated with ash handling waste streams was less than 10 times the sample-specific median MDL. In the 1982 rulemaking, EPA identified chemical precipitation as a potential control technology for arsenic discharges from ash handling waste streams [U.S. EPA, 1982].

5.4.4 Boron

Boron is a pollutant associated with both nuclear and fossil-fuel type steam electric plants. EPA's finding with respect to boron discharged from each of these sources are summarized below.

Boron from Fossil-Fuel Plants

In fossil-fuel plants, boron is associated with coal-fired plants specifically as a constituent of the coal. Coals vary in terms of their trace metal composition depending on their rank (e.g., bituminous, lignite, subbituminous) and the region of the country in which they originate. For example, coal from Alabama has a boron content of 28.2 ug/g, while on average, coal in the United States has a boron content of 47.9 ug/g [USGS, 1998]. Therefore, wastewater streams associated with coal, such as wet ash handling and coal pile runoff, can become contaminated with boron.

In addition, waste streams generated by FGD systems can also contain amounts of boron removed from the flue gas emissions (see Section 3.2.1.6 for a discussion of FGD). FGD systems remove sulfur dioxide from the exhaust of coal-fired power plants, and by extension these waste streams may be a source of boron and other coal constituents (e.g., arsenic and other metals).

Boron was not previously identified as a pollutant of concern for the steam electric industry because no practicable treatment was reported [U.S. EPA, 1974]. It is likely controlled to some degree by controlling TSS, but there is no demonstrated correlation between TSS and boron concentrations [U.S.EPA, 1974].

For boron discharged from fossil-fuel plants, EPA determined that highest reported concentrations reported in PCS were associated with FGD systems. Average concentrations ranged from 2,210 to 369,000 ug/L, with a median reported concentration of 87,050 ug/L. Boron was also reported in high concentrations associated with stormwater (median concentration of 24,000 ug/L). Because boron is a constituent of coal, it is not surprising that boron is present in FGD waste streams. EPA identified a zero liquid discharge brine concentrator/spray dryer system that is designed to remove boron and other metals from FGD waste streams (see Section 5.5.2 for more details). Boron is not currently regulated by 40 CFR 423.

Boron from Nuclear-Fueled Plants

In nuclear plants, boron is typically used to absorb neutrons, which controls the fate of the fission chain reaction [EaglePicher, 2002]. Various forms of boron compounds, including boric acid and sodium pentaborate, may be added to the primary coolant system to help control the long-term stability of the system [EaglePicher, 2002]. Boron-enriched zirconium diboride and erbium boride may be used as nuclear fuel additives to control the absorption of neutrons to better control the reaction. EPA determined that possible sources of boron discharges from nuclear facilities include the following [UWAG, 2005b] [UWAG, 2006a] [69 FR 18654; April 18, 2004]:

- High conductivity waste tank;
- Radioactive waste hold-up tank;
- Standby liquid control drain tank;
- Steam generator blowdown;
- Spent fuel pond; and
- Treatment processes.

For boron discharged from nuclear plants, EPA estimated the highest reported average concentrations were over 11,300 ug/L, and the median of the average concentrations was 10,650 ug/L.

5.4.5 Chlorine

Chlorine and chlorine-based compounds are primarily used as biocides in power plant cooling water systems to control biofouling in either closed- or open-loop systems. Biofouling is the collection of slime-forming organisms (fungi, bacteria) or larger organisms (clams, mussels) on the water side of the condenser tubes, which inhibits heat exchange. Chlorine's effectiveness as a biofouling control agent also makes it an aquatic environmental concern due to its potential direct impact when residual chlorine is released.

Some steam electric facilities currently use alternatives to chlorine-based oxidizing biocides, such as brominated compounds, for biofouling control. Other alternatives include non-oxidizing biocides, such as ammonium compounds, aromatic hydrocarbons, copper salts, potassium salts, and many others [Sprecher, 2000].

UWAG conducted a survey of its members and provided the results to EPA [UWAG, 2005a]. In the survey, UWAG obtained information regarding biocide usage in the industry. Table 5-8 summarizes the relative number of facility respondents using various types of biocide.

Table 5-8. Biocide Usage in the Steam Electric Industry

Biocide	Number of Units	Percentage of Survey Respondents
Chlorine-based compounds only	414	49.3%
Bromine-based compounds only	44	5.2%
Both chlorine and bromine based compounds	70	8.3%
Both chlorine or bromine and non-oxidizing biocide	8	0.95%
Non-oxidizing biocides only	7	0.83%
Ozonation	2	0.2%
Total Units Using Biocides	545	64.8%

Source: UWAG, 2006b.

Chlorine was identified previously as a key pollutant for this industry. During sampling in support of the 1982 rulemaking, net discharges of TRC were as high as 7,100 ug/L in once-through and recirculating systems [U.S. EPA, 1982]. Chlorine is currently regulated as TRC in once-through cooling system wastewaters, and as free available chlorine (FAC) for recirculating cooling tower system wastewaters. Brominated compounds are regulated as total residual oxidants (TRO) by 40 CFR 423 for once-through cooling water from plants having a total rated electric generating capacity of 25 MW or more if the intake water contains bromides [40 CFR 423.11(a)]. Non-oxidizing biocides are not directly regulated by 40 CFR 423, but the ELG limitation of no detectable priority pollutants in cooling tower blowdown would apply.

According to the available PCS average concentration data for the TRC and FAC parameters, chlorine is typically discharged at levels much lower than the current ELG limits. EPA has identified a number of best management practices as well as treatment technologies to achieve nondetectable quantities of chlorine in cooling water effluent (see Section 5.5.1 for more details).

It should be noted that while the pollutant concentration in some waste streams is not high, the total loading of that pollutant discharged to the environment can be still be significant. This is particularly the case with high-volume waste streams, such as cooling water discharges.

5.4.6 Mercury

Mercury is a trace constituent of all fossil fuels, including coal, oil, and natural gas [U.S. EPA, 2001a]. The trace metal composition of coals varies depending on their rank (e.g., bituminous, lignite, subbituminous) and the region of the country in which they originate. The average mercury content in coal is 0.17 mg/kg [USGS,1998]. Wastewater streams associated with coal, such as ash handling and coal pile runoff, can become contaminated with mercury.

Mercury is associated with waste streams from FGD systems because it is a constituent of coal and FGD systems are capable of scrubbing metals out of the flue gas streams (i.e., soluble mercury compounds are expected to be captured by wet FGD systems). EPRI commented that power plants with FGDs are likely to have higher mercury concentrations in wastewater discharges.

Likewise, the use of SCR systems is expected to increase the amount of mercury removed from the facility exhaust stream. Mercury that is adsorbed to fly ash and other particulates is also likely to be removed by other particulate matter control devices. In addition to FGD and SCR, many steam electric facilities use wet fly ash handling systems, which allows mercury to be transformed from the flue gas exhaust and into wastewater from the air pollution control devices, and subsequently into surface waters. Further, available data indicate that elemental mercury may be oxidized in an SCR unit (particularly when bituminous coal is being used) [U.S. EPA, 2005b]. This increases the amount of oxidized mercury in the gas stream that may then be removed in a downstream wet FGD system.

As described in Chapter 4 of this report, CAMR establishes limits on mercury emissions from the steam electric industry. The first phase of the regulation should not require that the industry implement mercury-specific control technologies to meet the limits. Facilities may continue to use existing SO_2 and NO_x control technologies required by CAIR, such as FGD and SCR. The use of wet FGD systems to capture SO_2 is expected to double by 2015 in response to CAIR [U.S. EPA, 2006c].

EPRI provided data on mercury concentrations detected in steam effluents in the 1990s. EPRI's data, using the 1600 series methods for detecting trace metals, showed effluent concentrations on the order of 0.01 ug/L, which was lower than reported in the 2002 PCS data (3 ug/L on average). The EPRI sampling data were collected from seven facilities, while the PCS data include measurements from 22 facilities. EPRI did not identify which waste streams were sampled in their analyses and, therefore, EPA cannot determine if one data source is better or more accurate than the other. The minimum level of quantitation for Method 1631 is 0.5 ng/L [U.S. EPA, 2002]. EPRI also noted that conventional sampling and analytical methods should be able to achieve detection limits below 0.2 µg/L.

Mercury was reported to be discharged by only 42 out of the 864 facilities reporting to PCS; however, mercury was reported to be discharged by 153 of the 375 facilities reporting to TRI. Therefore, the mercury loads represented in Table 5-4 may be underestimated because many facilities are not required by their NPDES permits to monitor mercury discharges.

In this detailed study, EPA researched available information on IGCC technology (discussed previously in Section 3.2.2) as having the potential to reduce the mercury and other metals released to the water and air from traditional coal-fired boilers. IGCC technology offers opportunities to remove mercury and other trace metals (e.g., cadmium and selenium) from the coal-derived syngas prior to combustion, thus reducing the levels of these contaminants in ash and air pollution control wastes.

5.4.7 Nickel and Zinc

Nickel and zinc are both constituents of coal and, like mercury, can be found in wastewaters associated with the coal and ash. In addition, zinc is often used in corrosion inhibitors, and therefore can also be found in cooling water system discharges.

Nickel was detected in slightly more than 60 percent of the reported samples; however, it was detected at more than 10 times the sample-specific MDL in only 3.7 percent of the samples. The average concentration was 115 ug/L with a median concentration of 31 ug/L.

Zinc is typically (more than 80 percent) detected in all reported samples, but is detected at 10 times the sample-specific MDL in only about 14 percent of the samples. The zinc concentrations were on the order of those for nickel. The average concentration was 174 ug/L with a median concentration of 37 ug/L, well below the existing ELG limit of 1,000 ug zinc/L. The average concentration is primarily driven by three facilities that reported concentrations greater than 1,000 ug/L, out of 1,117 measurements from 109 facilities.

5.4.8 Total Suspended Solids

TSS is a pollutant of concern for this industry and is already regulated under the current ELGs. TSS is an indicator of the effectiveness of solids separation processes. In addition to electric generating process sources, the level of TSS found in steam electric process wastewaters can also be affected by chemical treatment of the wastewater, as certain compounds are precipitated from the waste stream.

EPA identified TSS for further review in the *Preliminary Engineering Report: Steam Electric Detailed Study* because of its large pollutant loading [U.S. EPA, 2005b]. EPA determined that the vast majority of discharges reported for TSS are well below the current ELG limits (i.e., 30 or 50 mg/L, depending on the waste stream), with an average concentration of 16 mg/L and a median concentration of 6 mg/L, based on 10,752 measurements from 525 facilities.

5.5 Pollutant Control Technologies and Practices

This section summarizes potential treatment and control technologies for selected pollutants of interest contained in wastewaters of the steam electric industry, based on information obtained to date for this detailed study. Wastewaters from steam electric plants vary in quality and quantity; however, pollutants in these wastewaters can often be controlled in a uniform manner. The technologies described in this section are available or currently in use by facilities in the steam electric industry. The discussion of technologies is organized by type of waste stream.

5.5.1 Cooling Water Pollutant Control Technologies

As described in Section 3.2, cooling water is used in the steam electric process to condense the steam used to drive the turbine and generate electricity. As the cooling water passes through the condenser, microbiological species, such as bacterial slimes and algae, stick to and begin growing on the condenser tubes. This growth is known as biofouling, which reduces heat transfer, decreases flow, and accelerates corrosion of the condenser. There are also various macro-organisms, such as mussels, mollusks, and clams, which can inhibit condenser performance. Steam electric facilities use biocides, such as chlorine, to control biofouling.

5.5.1.1 Dry Cooling Technology

The vast majority of water used by traditional steam electric facilities is related to cooling water systems. Due in part to water shortages that exist in arid parts of the world, some power plants have implemented dry cooling technology. Dry cooling systems reduce cooling water use by 99 percent compared to once-through cooling systems, and 4 to7 percent compared to recirculating cooling water systems (e.g., cooling towers) [U.S. EPA, 2001b].

Dry cooling systems transfer heat to the atmosphere without water evaporation. There are two types of dry cooling systems for power plant applications: direct dry cooling and indirect dry cooling. Direct dry cooling systems utilize air to directly condense steam, while indirect dry cooling systems use a closed-cycle water cooling system to condense steam, and the heated water is then air cooled. Indirect dry cooling generally applies to retrofit situations at existing power plants because a water-cooled condenser would already be in place for a once-through or recirculated cooling system. The most common type of direct dry cooling systems (towers) for new power plants are recirculated cooling systems with mechanical draft towers. Natural draft towers are infrequently used for installations in the United States [Micheletti, 2002].

5.5.1.2 Recirculating Cooling Water Systems

In a recirculating system, cooling water is used to cool equipment and steam, absorbing heat in the process. The water is then cooled and recirculated to the beginning of the system to be used again for cooling. Recirculating the cooling water in a system vastly reduces the amount of cooling water needed. On average, recirculating cooling systems reduce the cooling water flow rate between 92 and 95 percent compared to once-through cooling systems, depending on the water source [U.S. EPA, 2001b]. The method most frequently used to cool the water in a recirculating system is through a cooling tower (see Section 3.2.1.4 for more details on recirculating cooling water systems).

5.5.1.3 Biocide Management Practices for Once-Through Cooling Systems

This section describes biocide management practices in use at steam electric facilities with once-through cooling systems, including low-level biocide application, natural decay of total residual oxidants (TRO)/free available oxidants (FAO), and dehalogenation.

Low-Level Biocide Application

Typically, facilities perform an optimization study to determine what chemical regime would provide the best results for the plant. A low-level biocide application is the usual treatment option used by facilities with once-through cooling systems. Based on the results of the optimization study, the facility can add a specific amount of biocide that will treat the biofouling in the condensers and still meet the NPDES permit limit or achieve a nondetectable biocide concentration. Alternatively, the facility may inject enough biocide to meet the biological demand with the option to dehalogenate if residuals exist [UWAG, 2006c].

Natural Decay of TRO/FAO with No Dehalogenation System

Facilities can naturally decay TRO/FAO by using a discharge canal or by commingling treated condenser cooling water with untreated condenser cooling water prior to discharge [UWAG, 2006c]. Commingling treated and untreated condenser cooling water requires the facility to have multiple condenser cooling systems and the ability to chlorinate each unit independently. To do this, the facility installs the injection point of the chlorine system at or near each of the condenser inlet boxes [U.S. EPA, 1982]. This practice allows the TRO/FAO to naturally decay because there is less natural dechlorination before the condenser (i.e., if the chlorine was injected into the waste stream at the intake point, instead of right before the condenser), which minimizes chlorine use. In addition, there is some natural dechlorination after the cooling water exits the condenser outlet box. Because there are multiple condenser cooling systems, the untreated cooling water will have some biological demand that will naturally decay some of the remaining biocide from the treated cooling water.

Dehalogenation

Dehalogenation is the process of adding a reducing agent, typically sulfur dioxide, sodium bisulfite, or ammonium bisulfite, to a waste stream to consume the oxidizing biocide present. The bisulfite compounds can be fed as either a solid or liquid, and sulfur dioxide is used as a gas [UWAG, 2006c]. Chlorine is the most commonly used biocide, and sulfur dioxide is the most commonly used dehalogenation chemical, due to its ease of handling and low cost. The chlorine in the wastewater, in the form of hypochlorous acid, oxidizes the sulfur dioxide and produces chloride and sulfate ions.

Water and wastewater treatment facilities have used dehalogenation extensively since 1926 [U.S. EPA, 1982]; this technology is also currently in use at many steam electric power plants. It is a proven technology that can reduce the residual oxidant levels in wastewater to trace or nondetectable concentrations. For more information regarding the use of dehalogenation systems at steam electric power plants, see Section VII of the 1982 Development Document [U.S. EPA, 1982].

5.5.1.4 Biocide Management Practices for Recirculating Cooling Systems

This section describes biocide management practices in use at steam electric facilities with recirculating cooling systems, including natural decay of TRO/FAO, dehalogenation, and detoxification of non-oxidizing biocides.

Natural Decay of TRO/FAO with No System Discharge

One way that facilities can reduce the amount of biocide discharged is to isolate (shut down) the cooling system blowdown until the biocide has naturally decayed to an acceptable level. Once the facility has confirmed that the biocide is at an acceptable level, the cooling system blowdown is reopened and discharge resumes.

Some facilities are unable to shut down their cooling system blowdown during chlorination because their cooling towers are controlled by the conductivity present in the cooling water. If during chlorination, the conductivity of the wastewater within the cooling system reaches a certain level, the cooling system will blowdown regardless [IDNR, 2006a].

UWAG also stated that while the blowdown is shut off, there is a buildup of calcium carbonate in the cooling water, which can scale and corrode the cooling tower. If calcium carbonate builds at a facility to the point that scaling and corrosion become too severe, the facility would have to take the unit off line for acid treating.

Dehalogenation

See Section 5.5.1.3 for a discussion of dehalogenation systems.

Detoxification for Non-Oxidizing Biocides

Non-oxidizing biocides control the growth of microbiological organisms differently than oxidizing biocides. Instead of oxidizing the organisms, the non-oxidizing biocides interfere with the metabolism of the organisms. After the organisms are dead, they often release hold of the condenser tubes and are washed away with the passing cooling water. Non-oxidizing biocides are mainly used in recirculating cooling systems, but can be used with once-through cooling systems to control macrobiological organisms such as Asiatic clams. Non-oxidizing biocides are typically used as a supplement to oxidizing biocides, but can be used for primary biofouling control [UWAG, 2006c].

Facilities that use non-oxidizing biocides to control biofouling need to deactivate the biocide residual prior to discharge. To detoxify the biocide, facilities typically shut down the cooling system blowdown and add bentonite clay to the system, which absorbs excess biocide in the water. The facility confirms that the biocide concentration is at an acceptable level prior to reopening the cooling system blowdown. UWAG stated that if the cooling tower blowdown is discharged to an ash pond, bentonite clay normally does not need to be added because the fly ash will absorb the residual biocide [UWAG, 2006c].

5.5.2 Zero Liquid Discharge Systems

Zero liquid discharge (ZLD) systems have been implemented at steam electric power plants to eliminate all types of process wastewaters, including cooling tower blowdown, boiler blowdown, coal pile runoff, ash pond overflow, FGD wastes, and other miscellaneous waste streams.

ZLD systems eliminate liquid waste stream discharge and recycle high-purity water for reuse in the process, thereby reducing plant water consumption by 10 to 90 percent. They are based on the use of a brine concentrator, in combination with other evaporators, spray dryers, and crystallizers.

- *Brine Concentrator* - Seeded-slurry, falling-film evaporators that convert highly saturated industrial wastewaters into distilled water for reuse. With a typical brine concentrator, 95 to 99 percent of wastewater can be recovered as high-purity distillate (<10 mg/L total dissolved solids). Brine concentrators are specific types of falling film evaporators used to treat wastewaters saturated in scaling constituents such as calcium sulfate or silica.

- *Evaporators* - Vertical-tube, falling-film evaporators that convert industrial wastewaters into distilled water for reuse in the plant. With a typical evaporator, 95 to 99 percent of wastewater can be recovered as high-purity distillate (<10 mg/L total dissolved solids).

- *Spray Dryers/Crystallizers* – Crystallizers that preconcentrate the wastewater to reduce the remaining wastewater to solids. Crystallizer systems use mechanical vapor recompression (MVR) technology to recycle the steam vapor, which is clean enough to reuse in the plant. The solid cake produced by the crystallizer is easy to handle and suitable for landfill disposal.

In the original rulemaking, EPA identified the brine concentrator (vapor-compression evaporation system) as a potential technology to recover and recycle water from the cooling tower blowdown and other low-volume waste streams. The 1974 Development Document concluded the following regarding the use of brine concentrators to control low-volume wastes[23]:

> "The application of evaporative brine concentrators to low-volume waste stream effluents after chemical treatment is not known to have been achieved. Therefore, some technical risks may be involved in applying this technology directly to low-volume wastewater of power plants." [U.S. EPA, 1974]

[23] The low-volume waste streams in the 1974 analysis include the following: boiler blowdown, demineralizer blowdown, ash sluicing water blowdown, coal pile runoff, SO_2 scrubber blowdown (i.e., FGD), treated sewage effluent, boiler cleaning waste, and cooling tower blowdown.

Since the 1974 regulation, the steam electric industry has started using this technology to control low-volume wastes, such as boiler blowdown and cooling tower blowdown.

Table 5-9 lists plants with ZLD systems in place. This list is provided to demonstrate the use of the technology in this industry. It is not intended to be an exhaustive list of U.S. facilities operating ZLD systems.

Detailed Example of a Boron Mitigation ZLD System for FGD Wastes

EPA identified a ZLD system being designed to control boron discharges from FGD scrubber blowdown from the City of Springfield's Dallman Power plant in Illinois. EPA contacted the manufacturer to obtain additional information regarding the design and implementation of this pollutant control technology. This system is designed specifically to treat the FGD scrubber blowdown from the Dallman Power Plant, which has a flow rate of approximately 120 GPM and contains 2 to 2.5 percent solids.

As described in Section 3.2.1.6, FGD is a process used to control the sulfur dioxide emissions from coal-fired power plants. A wet or dry scrubber using a sorbent, usually lime or limestone, scrubs the flue gas with the sorbent slurry and produces calcium sulfite, which is removed in the blowdown from the scrubber. In addition to boron, the scrubber blowdown contains other metals in the flue gas, such as mercury, arsenic, and selenium, which originate from the coal used to fuel the plant.

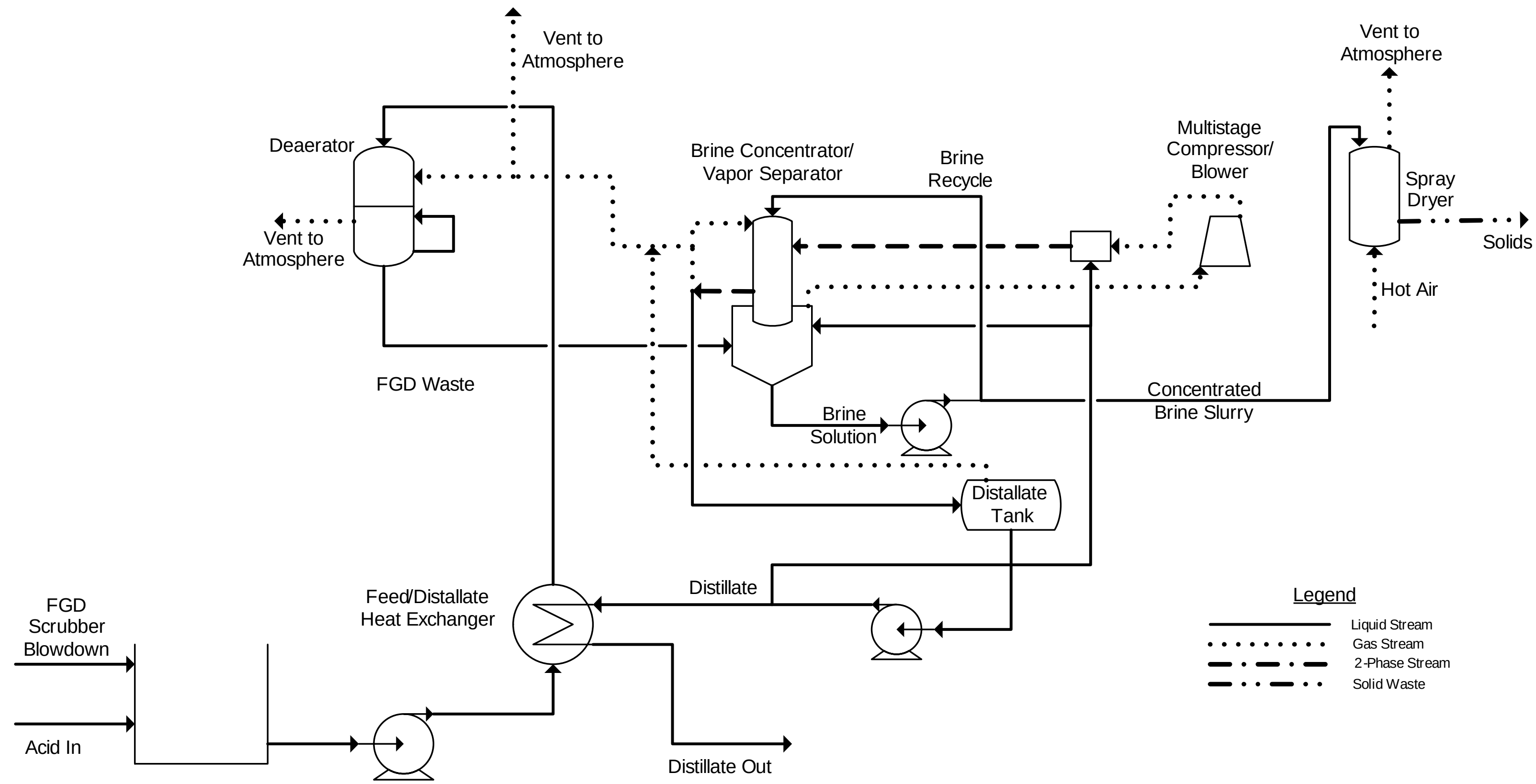
Figure 5-1 presents a process flow diagram of the ZLD boron mitigation system. The first step of this treatment system is to adjust the pH of the FGD scrubber blowdown to approximately 6.5 by adding acid to the waste stream. The facility then pumps the acidified scrubber blowdown through a heat exchanger to bring the waste stream to its boiling point. The waste stream continues to a deaerator where the noncondensable materials such as carbon dioxide and oxygen are vented to the atmosphere [Aquatech, 2006b].

From the deaerator, the waste stream enters the sump of the brine concentrator. Brine from the sump is pumped to the top of the brine concentrator and enters the heat transfer tubes. While falling down the heat transfer tubes, a portion of the solution is vaporized and then compressed and introduced to the shell side of the brine concentrator. The temperature difference between the vapor and the brine solution causes the vapor to condense as pure water. The condensed vapor (distillate) waste stream of clean water is produced at a rate of 108 GPM. The distillate is recycled to the boiler as make-up water. [Aquatech, 2006b].

Table 5-9. Steam Electric Facilities Currently Operating ZLD Systems

Plant Name	Plant Location	Plant Type	Date of Operation	Flow (GPM)	Capacity (MW)	Technologies	Types of Wastewater
Stanton Energy Center[a]	Orlando, FL		Summer 1995	600		Brine concentrator and 2 crystallizers	Cooling tower blowdown
AES Ironwood	Lebanon, PA	Gas-fired combined cycle	2001	200	700	Brine concentrator, crystallizer, RO, and EDI	Cooling tower blowdown
Cedar Bay Cogeneration Plant	Jacksonville, FL	Coal	January 1994	150	250	Brine concentrators (2) and crystallizer	Cooling tower blowdown
Gila River Power	Gila Bend, AZ	Combined cycle	2006	2,400	2,200	Pretreat with clarifiers and multimedia filtration. Brine concentrators (2) and RO (4).	Cooling tower blowdown
Texas Independent Energy Guadalupe Power Plant	Marion, TX	Combined Cycle	Aug 2003	5,600	1,000	Brine concentrator, crystallizer, and EDI	Cooling tower blowdown
Griffith Energy LLC	Kingman, AZ	Gas-fired combined cycle		230	520	HERO™ (RO) system followed by evaporation pond	Cooling tower blowdown
Arlington Valley Power	Arlington, AZ	Combined Cycle		1,675		HERO™ (RO) system followed by evaporation pond	Cooling tower blowdown
Bechtel Power Corporation	Northampton, PA	Culm	January 1995	1,000		Evaporators	Cooling tower blowdown; demineralizer waste
Panda Energy	Brandywine, MD	Gas-fired combined cycle	September 1996	280		Spray-film® evaporator	Cooling tower blowdown

Source: Aquatech, 2006a; GE, 2006.
[a]A new 285-MW IGCC plant is currently being designed for this site.
EDI – Electrodeionization.
GPM – Gallons per minute.
HERO™ – High Efficiency Reverse Osmosis.
MW – Megawatt.
RO – Reverse osmosis



Source: Aquatech, 2006b.

Figure 5-1. ZLD Boron Mitigation System for FGD Wastes

The concentrated brine slurry, approximately 20 to 25 percent solids, is again recycled with a small amount continuously withdrawn and sent to the spray dryer. Because the waste stream is 10 times more concentrated, the flow rate of the solution is 10 times less, or 12 GPM, leaving the concentrator. From the brine concentrator, the concentrated slurry is sent to a spray dryer. The slurry is fed to the top of the spray dryer and is sprayed down the shaft. Hot air is fed up through the bottom of the dryer and evaporates the remaining water in the slurry. The hot air and the evaporated water are vented to the atmosphere, while the solids fall to the bottom of the dryer for collection. The pH treatment and the precipitation of the metals during the process ensures that they will not be vented to the atmosphere with the flue gas from the spray dryer [Aquatech, 2006b].

The solids removed from the system are typically sent to a landfill. However, like fly ash, FGD waste can be recycled and used for other various applications. The FGD materials can be used in the following applications:

- Raw material for wallboard;
- Fill material for structural applications and embankments;
- Feed stock in the production of cement;
- Raw material in concrete products and grout; and
- Ingredient in waste stabilization and/or solidification [U.S. EPA, 2006h].

Although the system is referred to as a “boron mitigation system,” it can remove other metals from the waste stream. It can also be designed to treat other waste streams associated with power generation. According to the manufacturer, the reason this system was termed a “boron mitigation system” is because boron was the pollutant of most concern for this facility [Aquatech, 2006b].

The brine concentrator can achieve a concentration of only approximately 20 to 25 percent solids, so the solids present in the incoming stream limit its use; however, if the incoming waste stream is already 20 to 25 percent solids, it could be sent directly to the spray dryer. The manufacturer has already built several ZLD systems for power plants outside of the United States that control flow rates from 700 to 800 GPM [Aquatech, 2006b].

The manufacturer stated that this system could be used to treat the FGD scrubber blowdown from any power plant that uses a wet scrubber. They estimate that there are between 50 and 100 facilities in the United States that are using wet scrubbers for FGD [Aquatech, 2006b]. According to the EIA information collected in 2002, there are approximately 183 facilities that use wet scrubbers for FGD [U.S. DOE, 2002b].

6.0 ALTERNATIVE-FUELED STEAM ELECTRIC FACILITIES

This chapter describes EPA's study of alternative-fueled steam electric facilities, which produce electricity for distribution and sale using steam that is created by means other than fossil-fueled or nuclear-fueled process. In this chapter, alternative-fueled steam electric facilities refer to those facilities that produce steam by combusting a solid or gaseous alternative fuel, those that use steam from geothermal reservoirs (geothermal steam electric facilities), and those that produce steam using the sun's energy (solar steam electric facilities).

Wastewater generated by alternative-fueled steam electric processes is not currently regulated by the Steam Electric ELGs, since their electricity does not result "…primarily from a process utilizing fossil-type fuel (coal, oil, or gas) or nuclear fuel…", as defined at 40 CFR 423.10. As part of the detailed study of the steam electric industry, EPA investigated alternative-fueled steam electric facilities to determine whether a revision to the current Steam Electric ELGs may be warranted to include these types of steam electric wastewaters.

EPA reviewed NPDES permits for a prioritized subset of alternative-fueled steam electric facilities to identify sources of wastewater and determine how the wastewaters are currently regulated (e.g., whether the Steam Electric ELGs are applied using BPJ). EPA used information available from the EIA to identify steam electric facilities that reported using an alternative fuel in 2002 and identified 207 facilities. From this group, EPA selected a subset of 28 facilities that represents each reported alternative fuel type and a significant percentage of the total alternative-fueled steam electric energy capacity. After searching public web sites and contacting state permitting authorities directly, EPA acquired NPDES permits for 13 of the 28 targeted facilities.

This chapter presents EPA's findings on alternative-fueled steam electric facilities that were obtained through the NPDES permit review, which included communications with permitting authorities, and a literature search.

6.1 Alternative-Fueled Steam Electric Processes and Wastewaters

The steam electric generating process used at alternative-fueled steam electric facilities is similar to that used by all steam electric facilities, as described in Section 3.2, in the sense that they use a steam/water system as the thermodynamic medium to produce electricity. In alternative-fueled steam electric facilities, steam (which may or may not be produced in a boiler) is used to drive a steam turbine/electric generator and the steam is condensed by noncontact cooling.

The following subsections describe the steam electric process, sources of wastewater, potential wastewater pollutants, and current permitting practices for various types of alternative-fueled steam electric facilities.

6.1.1 Solid Fuels

Steam electric facilities fueled by solid alternative fuels (e.g., municipal solid waste, wood solid waste, agricultural by-products, and tires) use a similar (if not identical) process as those facilities that are currently regulated under 40 CFR Part 423. These alternative-fueled steam electric facilities combust a solid fuel, typically in a boiler, to produce steam. This combustion process generates ash. The steam produced powers a steam turbine/electric generator. The steam exiting the turbine is condensed with cooling water and the condensate is typically fed back to the boiler. Thus, steam electric facilities fueled by solid alternative fuels generate the same types of wastewaters as those currently regulated under 40 CFR Part 423. As described in Section 3.2.1, these wastewaters include fly ash and/or bottom ash sluice (slurry), metal cleaning wastes, once-through cooling water and/or recirculating cooling tower blowdown, fuel storage runoff, boiler feedwater treatment wastes, boiler blowdown, and other low-volume wastes [CEPA 2006a] [CEPA, 2006b] [U.S. DOE, 2000] [IDNR, 2006b] [Fairfax, 2006] [U.S. EPA, 2006i] [FDEP, 2006].

The following subsections describe the types of solid alternative fuels included in EPA’s study of alternative-fueled steam electric facilities.

Municipal Solid Waste

Typical constituents of municipal solid waste (MSW) include paper, paperboard, yard waste, plastics, metals, glass, food waste, wood, rubber, leather, and textiles. Refuse-derived fuel (RDF) is produced from MSW through processing steps, which involve, at minimum, coarse shredding of the MSW and magnetic separation of ferrous metals [Kirk-Othmer, 2006a].

At the time of the initial 1974 Steam Electric ELGs, EPA identified one steam electric plant in the United States as using RDF for 10 percent of its fuel [U.S. EPA, 1974]. The 1974 Development Document also stated that incinerating “garbage” produces moderate amounts of hydrogen chloride, and that EPA should continue to study the disposal of the effluents from steam electric facilities using these alternative fuels.

EPA obtained data on the pollutant concentrations found in MSW ash and coal ash. Although the compositions of these ashes vary significantly depending on the type of material that is combusted and the location that the ash is sampled, EPA noted general differences between MSW ash and coal ash. As shown in Table 6-1, MSW ash can contain significantly higher amounts of barium, cadmium, mercury, molybdenum, nickel, selenium, and zinc than coal ash.

Table 6-1. Comparison of Available Coal Ash, Municipal Solid Waste Ash, and Wood Ash Composition Data

Component	Coal Ash (ppm)	Municipal Solid Waste Ash (ppm)	Wood Ash (ppm)
Aluminum	60,000 - 157,000		
Antimony			9 - 11.58
Arsenic	10.4 - 169.6	2.9 - 50	1 - 28.5
Barium	210 - 310	79 - 2,700	130 - 527
Beryllium		ND - 2.4	ND - 2
Boron	14 - 618	24 - 174	1 - 16.9
Cadmium	7 - 10	0.18 - 100	1 - 16
Calcium	3,100 - 125,600		
Chloride			382.35 – 3,200
Chromium (III)			43
Chromium (VI)			0.7 - 4
Chromium - Total		12 - 1,500	16.8 - 33.55
Cobalt		1.7 - 91	4.6 - 20
Copper		40 - 5,900	31.3 - 176.5
Cyanide			0.08 - 6
Iron	3,000 - 163,000		
Lead		31 - 36,600	7.7 - 142.5
Magnesium	900 - 60,200	700 - 16,000	
Manganese		14 - 3,130	
Mercury	ND - 0.08	0.05 - 17.5	ND - 0.6
Molybdenum	5.6 - 39.3	2.4 - 290	3.0 - 14
Nickel	123 - 242	13 - 12,910	11 - 50
Phosphorus	300 - 2,800		
Potassium	6,500 - 31,900		23,220 - 59,918
Selenium	7.6 - 36.1	0.1 - 50	ND - 20
Silicon	302,000 - 331,000		
Silver			ND - 4
Sodium	560 - 1,200		934.25 - 3,110
Strontium		12 - 640	
Thallium			ND - 70.5
Titanium	7,700 - 11,600		
Vanadium			22 - 27
Zinc	13 - 378	92 - 46,000	130 - 886

Source: Evangelou, 1996; Otero-Rey, 2003; Narukawa, 2003; Kirk-Othmer, 2000a; CEPA, 2006b; WAI 2003.
ND - Not detected.

Wood Solid Waste

Wood wastes combusted in steam electric processes typically consist of chipped lumber and residuals from sawmills or other forest industry operations, including bark, trim ends, sawdust, and planer shavings [Kirk-Othmer, 2000a].

EPA obtained data on the pollutant concentrations found in wood ash. As described for MSW ash, EPA noted general differences between wood ash and coal ash. Wood ash generally has a lower metal content (e.g., arsenic, boron, molybdenum, nickel, and selenium) than coal ash; however, as shown in Table 6-1, wood ash often contains higher amounts of potassium and zinc, and may contain slightly higher amounts of barium, cadmium, and mercury, than coal ash.

In the 1982 Development Document, EPA acknowledged that wood, sugar cane, and other crops could be combusted in coal-type boilers and that "…the utilization of biomass materials as a heat source for steam electric generation will increase as demands are placed on the coal industry to provide cleaner fuel at low prices." [U.S. EPA, 1982] This statement implies that combusting these products result in cleaner emissions to air than those of coal combustion.

Agricultural By-Products

Typical types of agricultural by-products combusted in steam electric processes include bagasse (plant residue) from sugar-refining operations, rice hulls, orchard and vineyard prunings, cotton gin trash, and the by-products of many other food and fiber-producing operations. Agricultural wastes are relatively low in metals content, and the ash often contains a lower metals content than coal and wood ash [Kirk-Othmer, 2006a].

Tires

Scrap tires can be combusted in steam electric processes either in shredded form, which is known as tire-derived fuel, or whole tires. Scrap tires, which have a high heating value, are often used as a supplement to other fuels, such as coal or wood. Tires produce roughly the same amount of energy as oil and roughly 25 percent more energy than coal, by weight. The ash residues from tire-derived fuel may contain lower heavy metals content than some coals [U.S. EPA, 2006i].

6.1.2 Gaseous Fuels

Steam electric facilities fueled by gaseous alternative fuels (e.g., landfill gas and blast-furnace gas) use a similar (if not identical) process as those facilities that are fueled by natural gas and are currently regulated under 40 CFR Part 423. These alternative-fueled steam electric facilities combust a gaseous fuel in a boiler to produce steam; however, like the natural gas combustion process, the gaseous alternative fuel combustion process does not generate ash. The steam produced powers a steam turbine/electric generator. The steam exiting the turbine is condensed with cooling water and the condensate is typically fed back to the boiler. Thus, steam electric facilities fueled by gaseous alternative fuels generate the same types of wastewaters as those currently regulated under 40 CFR Part 423 and described in Section 3.2.1, except for fly ash and/or bottom ash sluice (slurry).

The following subsections describe the types of gaseous alternative fuels included in EPA's study of alternative-fueled steam electric facilities.

Landfill Gas

Landfill gas consists approximately 50 percent methane and 50 percent inerts, which is generated in landfills as bacteria degrade organic matter. This gas mixture can be captured and processed for use as fuel in steam electric plants. During processing, a portion of the inerts are typically removed from landfill gas, which results in a fuel with a higher heating value [U.S. EPA, 2006j] [CEC, 2006]. A steam electric plant fueled with landfill gas is similar to a steam electric plant fueled with natural gas in terms of fuel composition (natural gas and landfill gas are both comprised primarily of methane) and overall process. [PDEP, 2006]

Blast Furnace Gas

Blast furnace gas is the waste gas generated in a blast furnace when iron ore is reduced to metallic iron using coke. Blast furnace gas has a relatively low heating value because it largely comprises nitrogen, carbon monoxide, and carbon dioxide. It is often combined with natural gas for combustion in steam electric processes. All steam electric facilities that reported using blast furnace gas as a primary energy source in the 2002 EIA database reported using a fossil fuel as the secondary energy source. Blast furnace gas may be used in steam electric boilers to ensure combustion of carbon monoxide to meet emissions regulations, and to generate steam from the combustion of the blast furnace gas and/or from the waste heat from the blast furnace.

6.1.3 Geothermal

In the geothermal steam electric process, geothermal fluids (typically steam) are extracted from geothermal reservoirs and are used to power steam turbine/electric generators. No fuels are combusted to produce steam. Steam exiting the turbines is condensed with cooling water and the condensate is injected into the geothermal reservoir. Geothermal steam electric plants generate steam condensate wastewater and condenser cooling wastes (typically cooling tower blowdown) [CEPA, 2006c].

EPA addressed geothermal electric generation in developing both the 1974 and 1982 Steam Electric ELGs. The 1982 Development Document states that geothermal fluids are disposed of by reinjection to the subsurface geothermal reservoir after use [U.S. EPA, 1982]. Permit writers confirmed this statement, indicating that geothermal steam electric plants do not typically have NPDES permits because they do not discharge their wastewater to surface waters [CEPA, 2006c] [CEPA, 2006d]. These facilities inject wastewater underground into the geothermal steamfield reservoirs for two major reasons [CEPA, 2006c] [CEPA, 2006d] [U.S. DOE, 2006d]. First, injecting water into the steamfield reservoirs is required to maintain steam production [CEPA, 2006c] [U.S. DOE, 2006d]. Second, the geothermal steam condensate from the steam electric generating process contains high levels of salts and metals, specifically arsenic and boron, which would be costly to remove to meet limits for discharge to surface waters [CEPA, 2006c] [CEPA, 2006d].

If discharged to surface waters without treatment, geothermal wastewaters would significantly impact the environment due to the high salts and metals concentrations. According to the Geothermal Energy Association, the geothermal industry takes steps to prevent contaminating groundwater as geothermal condensate is piped down to geothermal reservoirs. This injection is "regulated by the EPA to coincide with the Underground Injection Control Program requirements and the BLM [Bureau of Land Management] and state well construction requirements." [GEA, 2006]

6.1.4 Solar

Solar electric generating plants concentrate sunlight onto receivers using various reflecting devices. Heat transfer fluid is heated as it flows through the receivers and is used to create steam, which, in turn, is used to create electricity in conventional steam turbine/generators. Most solar electric plants that use parabolic trough reflectors to concentrate sunlight (such as the Solar Electric Generating Stations (SEGS) plants in the Mojave Desert, CA) create cooling water, boiler blowdown, and demineralizer wastewater. These wastewaters are typically discharged to an evaporation pond [U.S. DOE, 2006b]. Many solar electric plants burn natural gas when necessary to meet electrical demands [U.S. DOE, 2006b] [Kirk-Othmer, 2000b].

According to the 1982 Development Document, all solar electric generating plants at that time were developmental; however, EPA acknowledged that more systems would be developed in the future as traditional fossil fuels were depleted [U.S. EPA, 1982].

6.1.5 Summary of NPDES Permit Review

Below is a breakout of the types of alternative fuels used by the 13 alternative fuel facilities whose NPDES permits EPA reviewed (number of permits reviewed):

- Municipal solid waste (4);
- Wood waste (4);
- Agricultural by-products (1);
- Blast furnace gas (1);
- Tires (1);
- Landfill gas (1); and
- Geothermal (1).

Based on the limited number of permits reviewed and communications with permitting authorities, 40 CFR Part 423 (i.e., 423-based) limits and other requirements do not appear to be consistently applied to wastewaters generated by alternative-fueled processes. EPA was not able to determine any trends in the regulation of wastewaters based on alternative fuel type; however, EPA was able to make some general observations about types of wastewaters and determine some general trends in the way the wastewaters are regulated.

EPA found that some of the permits reviewed contained relatively few 423-based limits. In each of these cases, the process wastewaters are not discharged to surface waters. Specific examples include geothermal electric wastewaters that are reinjected into underground geothermal reservoirs, agricultural by-product-fueled steam electric wastewaters that are discharged to percolation ponds (these are permitted via state groundwater monitoring program), and other process wastewaters from indirect dischargers.

In most cases for direct dischargers, the majority of the applicable steam electric parameters are regulated with BPJ limits. The bases used for these BPJ limits vary, and may include 40 CFR Part 423 or more stringent state water quality standards, or general permitting requirements. The basis for parameter selection is generally the state water quality standards. Specifically, for condenser cooling wastewaters of direct dischargers, chlorine discharges are limited in some fashion, but zero discharge of priority pollutants is not addressed in multiple permits.

A small portion of the permits wholly incorporated the requirements of 40 CFR Part 423. These permits are unique in that the facilities use a fossil fuel in addition to the alternative fuel to generate electricity, or the permit only specifies the use of a fossil fuel. In at least one of these cases, the fossil-fueled steam electric wastewaters have separate limits then the alternative-fueled steam electric wastewaters.

Roughly half of the permits reviewed indicated that the facility does not directly discharge all of its wastewater. For example, some wastewaters are discharged indirectly, discharged to percolation ponds, or recycled. In one case, a landfill gas-fueled steam electric facility uses water supplied by a neighboring steel plant for its boilers. The steam electric facility in turn, transfers its boiler blowdown wastewater back to the steel plant.

6.2 Demographic Data

The 2002 EIA database identifies 207 facilities that reported a NAICS code of 22 (Utilities) and the use of an alternative fuel as a primary energy source to drive a steam turbine. Some of these facilities use alternative fuels in combination with a fossil- or nuclear-type (i.e., 423-type) fuel. Three of the 207 steam electric facilities report a fossil fuel as a primary energy source, in addition to an alternative fuel. Approximately 33 percent of the 207 facilities report using both an alternative fuel and a fossil fuel to power the same generator (the fossil fuel is reported as the secondary or tertiary energy source).

The average alternative energy capacity for alternative-fueled facilities in the 2002 EIA database is less than 50 MW. Excluding geothermal steam electric facilities, the 162 alternative-fueled facilities produce less than one percent of the electricity produced by the fossil or nuclear-fueled steam electric facilities currently regulated by 40 CFR 423. EPA did not include geothermal steam electric facilities in this calculation because they are generally assumed not to discharge wastewater [CEPA, 2006c] [CEPA, 2006d] [U.S. DOE, 2006d]. Table 6-2 presents a breakdown of facility energy capacity by fuel type. See Section 3.3.2 of this report for additional detail on the demographics of the regulated steam electric industry.

EPA is not aware of any analyses demonstrating that pollutant loadings are correlated to electric power generated; however, EPA believes it is reasonable to assume that alternative-fueled facilities will produce smaller pollutant loadings than those produced by steam electric facilities with energy capacities that are one or two orders of magnitude larger.

Table 6-2. Summary of Alternative-Fueled Steam Electric Facilities, by Fuel/Energy Source Type

Fuel/Energy Source	Number of Facilities	Total Steam Turbine Capacity (MW)
Regulated Steam Electric Industry		
Fossil and Nuclear Fuel	1,157	621,799
Alternative-Fueled Steam Electric Facilities		
Municipal Solid Waste	66	2,586
Wood Solid Waste	63	1,726
Landfill Gas	11	212
Solar	9	410
Agricultural By-products	6	249
Blast-Furnace Gas	2	152
Other	1	78
Tires	2	57
Other Biomass Solids	1	18
Other Gas	1	3
Total for Alternative-Fueled Facilities (excluding Geothermal)	**162**[a]	**5,491**
Geothermal[b]	45	2,987

Source: U.S. DOE, 2002a.
[a]It is possible that some of these 162 alternative-fueled facilities may be cogeneration facilities, as discussed in Section 3.2.1.
[b]Steam electric processes using geothermal energy sources are assumed not to generate wastewater [CEPA, 2006c] [CEPA, 2006d] [U.S. DOE, 2006d].

6.3 Summary

Information obtained from EPA's NPDES permit review and literature search indicate that steam electric plants that combust an alternative fuel within a boiler utilize a similar (if not identical) process as those facilities currently regulated under 40 CFR 423 that combust a fossil fuel to generate steam. Many of these alternative-fueled plants also combust fossil fuels to generate the steam, typically within the same generating unit. This indicates a similarity between the combustion side of alternative-fueled processes and the typical regulated steam electric process. This also indicates that differences in the wastewaters, originating from the combustion side of the alternative-fueled and regulated steam electric processes, are likely due to pollutants originating from the fuel source.

Additionally, information obtained from EPA's study of alternative-fueled steam electric facilities indicates that these facilities use condenser cooling systems that are similar to those used by regulated steam electric facilities. The NPDES permit review indicates that biocides are used in these cooling systems and the direct discharges are limited by NPDES permit limits for alternative-fueled facilities; therefore, the characteristics of the cooling system wastewaters of alternative-fueled steam electric facilities are likely similar to those of regulated steam electric facilities.

Based on EPA's limited permit review, 423-based limits and other requirements do not appear to be consistently applied to wastewaters generated by alternative-fueled processes. While some of the permits reviewed for the study contained limits on the steam electric pollutants of interest, not all of the pollutants are addressed. Additional data are needed to fully characterize the pollutants/concentrations in the wastewaters from the cooling water systems and the combustion/boiler side of the steam electric process for alternative-fueled systems types to determine their similarity to fossil-fueled steam electric wastewaters, and whether there are significant concerns with their discharge.

Available data from the 2002 EIA indicate that alternative-fueled steam electric facilities are not contributing a large amount of electricity compared to the regulated steam electric industry and are not likely discharging a significant amount of wastewater to the environment. Little information has been collected, however, about the pollutants and associated concentrations in the wastewater discharged from steam electric processes using these various types of alternative fuels.

7.0 STEAM AND AIR CONDITIONING SUPPLY FACILITIES

EPA develops ELGs for specific categories of industrial dischargers (i.e., point source categories). The point source categories, which may be divided into subcategories, are generally defined by the products made or services rendered and the processes used to make these products or provide these services. As part of the 304(m) review process, EPA conducts screening-level analyses using existing environmental data in the PCS and TRI databases to investigate discharges from industrial point source categories and prioritize these categories for additional review [U.S. EPA, 2005a].

Facilities with data in PCS and TRI are identified by a four-digit SIC code; however, most point source categories are not defined by SIC code, but by a description of the wastewater pollutant generating activity. During screening-level analyses, EPA investigates SIC codes reported by facilities with discharge information in PCS and TRI and divides the SIC codes into groupings, generally according to whether the industry is already regulated by existing ELGs. One of these groupings is *Potential New Subcategories of Existing Point Source Categories*, which includes industry sectors not subject to existing ELGs. EPA then considers whether the industry's processes, operations, and wastewaters generated are such that it would be appropriately included as a new subcategory of an existing point source category.

During the 2005 screening-level review, EPA identified SIC codes 4939 and 4961 as potential new subcategories of the Steam Electric Power Generating Point Source Category at 40 CFR 423. SIC code 4939 facilities are utilities providing a combination of electrical, gas, and other services. SIC code 4961 facilities are steam and air conditioning suppliers producing and/or distributing steam and heated or cooled air for sale [U.S. EPA, 2005a].

In determining whether these two industrial sectors are appropriate subcategories to the Steam Electric Power Generating Point Source Category, EPA examined available data and information on the processes and sources of wastewater generated by the candidate sector, as well as the potential pollutants contained in those wastewaters. EPA then determined whether the characteristics of the processes and wastewater are similar enough to those of the currently regulated steam electric industry to add the industrial sector as a new subcategory to the ELGs.

Chapter 8 discusses EPA's study of the Combination Utilities, NEC sector (SIC code 4939). This chapter discusses the Steam and Air Conditioning Supply sector (SIC code 4961) and the results of EPA's examination of the processes and wastewaters that are generated by steam supply facilities.

7.1 Overview of the Steam and Air Conditioning Supply Sector

According to the 2002 Economic Census, 63 establishments are engaged in steam and air conditioning supply[24] in the United States [USCB, 2002]. Examples of facilities within the Steam and Air Conditioning Supply sector include the following:

[24] The 2002 Economic Census is based on NAICS. The NAICS code for steam and air conditioning supply (22133) corresponds directly to SIC code 4961.

- Air conditioning supply services;
- Cooled air suppliers;
- Distribution of cooled air;
- Chilled water suppliers;
- Geothermal steam production;
- Steam heating systems (suppliers of heat); and
- Steam supply systems, including geothermal.

Many of these facilities generate steam; however, this steam is not typically used to generate electricity. Thus, many steam supply facilities would be regulated by 40 CFR Part 423 if not for the language at 40 CFR 423.10 limiting the applicability to facilities “primarily engaged in the generation of electricity.”

7.2 Summary of Available Data and Information

This section summarizes data and information that were available for the Steam and Air Conditioning Supply sector during EPA’s study of this sector. EPA reviewed data for SIC code 4961 reported to PCS and TRI. To obtain additional information about electric generators the facilities in this SIC code may be operating, EPA matched these facilities to those that reported to EIA. EPA also reviewed selected NPDES permits for the steam supply facilities that were identified in PCS.

These sources provided information about potential types of wastewater generated by steam supply facilities, as well as the relative number of these facilities that are likely to generate and discharge wastewater. For those wastewater-generating steam supply facilities included in PCS, EPA examined the typical flow rates reported and wastewater parameters currently regulated for this industry.

7.2.1 Permit Compliance System

EPA extracted all data reported to PCS for facilities within SIC code 4961. Seventeen steam and air conditioning supply facilities reported to PCS in 2002 [U.S. EPA, 2006a] and only one of these facilities is classified as a major discharger. Table 7-1 summarizes these facilities along with their calculated total TWPE loads. See the *2005 Annual Screening-Level Analysis* report [U.S. EPA, 2005a] for discussion of EPA’s method of calculating TWPE. Table 7-1 also indicates whether chlorine, TRO, chlorine-produced oxidants (CPO), or metal parameters are discharged from the facility.

Table 7-1. Steam and Air Conditioning Supply Facilities Identified in 2002 PCS Database

NPDES ID	Name	City	Total Load (TWPE)[a]	Cl/TRO/CPO Reported[b]	Metals Reported
CO0039551	Pitkin Iron Corporation	Glenwood Springs	0		
CT0004014	**Hartford Steam Co.**[c,d]	**Hartford**	**2,386**	**TRO**	**Zn, Cu, Pb**
DC0000035	GSA-NCR Hotd (Central Htg Plt)	Washington	0		
IL0072320	**SIU-Carbondale**[d]	**Carbondale**	**0.323**		**Fe**
MD0061930	Trigen-Energy Baltimore	Baltimore	0		
MD0065986	Baltimore City Housing Auth.	Baltimore	0		
MD0066249	**Trigen-Baltimore Energy Corp.**[d]	**Baltimore**	**0.000514**		**Cu**
MD0066877	**Trigen-Energy Baltimore**[d]	**Baltimore**	**0.0218**	**Cl**	
NJ0109673	Central Heat Plant Bldg 2401	New Hanover Township	0	CPO	
OK0002461	**Trigen-Tulsa Energy Corp**[d]	**Tulsa**	**0.718**	**Cl**	
SC0045560	Council Energy	Orangeburg	0		
SD0025445	St Mary's Hospital	Pierre	0		
SD0025569	Haakon School District No 27-1	Philip	0		
SD0025798	St Joseph's Indian School	Chamberlin	0		
SD0026026	Edgemont, City Of - Geothermal	Edgemont	0		
TN0065447	Nashville Thermal Transfer Cor	Nashville	0		
TX0008851	Texas Medical Central	Houston	0		

Source: U.S. EPA, 2006a.
[a]EPA was able to calculate TWPE loads for five facilities reporting concentration and flow data for pollutants for which EPA has developed a TWF. Zero (0) TWPE loads indicate either the facility did not report both concentration and flow data and/or the facility reported only parameters for which EPA has not developed a TWF (e.g., TSS, BOD_5).
[b]Cl – Chlorine; TRO – Total residual oxidants; and CPO – Chlorine produced oxidants (EPA has not developed TWFs for TRO and CPO; therefore, these loads are not included in TWPE totals).
[c]This facility is a major discharger.
[d]The NPDES permits for the facilities shown in bold were reviewed by EPA for the detailed study.

While there are records in the *PCSLoads2002* database for 17 steam and air conditioning supply facilities, not all of these facilities reported both wastewater flow and pollutant concentration data. Therefore, EPA was able to calculate loads for only 14 of the 17 steam and air conditioning supply facilities reported in PCS. Table 7-2 presents the calculated pollutant loads for these 14 facilities.

Table 7-2. PCS 2002 Pollutant Loads for Steam and Air Conditioning Supply Facilities

Pollutant	Number of Facilities Reporting Load	Load (lbs/year)	TWPE (% of Total TWPE)
Copper	2	1,931	1,226 (51%)
Lead	1	503	1,127 (47%)
Zinc	1	706	33 (1.4%)
Chlorine	2	1.45	0.74 (0.03%)
Iron	1	51	0.29 (0.01%)
Sulfate	1	6,735	0.04 (0.001%)
Total Dissolved Solids	4	9,681,114	NA
Chemical Oxygen Demand	3	35,128	NA
Total Suspended Solids	11	31,477	NA
Oil and Grease	4	4,465	NA
BOD_5	3	1,919	NA
Dissolved Oxygen	1	1,402	NA
Total Residual Oxidants	1	540	NA
Chlorine Produced Oxidants	1	39	NA
Total Organic Carbon	1	36	NA
Hydrocarbons, IN H2O,IR,CC14 Ext. Chromat.	1	17	NA
Petrol Hydrocarbons, total	1	3	NA
Total	**14**	**9,766,068**	**2,387**

Source: U.S. EPA, 2006a.
NA – Not applicable. EPA has not developed TWFs for these pollutant parameters.

EPA was able to calculate TWPE loads for five of the 14 facilities, as these facilities reported flow and concentration data for pollutants for which EPA has developed TWFs. The total TWPE discharged by these five facilities is 2,387 pound equivalents (lb-eq), which is approximately 0.2 percent of the TWPE discharged by electric generating facilities within SIC codes 4911 and 4931[25]. Copper, lead, and zinc account for greater than 99 percent of the total TWPE reported by steam and air conditioning supply facilities. One company, the

[25] The total TWPE reported for the electric generating industry (i.e., facilities within SIC codes 4911 and 4931, as described in Section 5.1) was approximately 1.1 million lb-eq in 2002 [U.S. EPA, 2006a].

Hartford Steam Company, reported more than 99 percent of the total reported TWPE. As described in Section 7.2.4, this facility supplies steam and chilled water, but does not produce electricity.

According to the 2002 PCS data, 15 of the 17 steam and air conditioning supply facilities reported nonzero wastewater discharge flows that ranged between 0.2 and 20,691 million gallons per year (MGY). The facility flows averaged 1,430 MGY, which is significantly less than a typical electric generating facility[26].

The PCS data have some limitations. In particular, only the parameters regulated by the facilities' NPDES permits are reported in PCS. In addition, not all minor discharge data is reported in PCS[27]. EPA estimates that the PCS data represent approximately 27 percent of the Steam and Air Conditioning Supply sector, based on the 2002 Census data for this SIC code. Although EPA acknowledges that the PCS wastewater data are limited, this small percentage of steam and air conditioning supply facilities contained in PCS also indicates that much of this industry either does not generate wastewater or comprises minor dischargers that are not included in PCS.

7.2.2 Toxics Release Inventory

EPA extracted data reported to TRI in 2002 for all facilities within SIC code 4961. Only one steam and air conditioning supply facility reported to TRI in 2002; however, it reported no discharge of TRI chemicals to water [U.S. EPA, 2006b].

7.2.3 Energy Information Administration

As discussed in Section 3.3.2, the EIA annually collects detailed information from facilities that operate electric generators producing one MW or more of electricity. The data include facility type, generator type, fuel/energy source, and capacity; however, facilities are classified either as Utilities[28] (NAICS code 22) or within another industrial sector (i.e., industrial non-utilities; see Chapter 9).

To estimate the number of steam and air conditioning supply facilities that operate an electric generator, EPA searched the 2002 EIA database [U.S. DOE, 2002a] for each of the 17 steam and air conditioning supply facilities identified in the PCS database. By matching parent companies, facility names, and locations, EPA was able to identify 1 of the 17 PCS steam and air conditioning supply facilities within the 2002 EIA data. According to the EIA, the Hartford Steam Company, the only major discharger identified in PCS, operated a natural gas-powered steam generator in 2002; however, EPA determined that this is not the case, based on information contained in the facility's NPDES permit (Section 7.2.4 discusses this in more detail).

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[26] The average flow rate reported by the electric generating industry (i.e., facilities within SIC codes 4911 and 4931, as described in Section 5.1) was approximately 70,000 MGY [U.S. EPA, 2006a].
[27] Data for minor dischargers are reported to PCS by the permitting authorities, at their discretion.
[28] NAICS code 22 – *Utilities* is defined as establishments providing the following utility services: electric power, natural gas, steam supply, water supply, and sewerage removal. Excluded from this sector are establishments primarily engaged in waste management services [USCB, 2002].

7.2.4 NPDES Permit Review

In researching the operations, waste streams, and existing discharge requirements currently applied to steam and air conditioning supply wastewaters, EPA reviewed NPDES permits for 5 of the 17 steam and air conditioning supply facilities identified in the 2002 PCS database. These five facilities reported both flow and concentration data to PCS in 2002 (facilities are shown in bold print in Table 7-1).

All five facilities generate steam; however, none use the steam to generate electricity. Some of the facilities produce chilled water in addition to steam. The five facilities generate wastewaters that are similar to those of a steam electric utility, including boiler blowdown, coal pile runoff, and cooling tower blowdown. The cooling water waste streams and cooling tower blowdown listed in some the permits may be associated with the chilled water production process.

Some of the permits reviewed showed that 40 CFR 423 standards were used as the basis for BPJ limits, although not all of the steam electric regulated pollutants are necessarily included in the steam and air conditioning supplier permits. Only one permit includes a limitation on TRC and two permits include only monitoring requirements for either TRC or TRO.

Upon review of the permit for the Hartford Steam Company, EPA learned that, in addition to steam and chilled water production, the facility used to generate electricity with excess steam; however, the electricity generation portion of the process has been closed since 1995. The permit has retained the limits of 40 CFR 423 as the basis for the current wastewater discharge requirements. This facility continues to report significant discharges of TRO, zinc, copper, and lead in PCS. This facility also reports a total discharge flow rate that is two orders of magnitude greater than the next highest flow rate reported by another steam and air conditioning supplier, and is the same order of magnitude as the average flow rate reported by steam electric utilities within SIC codes 4911 and 4931[29].

7.3 Conclusion

The steam production processes and wastewater pollutants of steam and air conditioning suppliers are likely to be similar to those generated by the steam electric generating units regulated under 40 CFR 423; however, it appears that there are relatively few of these facilities in the United States (according to the 2002 Economic Census, there are only 63) [USCB, 2002]. In addition, it appears that the wastewater discharge rates from this industry are significantly less on average than those of electricity generators within SIC codes 4911 and 4931. EPA has not identified data demonstrating that these steam and air conditioning supply facilities are discharging significant loadings of toxic pollutants, and therefore concludes that revising the applicability of 40 CFR Part 423 to include these facilities is not warranted at this time.

[29] The average flow rate reported by the electric generating industry (i.e., facilities within SIC codes 4911 and 4931, as described in Section 5.1) was approximately 70,000 MGY [U.S. EPA, 2006a].

8.0 COMBINATION UTILITY WASTEWATERS

As described in Chapter 7, in the *2005 Screening-Level Analysis* report [U.S. EPA, 2005a], EPA reviewed discharge information reported by facilities within SIC codes 4939 and 4961 to TRI and PCS to determine if these facilities have operations and wastewater characteristics similar enough to those in the Steam Electric Power Generating Point Source Category, to consider these two industry sectors (or certain facilities within the sector) as potential new subcategories.

Chapter 7 of this report discusses EPA's study of the Steam and Air Conditioning Supply sector (SIC code 4961). This chapter describes the Combination Utilities, NEC sector (SIC code 4939) and the results of EPA's examination of the processes and wastewaters generated by steam supply facilities.

8.1 Overview of the Combination Utilities, NEC Sector

As previously described in Section 3.1.2, Combination Utilities, NEC are defined by the U.S. Census Bureau (USCB) as:

> "Establishments primarily engaged in either providing electric services in combination with other services, with electric service as the major part though less than 95 percent of the total or providing gas services in combination with other services, with gas services as the major part though less than 95 percent." [USCB, 2000]

According to the USCB's Comparative Statistics, there were 1,989 combination utilities in the United States in 1997 [USCB, 2000]; however, not all of these facilities are relevant to the detailed study. By definition, the Combination Utilities, NEC sector comprises facilities that perform services other than electric power generation, and more specifically services other than steam electric power generation.

Based on the screening-level analysis, EPA determined that the wastewaters generated by facilities classified as Combination Utilities, NEC (SIC code 4939) are not currently subject to existing ELGs; however, Combination Utilities, NEC by definition includes facilities that generate electric power, albeit in combination with providing other utility services. Because at least a portion of these facilities are expected to be *engaged in the generation of electricity for distribution and sale* [40 CFR 423.10], EPA determined that the electric generating activities performed at some combination utilities might be appropriately addressed as a new subcategory to the Steam Electric Power Generating Point Source Category. In the screening-level analysis, EPA also examined the pollutants reported in TRI and PCS to be discharged by these facilities and determined that they are similar to those discharged by the currently regulated steam electric industry [U.S. EPA, 2005a].

For these reasons, EPA included combination utilities in the detailed study to determine whether it would be appropriate to revise the scope of the Steam Electric ELGs to include such facilities.

8.2 Summary of Available Data and Information

This section summarizes data and information that were available for the Combination Utilities, NEC sector. EPA reviewed data for SIC code 4939 reported to TRI and PCS and matched applicable facilities found in these databases to those that reported to EIA to obtain additional information about electric generators they may be operating. EPA also reviewed a select number of NPDES permits for the combination utilities identified in PCS.

These sources provided information about potential types of wastewater generated by combination utilities, as well as the relative number of these facilities that are likely to discharge wastewater. For those combination utilities included in PCS that reported wastewater discharges, EPA examined the typical flow rates reported and wastewater parameters currently regulated by their NPDES permits.

8.2.1 Toxics Release Inventory

EPA extracted data reported to TRI in 2002 for all facilities within SIC code 4939. Only eight combination utilities reported to TRI, and of these, only one reported a direct release to water (barium and barium compounds with a TWPE of 0.003). The remaining seven reported no discharge of a TRI chemical to water [U.S. EPA, 2006b]. TRI does not specifically identify the process source(s) of the wastewater and pollutants discharged.

8.2.2 Permit Compliance System

EPA also extracted all data reported to PCS in 2002 for facilities within SIC code 4939. PCS contains data for 21 combination utilities, all classified as minor dischargers [U.S. EPA, 2006a]. Table 8-1 summarizes these facilities along with their total TWPE loads reported in the database. The *2005 Annual Screening-Level Analysis* report [U.S. EPA, 2005a] discusses EPA's method of calculating TWPE. Table 8-1 also indicates whether chlorine or metal parameters are monitored at the facility.

While the *PCSLoads2002* database has records for 21 combination utilities, not all of these facilities reported wastewater flow and pollutant concentration data to determine pollutant loads. EPA was able to calculate loads for 16 of the 21 combination utilities reported in PCS. Table 8-2 summarizes the total load and TWPE for each pollutant reported by these 16 combination utilities. The pollutants reported most often by these facilities were TSS, BOD_5, and ammonia.

The total TWPE discharged by these 16 facilities is approximately 1,700 lb-eq, less than 0.2 percent of the TWPE discharged by electric generating facilities within SIC codes 4911 and 4931[30]. Nearly all of the TWPE (99 percent) was reported for chlorine and nitrate discharges by four facilities.

[30] The total TWPE reported for the electric generating industry (i.e., facilities within SIC codes 4911 and 4931, as described in Section 5.1) was approximately 1.1 million lb-eq in 2002 [U.S. EPA, 2006a].

Table 8-1. Combination Utilities Identified in 2002 PCS Database

NPDES ID	Name[a]	City	Total Load[b] (TWPE)	Chlorine Reported	Metals Reported
AR0034363	***Shumaker Public Service Corporation**[c]	**East Camden**	**103**	**Cl**	**Zn**
CO0042447	***Tri-State Generation and Transmission Association**[c,d]	**Rifle**	**130**	**Cl**	**Cr-6, Fe, Zn**
CO0044580	Colorado Springs, City Of	Colorado Springs	0		
IL0042625	Lake Arispie Water Co, Inc.	Princeton	0		
IL0045527	Consumers Il Water-Candlewick	Poplar Grove	0.371		
IL0045535	***Consumers Illinois Water Company – Woodhaven Division**[c]	**Sublette**	**0.117**	**Cl**	**Fe**
IL0045543	Aqua Illinois-Woodhaven	Sublette	0.0972		
IL0048593	Otter Creek Lake Utility Stp	Davis	0.226		
IL0052817	Stonewall Utility Co Stp	Oakbrook Terrace	0.211		
IL0059072	Illinois Power-Hydrostatic	Decatur	0		
IL0059391	Cedar Bluff Utilities, Inc.	Dunlap	0.0103		
IL0070904	Lone Oak Subdivision Stp	Murphysboro	0.00859		
IL0071030	Emmett Utilities Inc. Stp	Colchester	0		
NE0124133	Sargent Underground Tank	Sargent	0		
NY0005894	**Glenwood Landing Energy Center**[c,d]	**Glenwood Landing**	**0.0175**		
NY0106259	**American Ref-Fuel Niagara Lp**[c,d]	**Niagara Falls**	**6.74**		**Al, Cr, Cu, Fe, Zn**
NY0201138	11th Street Conduit	New York	0.0588		
NY0226416	Freeport (V) Power Plant #2[d,e]	Freeport	0.00128		
NY0259055	Dte Tonawanda LLC	Buffalo	0		

Table 8-1 (Continued)

NPDES ID	Name[a]	City	Total Load[b] (TWPE)	Chlorine Reported	Metals Reported
OH0041335	***Shelly Materials, Inc. – Price Inland Terminal[c]**	**Belpre**	**0.0135**		**Mn**
TX0054038	***Matagorda Waste Disposal and Water Supply Corporation[c]**	**Matagorda**	**1,443**	**Cl**	

Source: U.S. EPA, 2006a.
[a]EPA was able to calculate TWPE loads for 14 facilities reporting concentration and flow data for pollutants for which EPA has developed a TWF. Zero (0) TWPE loads indicate that either the facility did not report both concentration and flow data and/or that the facility only reported parameters for which EPA has not developed a TWF (e.g., TSS, BOD_5).
[b]Plant names appear in the table as they do in the 2002 PCS data extraction, unless the complete name was available in the NPDES permit (see Note c).
[c]Facilities shown in bold were targeted by EPA for NPDES permit review. EPA was able to acquire and review five of these permits for the detailed study. These five permits are denoted with an asterisk (*) in the table.
[d]These combination utilities were also identified in the 2002 EIA database (refer to Table 8-3).
[e]According to the 2002 EIA data, this combination utility does not operate a steam electric generating unit; therefore, EPA did not select this facility for NPDES permit review.

Table 8-2. PCS 2002 Pollutant Loads for Combination Utilities, NEC

Pollutant	Number of Facilities	Total Load (lbs)	Total Load (TWPE)
Chlorine	4	3,027	1,541
Nitrogen, Total Nitrate (as N)	1	39,227	126
Zinc	3	148	7
Nitrogen, Ammonia	9	2,421	3
Aluminum	1	28	2
Copper	1	4	2
Chloride	1	29,839	1
Iron	3	183	1
Hexavalent Chromium	1	1	1
Sulfate	1	26,353	0.1
Chromium	1	2	0.1
Manganese	1	2	0.1
Bis(2-Ethylhexyl)phthalate	1	0.4	0.1
Hexachlorcyclopentadiene	1	0.1	0.1
Benzene	2	1	0.04
Xylene	3	3	0.01
Toluene	3	1	0.006
Ethylbenzene	2	2	0.003
Phenol and Phenolics	1	0.09	0.003
Total Dissolved Solids	1	850,993	NA
Total Suspended Solids	15	44,710	NA
BOD_5	9	18,796	NA
Dissolved Oxygen	2	16,677	NA
Oil & Grease	1	1,322	NA
Total Priority Volatiles	1	3	NA
Base/Neutral Compounds	1	3	NA
Total	**16**	**1,033,748**	**1,684**

Source: U.S. EPA, 2006a.
NA – Not applicable. EPA has not developed toxic weighting factors for these pollutant parameters.

Several pollutants that are characteristically found in steam electric process wastewaters are discussed in Section 5.2. Several of these are reported to be discharged by combination utilities, including zinc, copper, and aluminum. Chlorine, also a typical steam electric wastewater pollutant, accounts for 92 percent of the TWPE; however, it was only reported to be discharged by four facilities.

According to the 2002 PCS data, 16 of the 21 combination utilities reported non-zero wastewater discharge flows that ranged between 0.6 and 177 MGY. The facility flows averaged 51 MGY, which is significantly less than a typical electric generating facility[31].

The PCS data does have some limitations. In particular, only the parameters regulated by the facilities' NPDES permits are reported in PCS. In addition, not all minor discharge data is reported in PCS[32]. EPA estimates that only one percent of the Combination Utilities, NEC sector are represented in PCS, based on the 1997 USCB data for this SIC code. Although it is acknowledged that the PCS wastewater data are limited, this small number of combination utilities contained in PCS also indicates that much of this industry either does not generate wastewater or comprises minor dischargers that are not included in PCS.

8.2.3 Energy Information Administration

As discussed in Section 3.3.2, the EIA annually collects detailed information from facilities that operate electric generators producing one MW or more of electricity. The data include facility type, generator type, fuel/energy source, and capacity; however, facilities are classified either as Utilities[33] (NAICS code 22) or within another industrial sector (i.e., industrial non-utilities; see Chapter 9). The EIA database does not specifically identify facilities as combination utilities.

To estimate the number of combination utilities that operate an electric generator, EPA searched the 2002 EIA database [U.S. DOE, 2002a] for each of the 21 combination utilities identified in the *PCSLoads v.04* database [U.S. EPA, 2006a]. By matching parent companies, facility names, and locations, EPA was able to identify 4 of the 21 PCS combination utilities within the 2002 EIA data. Of these four combination utilities, three reported operating steam electric generators. Table 8-3 summarizes the EIA data found for these four facilities.

[31] The average flow rate reported by the electric generating industry (i.e., facilities within SIC codes 4911 and 4931, as described in Section 5.1) was approximately 70,000 MGY [U.S. EPA, 2006a].
[32] Data for minor dischargers are reported to PCS by the permitting authorities, at their discretion.
[33] NAICS code 22 – *Utilities* is defined as establishments providing the following utility services: electric power, natural gas, steam supply, water supply, and sewage removal. Excluded from this sector are establishments primarily engaged in waste management services [USCB, 2002].

Table 8-3. Summary of EIA Data for Combination Utilities

Plant Name[a]	Parent Company[a]	State	Prime Movers	Primary Fuel	Nameplate Capacity (MW)
American Ref-Fuel of Niagara [b]	**American Ref-Fuel Co.**	**New York**	**Steam turbines**	**Municipal solid waste**	**50**
Glenwood [b]	**KeySpan Generation LLC**	**New York**	**Steam turbines**	**Natural gas**	**228**
			Combustion/gas turbines	Distillate fuel oil	110
Plant No. 2	Freeport Village of Inc.	New York	Internal combustion engine	Distillate fuel oil	19.2
			Combustion/gas turbine	Distillate fuel oil	18.1
***Rifle Generating Station [b]**	**Tri-State Generation and Transmission Association, Inc.**	**Colorado**	**Combined cycle system**	**Natural gas**	**108.3 (39 MW from the steam turbine)**

Source: U.S. DOE, 2002a.
[a]Plant and parent company names appear in the table as they do in the 2002 EIA database, unless the complete name was available in the NPDES permit (see Note b).
[b]Facilities shown in bold were among those targeted by EPA for NPDES permit review (see also Table 8-1). EPA was able to acquire and review one of these permits for the detailed study, which is denoted with an asterisk (*) in the table.

8.2.4 NPDES Permit Review

In researching the operations, waste streams, and existing discharge requirements currently applied to combination utility wastewaters, EPA reviewed NPDES permits for a select number of the 21 combination utilities identified in the 2002 PCS database.

Since the Combination Utilities, NEC sector includes facilities engaged in operations and services other than electric power generation, EPA targeted the permit review on combination utilities that were most likely to be generating electricity, based on available EIA data and the pollutants reported to be discharged. EPA initially identified 7 of the 21 combination utilities for NPDES permit review:

1. The three fossil-fuel driven steam electric facilities identified in the 2002 EIA database;

2. Three facilities having the highest total TWPE (each greater than 100 TWPE); and

3. One additional facility that reported monitoring data for a metal (manganese).

These seven facilities are shown in bold print in Tables 8-1 and 8-3.

After searching public web sites and contacting state permitting authorities directly, EPA acquired NPDES permits for five of the seven targeted facilities.

EPA found through the permit review that only one of the five combination utilities is an electric generating facility. The Tri-State Generating and Transmission Association, Inc. facility in Rifle, Colorado operates a natural gas-powered CCS with a steam generator capacity of 39 MW. According to the 2003 Summary of Rationale for the permit, the Rifle facility is an electric peaking power generation plant categorized by the permitter to be within SIC code 4911 – Electric Services. Until 2002, the facility was operated in conjunction with a large greenhouse that utilized steam heat provided by the facility. The facility still provides steam heat to the greenhouse; however, the peaking plant and greenhouse are currently under separate ownership [CDPHE, 2003].

The NPDES permit for this facility also indicated that the cooling tower blowdown contributes 50 to 70 percent of the total discharge, which is intermittent due to the sporadic demand for electric power from this peaking facility. The wastewater discharged by this facility is currently limited by the requirements of the Steam Electric ELGs[34], since it meets the applicability at 40 CFR 423.10 [CDPHE, 2003].

EPA found the remaining four facilities to be wastewater treatment and water supply plants. None of these facilities reported an electric generating unit to the EIA. In addition, the limited amount of information on the waste streams provided in the permits

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[34] The permit did not address limitations on copper and iron discharged with chemical metal cleaning wastewaters.

indicated they had little in common with the waste streams expected from a steam electric generating facility, as previously described in Section 3.2. Since these facilities do not appear to be "…primarily engaged in the generation of electricity for distribution and sale…" [40 CFR 423.10], they do not meet the current applicability of the Steam Electric ELGs. Further, the processes and wastewaters generated by these non-electric-generating facilities are not similar to those of the regulated steam electric industry.

8.3 Conclusion

Based on the USCB's description of the Combination Utilities, NEC industrial sector and available information about the wastewater discharged by these facilities, EPA concludes that the Combination Utilities, NEC sector, as defined by SIC code 4939, is not an appropriate subcategory for the current Steam Electric Power Generating Point Source Category.

EPA's review of NPDES permits for a select number of facilities classified within the Combination Utilities, NEC sector in PCS revealed that wastewater-generating activities performed at these facilities may be classified within other existing SIC codes, including Electric Services, Sewerage Systems, and Water Supply. Except for one facility that was primarily a steam electric facility, the permits did not indicate that the PCS combination utilities produce electricity, even as an auxiliary activity. Though EPA did not find an example in the permits reviewed, it is possible that a combination utility could operate a steam electric generating unit in addition to performing its primary activity.

EPA also determined that this industrial sector does not generate a large volume of wastewater. This estimate is based on the small number of combination utilities that report wastewater discharges included in PCS. The wastewater discharge flow rates reported to PCS from combination utilities are three orders of magnitude lower on average than those reported by electric generating facilities within SIC codes 4911 and 4931, and the total pollutant load discharged by combination utilities is a very small fraction of the load discharged by electric generators.

9.0 INDUSTRIAL NON-UTILITIES

This chapter describes EPA's review of steam electric generators located at facilities within various industrial sectors to produce electricity and/or thermal output primarily to support the activities performed at the facility. These *industrial non-utilities* include cogenerators[35], small power plants, and other non-utility generators, and do not generally produce electric power for distribution and sale.

As part of the detailed study of the steam electric industry, EPA investigated industrial non-utilities to determine whether a revision to the current Steam Electric ELGs to include these types of steam electric wastewaters may be warranted.

This chapter presents EPA's findings to date obtained through available sources of information on industrial non-utility processes and wastewaters, including available demographic and wastewater characterization data and wastewater discharge permits for industrial facilities operating a steam electric non-utility on site.

9.1 Overview of Industrial Non-Utilities

The steam electric generating process used at industrial non-utilities is similar to that used by all steam electric facilities, as described in Section 3.2. A boiler or HRSG is used to generate steam that is in turn used (at least in part) to drive an electric generator or turbine. Finally, the steam is condensed through noncontact cooling before it is returned to the boiler. Since the processes are similar, EPA expects that industrial non-utilities generate wastewater from the same sources as do regulated steam electric facilities.

One key factor that differentiates industrial non-utilities from regulated steam electric facilities is they do not produce electricity primarily for distribution and sale. EPA conducted this review because, given the processes involved in these operations, many industrial non-utilities would be regulated by the Steam Electric ELGs except for the language at 40 CFR 423.10 limiting the applicability to facilities "…primarily engaged in the generation of electricity <u>for distribution and sale</u>…" With the exception of certain instances (e.g., certain subcategories of the Pulp, Paper and Paperboard ELGs; see 40 CFR 430.01(m)), industrial non-utilities are not directly regulated by ELGs.

EPA identified industrial non-utilities for this detailed study through data collected in 2002 by the EIA. Industrial facilities that operate an electric power generator having at least one MW of capacity report to the EIA each year. Included in these data is the facility's primary NAICS code. EPA identified industrial non-utilities in the 2002 EIA data as those reporting NAICS codes *other* than 22 – Utilities (as described previously in Section 3.3.2).

EPA examined the 2002 EIA data to determine the relative size of industrial non-utilities, as well as the types of fuels used by industrial non-utilities to generate the steam. These data are described in Section 9.1.1. EPA also performed a more detailed analysis of the EIA data for the subset of industrial non-utilities that utilize fossil fuels to power a steam generator.

[35] A *cogenerator* is defined as "a generating facility that produces electricity and another form of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes" [U.S. DOE, 2006a].

Section 2.9 presents a more detailed summary of the available demographic data for fossil-fueled, steam electric industrial non-utilities.

9.1.1 Relative Size of Industrial Non-Utilities

According to the 2002 EIA data, there are 908 industrial non-utilities, most of which (nearly 80 percent) produce a relatively low amount of electric power (no more than 50 MW) [U.S. DOE, 2002a]. These 908 industrial non-utilities include facilities operating both steam and non-steam generating units (e.g., stand-alone combustion turbines, internal combustion engines, and hydraulic turbines) powered by either fossil or non-fossil fuel types. No nuclear-powered industrial non-utilities were reported to EIA in 2002.

To compare, only 11 percent of regulated steam electric facilities produce less than 50 MW of electricity. In fact, nearly half of the regulated steam electric industry comprises facilities that generate more than 500 MW of electric power [U.S. DOE, 2002a]. Section 3.3.2 contains additional information on the regulated steam electric industry.

9.1.2 Fuels Used by Industrial Non-Utilities

Industrial non-utilities may be fueled either by a fossil fuel (e.g., coal, oil, or natural gas) or an alternative, non-fossil fuel often derived from a by-product of the primary industrial process. These non-utilities may also utilize a combination of fossil and non-fossil fuels to power the steam electric generating unit. No industrial non-utilities were found to use nuclear fuels [U.S. DOE, 2002a].

The following non-fossil fuels were reported to the EIA by industrial non-utilities as the primary fuel for the steam electric generating unit (abbreviations used by EIA are presented in parentheses):

- Agricultural Crop Byproducts, Straw, Energy Crops (AB);
- Municipal Solid Waste (MSW);
- Wood and Wood Waste Solids (e.g., paper pellets, railroad ties, utility poles, wood chips) (WDS);
- Other Biomass Solids (e.g., animal manure and waste, solid byproducts) (OBS);
- Black Liquor (BLQ);
- Wood Waste Liquids (e.g., red liquor, sludge wood, spent sulfite liquor) (WDL);
- Blast Furnace Gas (BFG);
- Purchased Steam (PS);

- Other Biomass Gases (e.g., digester gas, methane) (OBG);
- Other Gas (e.g., butane, coal processes, coke-oven, refinery) (OG); and
- Other Fuels (e.g., batteries, chemicals, coke breeze, hydrogen, pitch, sulfur, tar coal) (OTH).

In 2002, 193 steam electric industrial non-utilities reported using at least one of these alternative fuel types. Among these non-fossil fuel types, BLQ and WDS were the most prevalently used primary fuels for steam electric power generation by industrial non-utilities [U.S. DOE, 2002].

As previously mentioned, it is not uncommon for an industrial non-utility to use more than one type of fuel; in fact, these facilities often will use a combination of fossil and non-fossil fuels to power the same steam electric generating unit. For example, several industrial non-utilities that reported using natural gas as the primary fuel also reported using BLQ and OG as alternates, as did several coal-burning industrial non-utilities. In addition, several of the 193 primarily non-fossil-fueled industrial non-utilities reported using coal, oil, or natural gas as alternate fuels for the steam electric generating unit [U.S. DOE, 2002].

9.2 Demographic Data for Fossil-Fueled Industrial Non-Utilities

This section describes the demographic data available from EIA for fossil-fueled, steam electric industrial non-utilities, including the specific industries represented in the data, the steam electric power generating capacities, the types of prime movers used, and the fossil fuels used by each.

EPA identified industrial non-utilities through data collected in 2002 by EIA for facilities reporting a primary NAICS code *other* than 22 – Utilities. Similar to the analysis of the regulated steam electric industry described in Section 3.3.2, EPA used the NAICS code, prime mover, and energy source information reported in Form EIA-860 to develop a demographic profile for steam electric industrial non-utilities. EPA identified the subset of industrial non-utilities in the EIA database that are *steam electric* as those operating at least one prime mover that utilizes steam, produced by burning a fossil fuel, to generate electricity.

Using the criteria for the prime mover type and fossil fuel described above for facilities reporting a primary purpose/NAICS code other than 22, EPA estimates that 314 fossil-fueled, steam-electric, industrial non-utilities reported to the EIA in 2002. These facilities are estimated to operate 683 stand-alone steam generators or CCSs[36], which have a total steam turbine capacity of 10,879 MWs[37] [U.S. DOE, 2002a]. This industrial non-utility steam turbine

[36] Refer to Section 3.2.2 for a description of the combined cycle system of electric power generation.
[37] The EIA database contains 312 facilities reporting a total of 681 steam electric units, and an additional 2 facilities reporting at least one CCS combustion/gas turbine only (one each in the chemical manufacturing and petroleum and coal products manufacturing industries). EPA assumes these additional two facilities are each operating a single steam turbine as part of their CCS, even though it was not reported to EIA. The total steam turbine capacity does not include the unknown capacities for the two CCS steam electric turbines that are assumed in the total number of facilities and generating units.

capacity is less than two percent[38] of the electricity produced by the regulated steam electric industry.

Table 9-1 summarizes the industries that reported industrial non-utilities to the EIA in 2002, the number of facilities, and the number of fossil fuel-burning steam electric generating units. The top five industries reporting operation of non-utilities, by steam electric capacity include:

- Chemical Manufacturing;
- Paper Manufacturing;
- Primary Metal Manufacturing;
- Food Manufacturing; and
- Petroleum and Coal Products Manufacturing [U.S. DOE, 2002a].

The top five industries comprise an estimated 222 non-utilities operating 481 steam generating units and producing 9,235 MW of steam electric power (85 percent of the steam electric capacity of all fossil-fueled, steam-electric industrial non-utilities reported to EIA) [U.S. DOE, 2002a]. The remainder of this section presents more detailed demographic information for these five industries.

9.2.1 Prime Movers/Generating Units

Table 9-2 shows the distribution of the types of steam electric prime movers used by industrial non-utilities within each of the top five industries. The table presents the numbers of facilities and generating units, and capacities for each type of steam electric prime mover. Based on the 2002 EIA data, industrial non-utilities generate most of their electricity (71 percent) through stand-alone steam turbines, which is also the most prevalent type of steam electric prime mover used by the regulated steam electric industry, as discussed in Section 3.3.2.

One exception to this among the top five industries is the petroleum and coal products manufacturing industry, which reported operating more CCSs than stand-alone steam turbines in 2002 [U.S. DOE, 2002a]. Comments received from the American Petroleum Institute (API) indicate that most petroleum refineries utilize natural gas or residual gases from the refinery process to power a gas/combustion turbine, the waste heat of which is used to produce steam either to generate additional electric power or to be used directly within the refining process [API, 2005]. According to API's description of petroleum refinery non-utilities, not only are these facilities using CCSs, but that they are also considered to be cogenerators (i.e., steam is produced both to power a generator and to use in other operations).

[38] EPA estimates that the total steam electric generating capacity of the regulated steam electric industry in 2002 was 621,799 MW (refer to Section 3.3.2) [U.S. DOE, 2002a].

Table 9-1. Summary of Fossil-Fueled, Steam Electric Industrial Non-Utilities, by NAICS Code

NAICS Code - Description	Number of Facilities	Number of Generating Units	Total Steam Turbine Capacity (MW)
325 – Chemical Manufacturing	59	144	3,147
322 – Paper Manufacturing	84	177	3,125
331 – Primary Metal Manufacturing	12	26	1,158
311 – Food Manufacturing	44	92	1,001
324 – Petroleum and Coal Products Manufacturing	23	42	804
Total for Top 5 Industries, by Capacity	**222 (71%)**	**481 (70%)**	**9,235 (85%)**
611 – Educational Services	33	70	456
3345 – Navigational, Measuring, Electromedical, and Control Instruments Manufacturing	1	12	205
4911 – Postal Service	1	1	178
221 – Utilities	3	5	114
3122 – Tobacco Manufacturing	3	5	101
336 – Transportation Equipment Manufacturing	3	7	92
314 – Textile Product Mills	5	14	84
327 – Nonmetalic Mineral Product Manufacturing	3	9	77
212 – Mining (except Oil and Gas)	2	5	66
622 – Hospitals	9	17	60
92 – Public Administration	5	11	57
326 – Plastics and Rubber Products Manufacturing	1	4	40
211 – Oil and Gas Extraction	10	20	34
333 – Machinery Manufacturing	2	7	24
521 – Monetary Authorities – Central Bank	1	2	12
332 – Fabricated Metal Product Manufacturing	1	2	10
321 – Wood Product Manufacturing	2	2	9
481 – Air Transportation	1	1	8
814 – Private Households	1	1	6
482 – Rail Transportation	1	2	4
561 – Administrative and Support Services	1	1	2
624 – Social Assistance	1	2	2
514 – Information Services and Data Processing Services	1	1	1
562212 – Solid Waste Landfill	1	1	1
Total	**314 (100%)**	**683 (100%)**	**10,879 (100%)**

Source: U.S. DOE, 2002a.

Table 9-2. Distribution of Prime Mover Types Among Fossil-Fueled, Steam Electric Industrial Non-utilities

Steam Electric Prime Mover	Number of Facilities[a]	Number of Generating Units	Total Steam Turbine Capacity (MW)
All Industrial Non-utilities			
Stand-Alone Steam Turbine	256 (82%)	585 (86%)	7,832 (72%)
CCS	61 (19%)	98 (14%)	3,046 (28%)
Total	**314**	**683**	**10,879**
NAICS 325 – Chemical Manufacturing			
Stand-Alone Steam Turbine	39	100	1,093
CCS	20	44	2,054
Total	**59**	**144**	**3,147**
NAICS 322 – Paper Manufacturing			
Stand-Alone Steam Turbine	81	172	3,054
CCS	4	5	71
Total	**84**	**177**	**3,125**
NAICS 331 – Primary Metal Manufacturing			
Stand-Alone Steam Turbine	12	26	1,158
CCS	0	0	0
Total	**12**	**26**	**1,158**
NAICS 311 – Food Manufacturing			
Stand-Alone Steam Turbine	41	88	976
CCS	4	4	25
Total	**44**	**92**	**1,001**
NAICS 324 – Petroleum and Coal Products Manufacturing			
Stand-Alone Steam Turbine	11	21	352
CCS	12	21	452
Total	**23**	**42**	**804**

Source: U.S. DOE, 2002a.
[a]Because a single facility may operate multiple generating units of various types, the number of facilities by prime mover type is not additive. The totals reflect the number of industrial non-utilities that are operating at least one steam electric generating unit powered by a fossil fuel.

9.2.2 Fossil Fuel Types

Table 9-3 shows the distribution of the fossil fuels used by industrial non-utilities by capacity, and specifically broken out for the top five industries. The 2002 EIA data demonstrate that fossil-fueled industrial non-utilities generally use either coal or natural gas to fuel their steam electric generators; however, some industries tend to favor a particular type of fossil fuel. For example, most primary metal manufacturing and food manufacturing non-utilities reported using coal, while most chemical manufacturing and petroleum/coal products manufacturing non-utilities reported using natural gas [U.S. DOE, 2002a]. These trends coincide with the predominant types of generators used in these industries (i.e., nearly all CCSs are powered by natural gas).

9.3 Wastewater Characterization

EPA examined pollutant load data available in the *PCSLoads2002* database [U.S. EPA, 2006a] for the industrial facilities identified in the EIA database as operating a fossil-fueled, steam electric non-utility. Out of the 314 EIA industrial non-utilities, EPA identified PCS records for 67 major dischargers and 14 minor dischargers that reported wastewater flow and pollutant concentration data, such that pollutant loads could be determined[39].

It should be noted that the industry-specific pollutant loads presented in this section represent the subset of facilities within the industry that were identified as operating a fossil-fueled, steam electric non-utility at their site. Table 9-4 summarizes the number of industrial facilities identified as operating a fossil-fueled, steam electric non-utility and that provided pollutant load information to PCS.

EPA analyzed the PCS pollutant load data reported by the 81 industrial facilities operating fossil-fueled steam electric generating unit(s) on site. Table 9-5 summarizes the top 20 pollutants discharged, based on the TWPE loads for the 81 industrial facilities, along with the number of facilities for which the load was calculated. The PCS data does have some limitations; in particular, only the parameters regulated by the facilities' NPDES permits are reported in PCS.

Since the industrial facilities' primary purpose of operation is other than electricity production, it is likely that many of the chemicals listed in Table 9-5 are not associated with electricity production.

[39] For more information on how pollutant loads were calculated using the 2002 PCS data, refer to Chapter 2 of the *2002 Screening-Level Analysis* report [U.S. EPA, 2005a].

Table 9-3. Distribution of Fuel Types Among Fossil-Fueled, Steam Electric Industrial Non-utilities

Fossil Fuel[a]	**Number of Facilities[b]**	**Number of Generating Units**	**Total Steam Turbine Capacity (MW)[c]**
All Industrial Non-utilities			
Coal:	***119 (38%)***	***308 (45%)***	***4,744 (44%)***
Anthracite Coal, Bituminous Coal (BIT)	101	269	3,956
Subbituminous Coal (SUB)	17	36	425
Lignite Coal (LIG)	1	3	363
Petroleum Coke (PC)	***4 (1%)***	***5 (1%)***	***218 (2%)***
Oil:	***25 (8%)***	***44 (6%)***	***320 (3%)***
Residual Fuel Oil (RFO)	17	32	284
Distillate Fuel Oil (DFO)	7	11	28
Waste/Other Oil (WO)	1	1	8
Natural Gas (NG)	***170 (54%)***	***324 (47%)***	***5,597 (51%)***
Total	**314**	**683**	**10,879**
NAICS 325 – Chemical Manufacturing			
Coal (BIT and SUB)	12	48	512
Oil (DFO and WO)	2	3	12
Natural Gas (NG)	44	92	2,623
Total	**59**	**144**	**3,147**
NAICS 322 – Paper Manufacturing			
Coal (BIT and SUB)	34	85	1,540
Petroleum Coke (PC)	2	3	157
Oil (DFO and RFO)	9	14	194
Natural Gas (NG)	41	75	1,234
Total	**84**	**177**	**3,125**
NAICS 331 – Primary Metal Manufacturing			
Coal (BIT and LIG)	7	14	900
Oil	0	0	0
Natural Gas (NG)	5	12	258
Total	**12**	**26**	**1,158**

Table 9-3 (Continued)

Fossil Fuel[a]	**Number of Facilities**[b]	**Number of Generating Units**	**Total Steam Turbine Capacity (MW)**[c]
NAICS 311- Food Manufacturing			
Coal (BIT and SUB)	29	63	888
Oil (DFO and RFO)	2	3	12
Natural Gas (NG)	14	26	101
Total	**44**	**92**	**1,001**
NAICS 324 – Petroleum and Coal Products Manufacturing			
Coal	0	0	0
Petroleum Coke (PC)	2	2	61
Oil (DFO)	1	3	2
Natural Gas (NG)	19	36	740
Total	**23**	**42**	**804**

Source: U.S. DOE, 2002a.
[a]No steam electric generating units were reported to use jet fuel, kerosene, or waste/other coal, or nuclear fuel in the 2002 EIA database.
[b]Because a single facility may operate multiple generating units utilizing differing fuel types, the number of facilities by fuel type is not additive. EPA estimates there are 314 industrial non-utilities operating at least one steam electric generating unit powered by a fossil fuel.
[c]The total steam electric capacity shown does not equal the sum of the steam electric capacities for each fuel type due to rounding errors.

Table 9-4. Fossil-Fueled, Steam Electric Industrial Non-Utilities Identified in PCS

Facility Type[a]	Major Dischargers	Minor Dischargers	Total Number of Industrial Non-Utilities in PCS (% of EIA facilities)
NAICS 325 – Chemical Manufacturing (59 industrial non-utilities in EIA)			
Organic Chemicals, Plastics & Synthetic Fibers (OCPSF)	6	1	7
Chlorine and Chlorinated-Hydrocarbon Manufacturing (CCH)	5	0	5
Pharmaceutical Manufacturing	2	0	2
Explosives Manufacturing	1	0	1
Inorganic Chemicals Manufacturing	1	0	1
Total	**15**	**1**	**16 (27%)**
NAICS 322 – Paper Manufacturing (84 industrial non-utilities in EIA)			
Pulp, Paper and Paperboard (Pulp & Paper)	19	3	22
Total	**19**	**3**	**22 (26%)**
NAICS 331 – Primary Metal Manufacturing (12 industrial non-utilities in EIA)			
Iron and Steel Manufacturing	5	0	5
Nonferrous Metals Manufacturing	2	0	2
Ferroalloy Manufacturing	1	0	1
Total	**8**	**0**	**8 (67%)**
NAICS 311 – Food Manufacturing (44 industrial non-utilities in EIA)			
Sugar Processing	9	1	10
Grain Mills	2	2	4
Canned and Preserved Fruits and Vegetables Processing	1	0	1
Miscellaneous Foods and Beverages	0	1	1
Total	**12**	**4**	**16 (36%)**
NAICS 324 – Petroleum and Coal Products Manufacturing (23 industrial non-utilities in EIA)			
Petroleum Refining	9	0	9
Total	**9**	**0**	**9 (39%)**
Remaining Industrial Facility Types in PCS			
Metal Finishing	2	2	4
Educational Services	0	3	3
Cement Manufacturing	1	0	1
Ore Mining and Dressing	1	0	1
Rubber Manufacturing	0	1	1
Total	**67**	**14**	**81 (26%)**

Source: U.S. EPA, 2006a.
[a]The facility types listed in this table are covered by existing point source categories, as well as other industry groupings identified during the 2005 screening-level analysis [U.S. EPA, 2005a].

Table 9-5. Top 20 Pollutants Released from Industrial Facilities Operating a Fossil-Fueled, Steam Electric Non-Utility

Pollutant	Number of Facilities Reporting	Total Load (pounds)	Total Load (TWPE)	Percentage of Total TWPE
Polychlorinated Biphenyls[a]	1	25	845,395	66%
Molybdenum	1	717,011	144,434	11%
Sulfide	9	45,441	127,300	10%
Chlorine	24	105,729	53,833	4%
Lead	19	14,084	31,548	2%
Fluoride	3	358,547	12,549	1%
Silver	2	761	12,538	1%
Aluminum	6	170,484	11,029	0.9%
Copper	24	9,031	5,733	0.4%
Mercury	5	45	5,238	0.4%
Hexachlorobenzene	2	2	4,441	0.3%
Cyanide	10	3,531	3,944	0.3%
Zinc	21	66,075	3,098	0.2%
Chloride	6	126,159,200	3,072	0.2%
Nitrogen, Ammonia	38	1,568,672	2,361	0.2%
Nickel	15	13,964	1,521	0.1%
Nitrogen, Total Nitrite (as N)	1	3,822	1,427	0.1%
Selenium	3	937	1,051	0.08%
Hexavalent Chromium	6	1,419	733	0.06%
Boron	1	3,837	680	0.05%
Total	**81**		**1,276,340**	**100%**

Source: U.S. EPA, 2006a.
[a]The polychlorinated biphenyl load shown above was reported to be discharged from a single metal finishing facility, also found to operate a steam electric generator.

In Chapter 5 of this report, EPA discussed 11 pollutants discharged by steam electric facilities that were identified either as among the top five discharged by the steam electric industry by TWPE or through specific comments provided for consideration by the study. Seven of these 11 pollutants of interest are among the top 20 discharged by the 81 industrial facilities operating a fossil-fueled, steam electric non-utility, including:

- Chlorine;
- Aluminum;
- Copper;
- Mercury;
- Zinc;
- Nickel; and
- Boron.

Again, the PCS data present only those pollutants for which the facilities are required by their NPDES permits to report. Four pollutants that were reported most frequently are chlorine, copper, zinc, and nickel; however, these were only reported by between 19 and 30 percent of the 81 industrial facilities. Only between one and six of the 81 industrial facilities reported aluminum, mercury, and boron loads. These seven "steam electric" pollutants account for less than six percent of the total TWPE reported by the 81 industrial facilities.

Table 9-6 summarizes the top 10 pollutant TWPE loads discharged by facilities within the industries identified in Section 9.2 as generating the most electricity from fossil-fueled, steam electric non-utilities operated on site. Again, while many of the industrial facilities discharge pollutants characteristically found in fossil-fueled steam electric process wastewaters, these facilities discharge many other types of pollutants that likely originate from the primary industrial processes performed at these facilities. The specific sources of wastewater pollutants within the various facility processes (e.g., the pollutants and associated loads specifically originating from the steam electric non-utility) cannot be determined from the PCS data.

Chlorine, commonly used as a biocide in steam electric cooling water systems, was reported by 24 of the 81 industrial facilities, with a TWPE of nearly 54,000 pound-equivalents (lb-eq). Four out of the five industries shown in Table 9-6 reported chlorine with the second highest TWPE among the reported discharges within each industry; however, EPA expects chlorine to also be used in the primary processes performed by these industries, and thus present in significant amounts in the process wastewaters. For example, the chemical manufacturing facilities reporting chlorine included the following types of facilities:

- OCPSF manufacturers;
- Pharmaceutical manufacturers;
- Chlorine and chlorinated-hydrocarbon manufacturers; and
- Explosives manufacturers.

EPA makes similar conclusions about the other three industries reporting high chlorine loads: Paper Manufacturing; Primary Metal Manufacturing; and Food Manufacturing.

Table 9-6. Top Pollutants Discharged by Industries Operating Fossil-Fueled Steam Electric Non-Utilities

Pollutant	Number of Facilities Reporting the Pollutant	Total Load (pounds)	TWPE (lb-eq)	Percentage of Total TWPE
NAICS 325 – Chemical Manufacturing				
Sulfide	1	33,546	93,978	65%
Chlorine	9	50,007	25,462	18%
Mercury	1	38	4,476	3%
Hexachlorobenzene	2	2	4,441	3%
Copper	10	5,524	3,507	2%
Chloride	2	120,117,637	2,925	2%
Lead	7	1,012	2,267	2%
Cyanide	4	1,589	1,775	1%
Nickel	9	13,273	1,446	1%
Nitrogen, Total Nitrite (as N)	1	3,822	1,427	1%
Total	**16**		**144,239**	**100%**
NAICS 322 – Paper Manufacturing				
Aluminum	2	143,246	9,267	45%
Chlorine	6	16,670	8,488	42%
Zinc	5	19,076	894	4%
Nitrogen, Ammonia	9	409,739	617	3%
2,3,7,8-Tetrachlorodibenzofuran (TCDF)	1	$1x10^{-5}$	552	3%
Copper	5	407	258	1%
Cyanide	1	229	256	1%
Manganese	2	4,014	58	0.3%
Nickel	2	218	24	0.1%
Ammonia	2	9,461	14	0.1%
Total	**22**		**20,475**	**100%**

Table 9-6 (Continued)

Pollutant	Number of Facilities Reporting the Pollutant	Total Load (pounds)	TWPE (lb-eq)	Percentage of Total TWPE
NAICS 331 – Primary Metal Manufacturing				
Lead	6	11,839	26,520	46%
Chlorine	2	26,896	13,694	24%
Fluoride	2	277,220	9,703	17%
Cyanide	4	1,704	1,903	3%
Zinc	5	35,518	1,665	3%
Copper	3	2,218	1,408	2%
Aluminum	2	21,042	1,361	2%
Arsenic	2	102	411	0.7%
Cadmium	2	18	408	0.7%
Benzo(a)pyrene	2	3	317	0.5%
Total	**8**		**57,964**	**100%**
NAICS 311 – Food Manufacturing				
Sulfide	2	5,392	15,105	68.1%
Chlorine	4	11,884	6,051	27.3%
Magnesium	3	554,115	480	2.2%
Nitrogen, Ammonia	8	227,163	342	1.5%
Total Potassium (as K)	1	86,116	91	0.4%
Chloride	3	2,095,519	51	0.2%
Calcium	3	1,071,349	30	0.1%
Sodium	3	4,173,146	23	0.1%
Sulfate	1	159,014	1	0.004%
Ammonia	1	42	0.1	0.0003%
Total	**16**		**22,173**	**100%**

Table 9-6 (Continued)

Pollutant	Number of Facilities Reporting the Pollutant	Total Load (pounds)	TWPE (lb-eq)	Percentage of Total TWPE
NAICS 324 – Petroleum and Coal Products Manufacturing				
Sulfide	6	6,503	18,217	53%
Silver	1	752	12,392	36%
Selenium	1	929	1,042	3%
Mercury	1	6	738	2%
Nitrogen, Ammonia	9	422,355	636	2%
Lead	1	203	455	1%
Copper	2	323	205	0.6%
Chromium	6	2,012	152	0.4%
Chloride	1	3,946,043	96	0.3%
Phenol and phenolics	7	2,824	79	0.2%
Total	**9**		**34,085**	**100%**

Source: U.S. EPA, 2006s.

Besides the uncertainty of the specific process sources of chlorine and other pollutants reported in PCS, EPA notes that there are other confounding factors that preclude a direct comparison of the industrial non-utility chlorine discharges to those of the steam electric industry. Based on data provided by the steam electric industry, EPA substantially revised downward the chlorine discharge estimates for steam electric facilities to reflect that not all steam electric facilities chlorinate their cooling water systems, and those that do chlorinate are limited by their permits (and the Steam Electric ELGs) to only two hours per day per generating unit, and that the mean number of days these facilities chlorinate is 182 days per year[40]. EPA did not make similar adjustments to the data for industrial non-utilities because comparable data for chlorination practices at industrial non-utilities are not available. In addition and as previously stated, in many cases the effluent data for industrial non-utilities include other waste streams that may contribute chlorinated compounds on a daily basis.

9.4 Review of Industrial Non-Utility Discharge Permits

EPA reviewed NPDES permits for 28 industrial facilities operating a steam electric industrial non-utility on site to determine the extent to which steam electric process wastewater is segregated from other process wastewaters and whether Steam Electric ELGs are applied on the basis of BPJ. These facilities use either a fossil fuel or other non-fossil fuel to power the steam electric generating unit(s), and were identified within the following four industries:

- Chemical Manufacturing;
- Paper Manufacturing;
- Primary Metal Manufacturing; and
- Petroleum and Coal Products Manufacturing.

EPA found that the NPDES permits for the facilities within these industries rarely provide enough detail about the facility waste streams to identify the steam electric process wastewaters; however, some permits generally described waste streams that could include the non-utility waste streams or waste streams from other on-site operations (e.g., “cooling water,” “boiler blowdown”). Final effluent wastewaters from industrial sites are commingled at the point of discharge, if not upstream.

The 28 facilities are covered by seven existing industrial point source ELGs. As expected, EPA determined that wastewaters discharged from these industrial sites are often regulated at a minimum by the ELGs for the primary industrial process (e.g., OCPSF, Petroleum Refining). Rarely do the discharge requirements incorporate 40 CFR 423-based limits.

EPA researched three of these seven existing ELGs to determine whether the waste streams from the non-utility operations were included in determining the final effluent limitations. The Pulp, Paper & Paperboard ELGs (40 CFR 430) specifically defines its regulated process wastewater (in certain subparts) as including wastewaters generated by colocated non-utility power plants (see 40 CFR 430.01(m)).

[40] This correction to the steam electric facility records in the *PCSLoads2002* database is discussed in Chapter 5.

Comments received from the American Petroleum Institute (API) stated that petroleum refinery non-utilities primarily generate wastewater from boiler and cooling tower blowdown and demineralizer streams that are typically permitted as low-contaminant streams (i.e., low concentrations of toxics, oxygen demand, and nonconventional pollutants). API also commented that these streams possess the same wastewater characteristics as the petroleum refining wastewater with which they are commingled prior to discharge [API, 2005].

While the Pulp, Paper, & Paperboard ELGs were developed incorporating wastewaters from on-site steam electric power plants, this is not the case for all industrial ELGs. For example, the standards that regulate wastewater generated from the iron & steel manufacturing industry (40 CFR 420) do not incorporate nonprocess wastewaters, such as those from an on-site steam electric power plant (e.g., noncontact cooling water).

In many cases, the primary industry ELGs (or the permit for the industrial facility discharge) either contains a less stringent limit or does not address the pollutants included in the Steam Electric ELGs, most notably chlorine[41] (regulated as FAC or TRC by the Steam Electric ELGs). For example, this is the case for the Pulp, Paper, & Paperboard ELGs, which include wastewaters generated from on-site power plants, but do not currently regulate chlorine discharges.

9.5 Conclusions

While steam electric industrial non-utilities utilize similar operations and are expected to generate wastewater that is similar to that of the regulated steam electric industry, industrial non-utilities are generally much smaller, in terms of overall capacity. In addition, some industrial non-utilities are fueled by non-fossil-fuel/non-nuclear energy sources, typically associated with the industrial processes present.

Since the types and concentrations of pollutants found in steam electric process wastewaters are primarily driven by the type of fuel used, there are may be differences between the wastewater generated by certain industrial non-utilities using non-fossil fuels and that generated by regulated steam electric facilities that use coal, petroleum coke, oil, natural gas, or nuclear fuel. In addition, because industrial non-utilities tend to be smaller in terms of electric power production, the relative volume of wastewater discharged by these facilities is likely to be less than that discharged by regulated steam electric facilities.

The available wastewater characterization data for industrial non-utilities is inconclusive. While some of the reported loads for pollutants characteristically found in steam electric wastewaters are significant, at least a portion of these loads are probably generated by processes at the site other than steam electric power generation. However, EPA could not determine from the available data how much of the pollutant load is attributed to the steam electric processes.

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[41] As discussed previously in Chapter 5, chlorine is commonly used by steam electric facilities as a biocide in the cooling water system. Although EPA did not gather specific information about the chemicals used by industrial non-utilities as biocides, EPA expects that at least some industrial non-utilities use biocide chemicals similar to those used in the steam electric industry, such as chlorine and chlorinated compounds.

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