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Environmental and Sustainable Technology Evaluation - Biomass Co-firing in Industrial Boilers – Minnesota Power's Rapids Energy Center

Prepared by:

SOUTHERN RESEARCH INSTITUTE
Affiliated with the University of Alabama at Birmingham

Southern Research Institute
Under Subcontract to ERG

For:

EPA

U.S. Environmental Protection Agency
Office of Research and Development – Environmental Technology Verification Program

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THE ENVIRONMENTAL TECHNOLOGY VERIFICATION PROGRAM

Environmental and Sustainable Technology Evaluation (ESTE)

U.S. Environmental Protection Agency

SOUTHERN RESEARCH INSTITUTE

ESTE Joint Verification Statement

TECHNOLOGY TYPE:	Biomass Co-firing
APPLICATION:	Industrial Boilers
TECHNOLOGY NAME:	Wood Waste Co-firing With Coal
COMPANY:	Minnesota Power, Rapids Energy Center
ADDRESS:	Grand Rapids, Minnesota

The U.S. Environmental Protection Agency (EPA) has created the Environmental Technology Verification (ETV) program to facilitate the deployment of innovative or improved environmental technologies through performance verification and dissemination of information. The goal of the ETV program is to further environmental protection by accelerating the acceptance and use of improved and cost-effective technologies. ETV seeks to achieve this goal by providing high-quality, peer-reviewed data on technology performance to those involved in the purchase, design, distribution, financing, permitting, and use of environmental technologies. This verification was conducted under the Environmental and Sustainable Technology Evaluation (ESTE) program, a component of ETV that was designed to address agency priorities for technology verification.

The goal of the ESTE program is to further environmental protection by substantially accelerating the acceptance and use of improved and innovative environmental technologies. The ESTE program was developed in in response to the belief that there are many viable environmental technologies that are not being used for the lack of credible third-party performance data. With performance data developed under this program, technology buyers, financiers, and permitters in the United States and abroad will be better equipped to make informed decisions regarding environmental technology purchase and use.

This ESTE project involved evaluation of co-firing common woody biomass in industrial, commercial or institutional coal-fired boilers. For this project ERG was the responsible contractor and Southern Research Institute (Southern) performed the work under subcontract. Client offices within the EPA, those with an explicit interest in this project and its results, include: Office of Air and Radiation (OAR), Combined Heat and Power (CHP) Partnership, Office of Air Quality Planning and Standards (OAQPS), Combustion Group, Office of Solid Waste (OSW), Municipal and Industrial Solid Waste Division, and ORD's Sustainable Technology Division. Letters of support have been received from the U.S. Department of Agriculture Forest Service and the Council of Industrial Boiler Owners.

TECHNOLOGY DESCRIPTION

Minnesota Power's Rapids Energy Center (REC) hosted this testing. REC provides power and heat for the neighboring Blandin Paper Mill in Grand Rapids, Minnesota. The facility has two identical Foster Wheeler Spreader Stoker Boilers installed in 1980 (Boilers 5 and 6). This verification was conducted on Boiler 5. Each boiler has a steaming capacity of approximately 175,000 lb/hour. The boilers can be fired with western subbituminous coal supplied by Decker Coal Company, located in the northwest section of the Powder River Basin, wood waste, railroad ties, on-site generated waste oils and solvents, and other paper wastes. Particulate emissions from each boiler are controlled by a Zurn multiclone dust collector and cold side electrostatic precipitator (ESP).

Waste wood and bark from the neighboring Blandin Paper mill, as well as waste wood from other local facilities, was co-fired with coal during this verification. The fuels (woody biomass and coal) are conveyed to the boiler separately and mixed on the stoker. Proximate analyses of the woody biomass used for this testing is as follows (wet weight basis):

Component	% by Weight
Moisture	46.5
Ash	1.28
Fixed carbon	27.3

The average heating value of the woody biomass was 4,645 Btu/lb.

Under normal operations, each boiler generates approximately 175,000 lb/h steam which is used to power a 15 MW steam turbine and provide process steam to the Blandin mill. The boilers typically co-fire woody waste, primarily bark, at a nominal coal:biomass fuel ratio of 15:85 percent. The woody biomass waste is of sufficient supply nearly all year long with the exception of spring months. During periods of reduced wood waste supply the facility increases the amount of coal used to fuel the boilers.

VERIFICATION DESCRIPTION

This project was designed to evaluate changes in boiler performance due to co-firing woody biomass with coal. Boiler operational performance with regard to efficiency, emissions, and fly ash characteristics were evaluated while combusting 100 percent coal and then reevaluated while co-firing biomass with coal. The verification also addressed sustainability issues associated with biomass co-firing at this site.

The testing was limited to two operating points on Boiler 5:

- firing coal only at a typical nominal load
- firing a coal:biomass "co-firing" mixture of approximately 7:93 percent by weight at the same operating load

Under each condition, testing was conducted in triplicate with each test run approximately three hours in duration. In addition to the emissions evaluation, this verification addressed changes in fly ash composition. Fly ash can serve as a portland cement production component, structural fill, road materials, soil stabilization, and other beneficial uses. An important property that limits the use of fly ash is carbon content. Presence of metals in the ash, particularly mercury (Hg), can also limit fly ash use, such as in cement manufacturing. Biomass co-firing could impact fly ash composition and properties, so this verification included evaluation of changes in fly ash carbon burnout (loss on ignition), minerals, and metals content.

During testing, the verification parameters listed below were evaluated. This list was developed based on project objectives cited by the client organizations and input from the Biomass Co-firing Stakeholder Group (BCSG).

Verification Parameters:

- Changes in emissions due to biomass co-firing including:
  - Nitrogen oxides (NO_X)
  - Sulfur dioxide (SO_2)
  - Carbon monoxide (CO)
  - Carbon dioxide (CO_2)
  - Total particulates (TPM) (including condensable particulates)
  - Primary metals: arsenic (As), selenium (Se), zinc (Zn), and Hg
  - Secondary metals: barium (Ba), beryllium (Be), cadmium (Cd), chromium (Cr), copper (Cu), manganese (Mn), nickel (Ni), and silver (Ag)
  - Hydrogen chloride (HCl) and hydrogen fluoride (HF)
- Boiler efficiency
- Changes in fly ash characteristics including:
  - Carbon, hydrogen, and nitrogen (CHN), and SiO_2, Al_2O_3, and Fe_2O_3 content
  - Primary metals: As, Se, Zn, and Hg
  - Secondary metals: Ba, Be, Cd, Cr, Cu, Mn, Ni, and Ag
  - fly ash fusion temperature
  - Resource Conservation Recovery Act (RCRA) metals and Toxic Characteristic Leaching Procedure (TCLP).
- Sustainability indicators including CO_2 emissions associated with sourcing and transportation of biomass and ash disposal under baseline (no biomass co-firing) and test case (with biomass co-firing) conditions.

Rationale for the experimental design, determination of verification parameters, detailed testing procedures, test log forms, and QA/QC procedures can be found in Test and Quality Assurance Plan titled *Test and Quality Assurance Plan – Environmental and Sustainable Technology Evaluation Biomass Co-firing in Industrial Boilers.*

Quality Assurance (QA) oversight of the verification testing was provided following specifications in the ETV Quality Management Plan (QMP). Southern's QA Manager conducted a technical systems audit and an audit of data quality on a representative portion of the data generated during this verification and a review of this report. Data review and validation was conducted at three levels including the field team leader (for data generated by subcontractors), the project manager, and the QA manager. Through these activities, the QA manager has concluded that the data meet the data quality objectives that are specified in the Test and Quality Assurance Plan.

VERIFICATION OF PERFORMANCE

Boiler Efficiency

Table S-1. Boiler Efficiency

Test ID	Fuel	Heat Input (MMBtu/hr)	Heat Output (MMBtu/hr)	Efficiency (%)
Baseline 1	100 % Coal	296.6	220.4	74.3
Baseline 2		304.1	225.8	74.2
Baseline 3		295.7	221.3	74.9
Cofire 1	Blended Fuel (8 Coal; 92 Woody biomass)	368.4	227.9	61.8
Cofire 2		363.7	219.9	60.5
Cofire 3		357.8	220.1	61.5
Baseline Average		298.8	222.5	74.5 ± 0.3
Cofire Average		363.3	222.6	61.3 ± 0.7
Absolute Difference		64.5	0.1	-13.2
% Difference		21.8%	0.00%	-17.7%
Statistically Significant Change?		na	na	Yes

The average efficiencies during baseline (coal only) and co-firing tests were 74.5 ± 0.3 and 61.3 ± 0.7 percent respectively. This results in a statistically significant decrease of 17.7 percent efficiency when firing the blended fuel. The mass of woody fuel needed to provide an equal amount of heat is much greater. During baseline testing, an average 31,600 lb/h coal was consumed. During co-firing, fuel feed rates for coal and woody biomass averaged approximately 6,470 and 75,200 lb/h, respectively.

Emissions Performance

Table S-2. Gaseous Pollutants (lb/MMBtu)

Test ID	Fuel	SO_2	CO_2	NO_x	CO
Baseline 1	100 % Coal	0.489	167	0.533	0.229
Baseline 2		0.485	160	0.540	0.210
Baseline 3		0.448	153	0.509	0.251
Cofire 1	Blended Fuel	0.0013	131	0.188	0.680
Cofire 2		0.0014	127	0.193	0.337
Cofire 3		0.0012	134	0.201	0.649
Baseline Averages		0.474 ± 0.02	160 ± 7	0.527 ± 0.01	0.230 ± 0.02
Cofire Averages		0.0013 ± 0.0001	131 ± 4	0.194 ± 0.007	0.555 ± 0.2
% Difference		-99.7%	-18.3	-63.2%	142%
Statistically Significant Change?		Yes	Yes	Yes	Yes

As expected SO_2 emissions were essentially eliminated using this high blend of woody biomass. NO_X emissions were also greatly reduced when co-firing (less fuel-bound nitrogen and lower thermal NO_X formation due to higher fuel moisture content, both shown in Table 3-1), and there was a statistically significant change in CO_2 emissions and a large increase in CO emissions. In similar testing at a different facility, wood pellets were co-fired with coal at a much lower rate (about 15 percent) and at a much lower moisture content (about 7 percent). During that testing NO_X emissions were slightly increased and CO and CO_2 emissions were not significantly impacted. The two tests serve as a useful comparison between relatively dry and very moist woody fuels, and how this can impact emissions.

A large reduction in condensable particulates was evident while co-firing the woody fuel. Although there was not a significant change in emissions of filterable particulates, the total particulate emission rate was reduced by 81 percent due to the large decrease in condensable particulates.

Table S-3. Particulate Emissions (lb/MMBtu)

Test ID	Fuel	Total Particulate	Filterable PM	Condensable PM
Baseline 1	100 % Coal	0.0295	0.0044	0.0251
Baseline 2		0.0277	0.0042	0.0236
Baseline 3		0.0379	0.0049	0.0262
Cofire 1	Blended Fuel	0.0088	0.0055	0.0050
Cofire 2		0.0029	0.0031	0.0030
Cofire 3		0.0062	0.0026	0.0021
Baseline Averages		0.0317 ± 0.005	0.0045 ± 0.0004	0.0249 ± 0.0013
Cofire Averages		0.0060 ± 0.003	0.0037 ± 0.002	0.0034 ± 0.0015
Absolute Difference		-0.0257	-0.0008	-0.0216
% Difference		-81.2%	-17.1%	-86.5%
Statistically Significant Change?		Yes	No	Yes

Metals emissions were extremely low during all test periods. Changes in metals emissions on a percentage basis were large and quite variable across the elements analyzed, including the list of eight secondary metals. For the four primary metals shown, the reductions in mercury and selenium were statistically significant.

Emissions of HCl and HF were considerably lower during co-firing due the reduced levels of chlorine and fluorine in the fuel, showing decreases of approximately 62 and 77 percent, respectively. The reductions for both are statistically significant using the t-test.

Fly Ash Characteristics

Changes in ash characteristics were significant. Minerals content was much lower in the cofired fuel ash. Loss on ignition was significantly higher, indicating that the woody biomass is more difficult to fully combust. Changes in carbon content or fusion temperatures of the ash were not statistically significant. Quantitative flyash results are voluminous and not presented here, but can be viewed in the main body of the report in Tables 3-7 through 3-9.

Biomass co-firing during this verification did not impact the quality of the ash with regard to fly ash TCLP metals (40 CFR 261.24). Metals content was well below the TCLP requirements for all tests as shown in Table 3-8. Ash results did not meet the Class F Requirements (C 618-05) for use in concrete for either the baseline or co-fired fuels.

Sustainability Issues

- The REC receives woody biomass based fuel from the neighboring Blandin Mill and a wide variety of commercial suppliers throughout the northern plains region. During the first 6 months of 2007, the facility received a total of approximately 173,000 tons of woody biomass based fuel. Of that, approximately 83,000 tons came from the Blandin Mill, and the remaining 90,000 tons were purchased from commercial providers.

- Fuel and emissions associated with transportation of woody biomass to the Blandin Mill are not considered in this analysis since the woody biomass is transported to the facility whether used as fuel or not. Collected data show that approximately 33,000 gallons of diesel fuel was used to transport woody biomass based fuels from commercial suppliers to the REC (equating to an estimated 0.37 gallons per ton of woody biomass delivered). Based on an Energy Information Administration emission factor of 19.564 lbs CO_2/gallon, CO_2 emissions per ton of woody biomass based fuel transported to the facility are:

  7.2 lbs CO_2 / ton woody biomass (0.37 gal fuel /ton pellets * 19.564 lbs CO_2/gal).
  648 tons CO_2 annually (7.2 lb/ton * 180,000 tons woody biomass delivered annually).

- Based on data generated during this testing, the CO_2 emission rates while firing straight coal and blended fuel (at a blending rate of approximately 92 percent woody biomass by mass) were 160 and 165 lb/MMBtu, respectively. However, combustion of wood-based fuel, which is composed of biogenic carbon, emits no appreciable CO_2 emissions under international greenhouse gas accounting methods developed by the IPCC and adopted by the ICFPA [6]. By analyzing the heat content of the coal and the woody biomass, the total boiler heat input for the test periods, and boiler efficiency, it was determined that approximately 90 percent of the heat generated during co-firing test periods is attributable to the wood-based fuel. It is therefore estimated that the CO_2 emissions offset during this testing is approximately 90 percent, or 148 lb/MMBtu at this co-firing blend. REC Boiler 5 typically operates around 220 MMBtu/hr heat generating rate. Assuming an availability and utilization rate of 75 percent for Boiler 5 at this heat rate, this would equate to estimated annual CO_2 emission reductions of approximately 107,000 tons per year.

- The mass of woody fuel needed to provide an equal amount of heat is much greater. During baseline testing, an average 31,600 lb/h coal was consumed. During co-firing, fuel feed rates for coal and woody biomass averaged approximately 6,470 and 75,200 lb/h, respectively.

- Biomass co-firing during this verification did not impact the quality of the ash with regard to fly ash TCLP metals (40 CFR 261.24). Metals content was well below the TCLP requirements for all tests. Ash results did not meet the Class F Requirements (C 618-05) for use in concrete for either the baseline or co-fired fuels. As such, biomass co-firing did not impact either sustainability issue since the quality of the ash with regard to fly ash TCLP metals and Class F Requirements was unchanged.

Details on the verification test design, measurement test procedures, and Quality Assurance/Quality Control (QA/QC) procedures can be found in the Test Plan titled *Test and Quality Assurance Plan – Environmental and Sustainable Technology Evaluation Biomass Co-firing in Industrial Boilers.* (Southern 2006). Detailed results of the verification are presented in the Final Report titled *Environmental and Sustainable Technology Evaluation Biomass Co-firing in Industrial Boilers – Minnesota Power's Rapids Energy Center* (Southern 2007). Both can be downloaded from Southern's web-site (www.sri-rtp.com) or the ETV Program web-site (www.epa.gov/etv).

Signed by: Sally Gutierrez – April 28, 2008	Tim Hansen – April 3, 2008
Sally Gutierrez Director National Risk Management Research Laboratory Office of Research and Development	Tim Hansen Program Director Southern Research Institute

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Southern Research Institute

Environmental and Sustainable Technology Evaluation

Biomass Co-firing in Industrial Boilers

Minnesota Power's Rapids Energy Center

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TABLE OF CONTENTS

APPENDICES

LIST OF FIGURES

LIST OF TABLES

DISTRIBUTION LIST

U.S. EPA – Office of Research and Development
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Acronyms and Abbreviations

Ag	silver
As	arsenic
Ba	barium
Be	beryllium
BCSG	Biomass Co-firing Stakeholder Group
Btu	British thermal unit
Btu/h	British thermal unit per hour
Cd	cadmium
CEMS	continuous emissions monitoring system
CHN	carbon, hydrogen, and nitrogen
CHP	combined heat and power
CO	carbon monoxide
CO_2	carbon dioxide
Cr	chromium
Cu	copper
DQO	data quality objective
EPA-ORD	Environmental Protection Agency Office of Research and Development
ESP	electrostatic precipitator
ESTE	Environmental and Sustainable Technology Evaluation
ETV	Environmental Technology Verification
gr/dscf	grains per dry standard cubic foot
HCl	hydrogen chloride
HF	hydrogen fluoride
Hg	mercury
ICI	industrial-commercial-institutional
kW	kilowatt
lb/h	pounds per hour
lb/lb-mol	pounds per pound-mole
MMBtu/h	million British thermal units per hour
Mn	manganese
MQO	measurement quality objective
MW	megawatt
Ni	nickel
NO_X	nitrogen oxides
O_2	oxygen
QA / QC	quality assurance / quality control
OAQPS	Office of Air Quality Planning and Standards
OAR	Office of Air and Radiation
OSW	Office of Solid Waste
ppmvd	parts per million by volume, dry
psig	pounds per square inch, gauge
REC	Rapids Energy Center
Se	selenium
SO_2	sulfur dioxide
T	tons (English)
TCLP	Toxic Characteristic Leaching Procedure.
TPM	total particulate matter
TQAP	test and quality assurance plan
Zn	zinc
^oF	degrees Fahrenheit

ACKNOWLEDGMENTS

Southern Research Institute wishes to thank the ETV-ESTE program management, especially Theresa Harten, David Kirchgessner, and Robert Wright for supporting this verification and reviewing and providing input on the testing strategy and this Verification Report. Thanks are also extended to the Rapids Energy Center for hosting the test, especially Compliance Superintendent Doug Tolrud, Plant Engineer Jim Uzelak, Lead Station Operator Gordon Ranta, and Instrument and Lab Specialist Nick Wooner. Their input supporting the verification and assistance with coordinating field activities was invaluable to the project's success.

1.0 INTRODUCTION

1.1 BACKGROUND

The U.S. Environmental Protection Agency's Office of Research and Development (EPA-ORD) operates the Environmental and Sustainable Technology Evaluation (ESTE) program to facilitate the deployment of innovative technologies through performance verification and information dissemination. In part, the ESTE program is intended to increase the relevance of Environmental Technology Verification (ETV) Program projects to the U.S. EPA program and regional offices.

The goal of the ESTE program is to further environmental protection by substantially accelerating the acceptance and use of improved and innovative environmental technologies. The ESTE program was developed in response to the belief that there are many viable environmental technologies that are not being used for the lack of credible third-party performance data. With performance data developed under this program, technology buyers, financiers, and permitters in the United States and abroad will be better equipped to make informed decisions regarding environmental technology purchase and use.

The ESTE program involves a three step process. The first step is a technology category selection process conducted by ORD. The second step involves selection of the project team and gathering of project collaborators and stakeholders. Collaborators can include technology developers, vendors, owners, and users and support the project through funding, cost sharing, and technical support. Stakeholders can include representatives of regulatory agencies, trade organizations relevant to the technology, and other associated technical experts. The project team relies on stakeholder input to improve the relevance, defensibility, and usefulness of project outcomes. Both collaborators and stakeholders are critical to development of the project test and quality assurance plan (TQAP), the end result of step two. Step three includes the execution of the verification and quality assurance and review process for the final reports.

This ESTE project involved evaluation of co-firing common woody biomass in industrial, commercial or institutional coal-fired boilers. For this project ERG was the responsible contractor and Southern Research Institute (Southern) performed the work under subcontract. Client offices within the EPA, those with an explicit interest in this project and its results, include: Office of Air and Radiation (OAR), Combined Heat and Power (CHP) Partnership, Office of Air Quality Planning and Standards (OAQPS), Combustion Group, Office of Solid Waste (OSW), Municipal and Industrial Solid Waste Division, and ORD's Sustainable Technology Division. Letters of support have been received from the U.S. Department of Agriculture Forest Service and the Council of Industrial Boiler Owners.

With increasing concern about global warming and fossil fuel energy supplies, there continues to be an increasing interest in biomass as a renewable and sustainable energy source. Many studies and research projects regarding the efficacy and environmental impacts of biomass co-firing have been conducted on large utility boilers, but less data is available regarding biomass co-firing in industrial size boilers. As such, OAQPS has emphasized an interest in biomass co-firing in industrial-commercial-institutional (ICI) boilers in the 100 to 1000 million British thermal units per hour (MMBtu/h) range. The reason for this emphasis is to provide support for development of a new area-source "Maximum Achievable Control Technology" standard.

The focus for this project was to evaluate performance and emission reductions for ICI boilers as a result of biomass co-firing. The primary objectives of this project were to:

- Evaluate changes in boiler emissions due to biomass co-firing
- Evaluate boiler efficiency with biomass co-firing
- Examine any impact on the value and suitability of fly ash for beneficial uses (carbon and metals content)
- Evaluate sustainability indicators including emissions from sourcing and transportation of biomass and disposal of fly ash

This document is one of two Technology Evaluation Reports for this ESTE project. This report presents results of the testing conducted on Unit 5 at Minnesota Power's Rapids Energy Center (REC) in Grand Rapids, Minnesota. This report includes the following components:

- Brief description of the verification approach and parameters (§ 2.0)
- Description of the test location (§ 2.1)
- Brief description of sampling and analytical procedures (§ 2.2)
- Test results (§ 3.0)
- Data quality (§ 4.0)

This report has been reviewed by representatives of ORD, OAQPS, OSW, the EPA QA team, and the project stakeholders and collaborators. It documents test operations and verification results. It is available in electronic format from Internet sites maintained by Southern (www.sri-rtp.com) and ETV program (www.epa.gov/etv).

2.0 VERIFICATION APPROACH

This project was designed to evaluate changes in boiler performance due to co-firing woody biomass with coal. Boiler operational performance with regard to efficiency, emissions, and fly ash characteristics were evaluated while combusting 100 percent coal and then reevaluated while co-firing biomass with coal. The verification also addressed sustainability issues associated with biomass co-firing at this site.

The testing was limited to two operating points on Unit 5 at REC:

- firing coal only at a typical nominal load
- firing a coal:biomass "co-firing" mixture of approximately 8:92 percent by weight at the same operating load

In addition to the emissions evaluation, this verification addressed changes in fly ash composition. Fly ash can serve as a portland cement production component, structural fill, road materials, soil stabilization, and other beneficial uses. An important property that limits the use of fly ash is carbon content. Presence of metals in the ash, particularly mercury (Hg), can also limit fly ash use, such as in cement manufacturing. Biomass co-firing could impact fly ash composition and properties, so this verification included evaluation of changes in fly ash carbon burnout (loss on ignition), minerals, and metals content.

During testing, the verification parameters listed below were evaluated. This list was developed based on project objectives cited by the client organizations and input from the Biomass Co-firing Stakeholder Group (BCSG).

<u>Verification Parameters:</u>

- Changes in emissions due to biomass co-firing including:
  - Nitrogen oxides (NO_X)
  - Sulfur dioxide (SO_2)
  - Carbon monoxide (CO)
  - Carbon dioxide (CO_2)
  - Total particulates (TPM) (including condensable particulates)
  - Primary metals: arsenic (As), selenium (Se), zinc (Zn), and Hg
  - Secondary metals: barium (Ba), beryllium (Be), cadmium (Cd), chromium (Cr), copper (Cu), manganese (Mn), nickel (Ni), and silver (Ag)
  - Hydrogen chloride (HCl) and hydrogen fluoride (HF)
- Boiler efficiency
- Changes in fly ash characteristics including:
  - Carbon, hydrogen, and nitrogen (CHN), and SiO_2, Al_2O_3, and Fe_2O_3 content
  - Primary metals: As, Se, Zn, and Hg
  - Secondary metals: Ba, Be, Cd, Cr, Cu, Mn, Ni, and Ag
  - fly ash fusion temperature
  - Resource Conservation Recovery Act (RCRA) metals and Toxic Characteristic Leaching Procedure (TCLP).

– Sustainability indicators including CO_2 emissions associated with sourcing and transportation of biomass and ash disposal under baseline (no biomass co-firing) and test case (with biomass co-firing) conditions.

2.1 HOST FACILITY AND TEST BOILER

Testing was conducted on two industrial boilers that are capable of co-firing woody biomass. The two units that hosted tests were Minnesota Power's REC Boiler 5 (MP-5) and the University of Iowa Main Power Plant's Boiler 10 (UI-10). Results of the UI-10 testing are published under separate cover and can be found at www.sri-rtp.com.

Minnesota Power's REC provides power and heat for the neighboring Blandin Paper Mill in Grand Rapids, Minnesota. The facility has two identical Foster Wheeler Spreader Stoker Boilers installed in 1980 (Boilers 5 and 6). This verification was conducted on Boiler 5. Each boiler has a steaming capacity of approximately 175,000 lb/hour. The boilers can be fired with western subbituminous coal supplied by Decker Coal Company, located in the northwest section of the Powder River Basin, wood waste, railroad ties, on-site generated waste oils and solvents, and other paper wastes. Particulate emissions from each boiler are controlled by a Zurn multiclone dust collector and cold side electrostatic precipitator (ESP). Cleaned flue gas from each boiler exhausts to the atmosphere via a common stack which is 205 feet above elevation and has an inner diameter of 9 feet. Figure 2-1 is a schematic of the boilers.

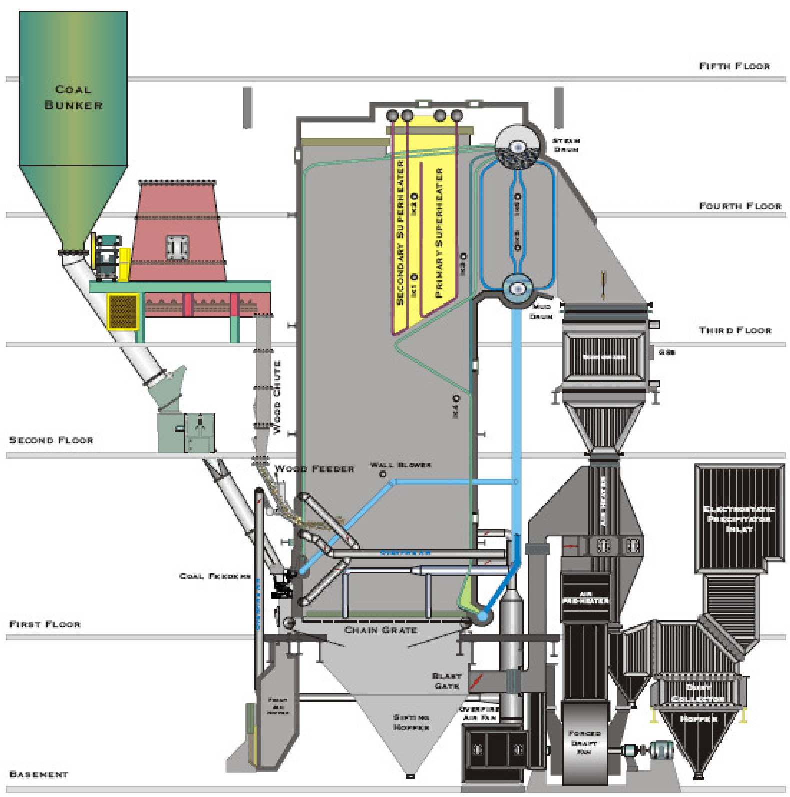

Figure 2-1. Minnesota Power's Foster Wheeler Spreader Stokers

Since both boilers exhaust through a common stack, emission testing for this program was conducted in the ductwork of the selected boiler upstream of the stack. The testing location and ports are shown in Figure 2-2.

Figure 2-2. Emission Testing Ports for MP-5

Under normal operations, each boiler generates approximately 175,000 lb/h steam which is used to power a 15 MW steam turbine and provide process steam to a nearby industrial facility. The boilers typically co-fire woody waste, primarily bark, at a nominal coal:biomass fuel ratio of 15:85 percent. The woody biomass waste is of sufficient supply nearly all year long with the exception of spring months. During periods of reduced wood waste supply the facility increases the amount of coal used to fuel the boilers. More details regarding the fuels used for this test is presented in Section 2.2.2.

Fly ash generated by this boiler is collected from the dust collector and precipitator and distributed to farms for crop use as long as the fuel blend is less than 50 percent coal. In 2003, approximately 7,700 tons of ash was distributed to farms. When coal exceeds 50 percent, the ash is landfilled.

The systems data control system (DCS) includes a PI Historian software package that allows the facility to customize data acquisition, storage, and reporting activities. Each boiler is also equipped with continuous emission monitoring systems (CEMS) that record NO_X, SO_2, CO, and O_2 concentrations and emission rates. Table 2-1 summarizes the CEMS on each boiler.

Table 2-1. MP-5 CEMS

Parameter	Instrument Make/Model	Instrument Range	Reporting Units
NO_X	Teledyne Monitor Labs (TML) 41-H-O2	0 – 500 ppm	lb/MMBtu
SO_2	TML 50-H	0 – 1000 ppm	lb/MMBtu
CO	TML 30-M	0 – 5000 ppm	lb/MMBtu
O_2	TML 41-H-O2	0 – 25 %	%

The facility has a fully equipped control room that continuously monitors boiler operations. Operational parameters that were recorded during this test program include the following:

- Heat input, (Btu/h)
- Steam flow (lb/h)
- Steam pressures (psig) and temperatures (^oF)
- Air flows (lb/h) and temperatures (^oF)
- Power output (MW)
- SO_2 emissions (lb/MMBtu)
- ESP variables (volts, amperes, fields on line), recorded manually

Data recorded during each test period was averaged over the test period and reported to document boiler operations during the testing, co-firing rates, and boiler efficiency. Key parameters such as heat input and steam flow are summarized in the results section of this report. Dust collector and ESP operational data are summarized in Appendix E.

2.2 FIELD TESTING

Waste wood and bark from the neighboring Blandin Paper mill, as well as waste wood from other local facilities, was co-fired with coal during this verification. The fuels (woody biomass and coal) are conveyed to the boiler separately and mixed on the stoker. Figure 2-3 shows the woody biomass conveyer during verification testing.

Figure 2-3. Rapids Energy Woody biomass Feed

Proximate analyses of the woody biomass used for this testing is as follows (wet weight basis):

Component	% by Weight
Moisture	46.5
Ash	1.28
Fixed carbon	27.3

The average heating value of the woody biomass was 4,645 Btu/lb. These values are the average of three composite samples collected on the day of testing and may not reflect variability in the woody biomass used at REC.

2.2.1 Field Testing Matrix

A set of three replicate tests were conducted while firing coal only on March 28, 2007. The following day, a second set of three tests were conducted while firing primarily woody biomass co-fired with a small amount of coal. Duration of each test run was approximately 120 minutes. Other than changes in fuel composition, all other boiler operations were replicated as closely as possible during test sets. Test and sampling procedures were also consistent between sets of tests. Table 2-2 summarizes the test matrix.

Table 2-2. Rapids Energy Boiler 5 Test Periods

Date	Time	Test ID	Fuel	Heat Input (MMBtu/h)	Steam Flow (Klb/h)
03-28-07	0940 – 1215	Baseline 1	100 % coal	296.6	153.6
	1250 – 1520	Baseline 2		304.1	157.3
	1555 - 1825	Baseline 3		295.7	154.2
03-29-07	0815 - 1050	Cofire 1	Blended Fuel (8 % Coal; 92 % woody biomass)	293.5	159.2
	1228 - 1500	Cofire 2		285.2	153.7
	1520 - 1750	Cofire 3		285.6	153.9

All testing was conducted during stable boiler operations (defined as boiler steam flows varying by less than 5 percent over a 5 minute period). Southern representatives coordinated testing activities with boiler operators to ensure that all testing was conducted at the desired boiler operating set points and the boiler operational data needed to calculate efficiency was properly logged and stored. Southern also supervised all emissions testing activities.

2.3 BOILER PERFORMANCE METHODS AND PROCEDURES

Conventional field testing protocols and reference methods were used to determine boiler efficiency, emissions, and fly ash properties. A brief description of the methods and procedures is provided here. Details regarding the protocols and methods proposed are provided in the document titled: *Test and Quality Assurance Plan – Environmental and Sustainable Technology Evaluation – Biomass Co-firing in Industrial Boilers* [1].

2.3.1 Boiler Efficiency

Boiler efficiency was determined following the Btu method in the B&W Steam manual [2]. The efficiency determinations were also used to estimate boiler heat input during each test period. The facility logs all of the data required for determination of boiler efficiency on a regular basis. Certain parameters such as ambient conditions and flue gas temperatures were independently measured by Southern. Table 2-3 summarizes the boiler operational parameters logged during testing and the source and logging frequency for each.

Table 2-3. Summary of Boiler Efficiency Parameters

Operational Parameter	Source of Data	Logging Frequency
Intake air temperature, °F	Southern measurements	Five minute intervals
Flue gas temperature at air heater inlet, °F		
Fuel temperature, °F	Southern measurements	Twice per test run
Moisture in air, lb/lb dry air		
Fuel consumption, lb/h	Facility PI Historian Control System	One minute averages
Combustion air temperature, °F		
Steam flow, MMBtu/h or lb/h		
Steam pressure, psig		
Steam temperature, °F		
Supply water pressure, psig		
Supply water temperature, °F		
Power generation, kW		
Fuel ultimate analyses, both woody biomass and coal	Analytical laboratory	One composite coal, mixed fuel, and fly ash sample per test (3 total for each condition)
Fuel heating value, Btu/lb		
Unburned carbon loss, %		

Fuel feed rates were monitored during the verification testing to confirm fuel blending rates (fuel feed rate is not required for the boiler efficiency calculations via the Btu method). Woody biomass feed rates to the boiler are monitored by the site using a belt scale. Coal firing rates are determined by counting and recording the number of hopper releases over a given period of time, and assigning an assumed mass of coal per release. The coal feed rate data were later determined to be invalid. Therefore, fuel blending rate was derived using the total calculated heat input, the measured woody biomass feed rate, and the measured heating value of the woody biomass and the coal.

2.3.1.1 Fuel Sampling and Analyses

Fuel samples were collected during each test run for ultimate and heating value analysis. A composite of grab samples of coal and biomass were prepared during co-firing test runs and submitted to Wyoming Analytical Laboratories, Inc. in Laramie, Wyoming for the analyses shown in Table 2-4.

Table 2-4. Summary of Fuel Analyses

Parameter	Method
Ultimate analysis	ASTM D3176
Gross calorific value	ASTM D5865 (coal) ASTM E711-87 (biomass)

Grab samples of each fuel (coal and woody biomass separately) were collected from the fuel conveyers immediately above the stoker feed hopper. The grabs contained approximately one lb of fuel and were collected at 30 minute intervals during each test run and combined in a large pail. One mixed composite sample of approximately one lb each fuel was generated for each test run, sealed and submitted for analysis. Collected composite samples were labeled, packed and shipped to Wyoming Analytical along with completed chain-of-custody documentation for off-site analysis. These samples were submitted to the field team leader for subsequent analysis. The ultimate analysis reported the following fuel constituents as percent by weight (wet):

- carbon
- water
- ash
- sulfur
- nitrogen
- hydrogen
- oxygen

The efficiency analysis requires the unburned carbon loss value, or carbon content of fly ash. Fly ash samples were also collected during each test run and submitted for analysis. Prior to each test run, precipitator ash hoppers were cleared of residual ash. Grab samples of ash were then collected from a hopper at 30 minute intervals during each test run and combined in a gallon size metal ash sampling can. Collected ash samples were then sealed in plastic bags, labeled, packed and shipped to Wyoming Analytical along with completed chain-of-custody documentation for off-site analysis. Results of these analyses were used to complete the combustion gas calculations in the Btu method.

2.3.2 Boiler Emissions

Testing was conducted on each boiler to determine emissions of the following atmospheric pollutants:

- nitrogen oxides (NO_x)
- sulfur dioxide (SO_2)
- particulate matter (filterable and condensable)
- carbon monoxide (CO)
- carbon dioxide (CO_2)
- primary metals (As, Hg, Se, Zn)
- secondary metals
- acid gases (HCl, HF)

Emission rates for NO_X, SO_2, and CO were determined continuously using the facility's continuous emissions monitoring system (CEMS). For all other parameters, a total of three replicate test runs were conducted under both the baseline (coal only) and co-firing operating conditions. Each test run was approximately 120 minutes in duration.

Measurements required for emissions tests include:

- fuel heat input, Btu/h (via boiler efficiency, Section 2.3.1)
- pollutant and O_2 concentrations, parts per million (ppm), grains per dry standard cubic foot (gr/dscf), or percent
- flue gas molecular weight, pounds per pound-mole (lb/lb-mol)
- flue gas moisture concentration, percent
- flue gas flow rate, dry standard cubic feet per hour (dscfh)

The average concentrations established as part of each test run are reported in units of ppmvd for NO_X, CO, SO_2, HCl, and HF, and percent for CO_2. Concentrations of total particulate matter are reported as grains per dry standard cubic foot (gr/dscf). The average emission rates for each pollutant are also reported in units of pounds per hour (lb/h), and pounds per million Btu (lb/MMBtu).

All testing was conducted by GE Energy following EPA Reference or Conditional Methods for emissions testing [3]. Table 2-5 summarizes the reference methods used and the fundamental analytical principle for each method.

Table 2-5. Summary of Emission Test Methods and Analytical Equipment

Parameter or Measurement	U.S. EPA Reference Method	Principle of Detection
CO_2	3A	Non-dispersive infra-red
TPM	5	Gravimetric
condensable PM	CTM040/202	Gravimetric
Metals	29	Inductively coupled plasma / cold vapor atomic absorption spectroscopy
HCl, HF	26	Ion chromatography
Moisture	4	Gravimetric
Flue gas flow rate	2	Pitot traverse

2.3.3 Fly ash Characteristics

Fly ash samples were collected during the efficiency and emissions testing periods to evaluate the impact of biomass co-firing on ash composition. Fly ash samples were collected from from the ESP collection hoppers during each test run. Hoppers were cleaned out between runs. Collected samples were submitted to Wyoming Analytical along with completed chain-of-custody documentation for determination of the parameters listed below. The laboratory also conducted tests to evaluate ash fusion temperature, and air-entraining agents index. Results are compared to the Class F (bituminous and anthracite) or Class C (lignite and sub bituminous) fly ash specifications. Table 2-6 summarizes the analytical methods that were used.

Table 2-6. Summary of Fly ash Analyses

Parameter	Method
CHN	ASTM D5373
minerals	ASTM D4326-04
RCRA metals	SW-846 3052/6010
Metals TCLP	SW-846 1311/6010
Air-entraining agents index	Foam Index Test
Fly ash fusion temperature	ASTM D1857

2.4 SUSTAINABILITY INDICATORS AND ISSUES

Sustainability is an important consideration regarding use of woody biomass as a renewable fuel source. This project evaluated certain sustainability issues for the Rapids Energy facility. The following sustainability related issues were examined:

- Estimated daily and annual woody biomass consumption at the nominal co-firing rate
- Biomass delivery requirements (distance and mode)
- Coal delivery requirements (distance and mode)

<u>Biomass Consumption, Type, and Source</u>

The projected daily and annual biomass consumption rate is useful in determining whether the supply of biomass is sustainable. Biomass consumption rates measured during the testing conducted at each site were used as the basis to estimate daily and annual biomass consumption for each site. The source, type, and compositional analyses of the biomass was documented during testing.

<u>Associated GHG Emissions</u>

By evaluating the average biomass consumption rate during the testing, upstream CO_2 emissions associated with the biomass supply were estimated. The distance between the biomass source and the boiler tested along with CO_2 emission factors for the modes of transportation used to deliver the biomass were used to complete this analysis. Emission factors were determined based on EPA's AP 42 Emission Factors Database [4].

<u>Solid Waste Issues (Ash utilization)</u>

Results of the baseline coal fly ash analyses and the co-fired fuel fly ash analyses were compared to determine if co-firing biomass has a measurable impact on the carbon content of the ash with respect to ASTM standards for cement admixtures. In addition, results of the RCRA metals analyses for the baseline and co-fire ash were compared to evaluate impact on metals content. The metals TCLP analytical results were used to examine if co-firing impacts fly ash characteristics with respect to the TCLP standards cited in 40 CFR 261.24 [5].

3.0 RESULTS

Results of the testing are summarized in the following sections. Field and analytical data generated during the verification are presented in Appendices A through D including detailed emissions testing data, fuel and ash analyses, boiler efficiency calculations, and REC woody biomass delivery records. As expected, the facility was able to operate under both conditions (coal only and co-firing) without difficulties. Due to lack of demand from the host paper mill, all testing was conducted at approximately 88 percent of boiler capacity (approximately 155,000 lb/h steam). Using the total calculated heat input, the measured woody biomass feed rate, and the measured heating value of the woody biomass and the coal, the fuel blending rate was determined to be an average of 8 percent coal and 92 percent woody biomass during co-firing.

As part of the data analysis, results were analyzed to evaluate changes in boiler performance and fly ash characteristics between the two sets of tests. Standard deviations of the replicate measurements conducted under each fueling condition and a statistical analysis (t-test with a 90 percent confidence interval) were used to verify the statistical significance of any observed changes in emissions or efficiency.

3.1 BOILER EFFICIENCY

Table 3-1 summarizes the major fuel characteristics for both coal and blended fuel. Detailed fuel analyses, including results on a dry basis, are presented in Appendix B.

Table 3-1. Fuel Characteristics (as received)

Test ID	Fuel	Moisture (%)	Carbon (%)	Nitrogen (%)	Sulfur (%)	Ash (%)	Heating Value (Btu/lb)
Baseline 1	100 % Coal	23.5	54.2	0.93	0.33	3.95	9,445
Baseline 2		23.6	54.8	1.12	0.33	3.59	9,491
Baseline 3		23.9	54.4	0.54	0.33	3.98	9,422
Cofire 1	Blended Fuel (8 Coal; 92 woody biomass)	43.6	29.6	0.30	0.04	1.65	5,025
Cofire 2		46.0	29.0	0.42	0.05	1.16	4,930
Cofire 3		44.7	29.4	0.44	0.04	1.79	5,085
Baseline Averages		23.7	54.5	0.86	0.33	3.84	9,453
Cofire Averages		44.8	29.3	0.39	0.04	1.53	5,014
% Difference		89.2%	-46.2%	-55.2%	-86.9%	-60.1%	-47.0%

As expected, the moisture content of the blended fuel was much higher than the coal, and carbon, ash and heating values were much lower.

The average efficiencies during baseline (coal only) and co-firing tests were 74.5 ± 0.3 and 61.3 ± 0.7 percent respectively. This results in a statistically significant decrease of 17.7 percent efficiency when firing the blended fuel. Combustion appeared to occur higher up the boiler with; this was observed by the camera inside the boiler. Table 3-2 summarizes boiler efficiency during the test periods

Table 3-2. Boiler Efficiency

Test ID	Fuel	Heat Input (MMBtu/hr)	Heat Output (MMBtu/hr)	Efficiency (%)
Baseline 1	100 % Coal	296.6	220.4	74.3
Baseline 2		304.1	225.8	74.2
Baseline 3		295.7	221.3	74.9
Cofire 1	Blended Fuel (8 Coal; 92 Woody biomass)	368.4	227.9	61.8
Cofire 2		363.7	219.9	60.5
Cofire 3		357.8	220.1	61.5
Baseline Average		298.8	222.5	74.5 ± 0.3
Cofire Average		363.3	222.6	61.3 ± 0.7
Absolute Difference		64.5	0.1	-13.2
% Difference		21.8%	0.00%	-17.7%
Statistically Significant Change?		na	na	Yes

The mass of woody fuel needed to provide an equal amount of heat is much greater. During baseline testing, an average 31,600 lb/h coal was consumed. During co-firing, fuel feed rates for coal and woody biomass averaged approximately 6,470 and 75,200 lb/h, respectively.

3.2 BOILER EMISSIONS

Table 3-3 summarizes emission rates for the gaseous pollutants evaluated. As expected SO_2 emissions were essentially eliminated using this high blend of woody biomass. NO_X emissions were also greatly reduced when co-firing (less fuel-bound nitrogen and lower thermal NO_X formation due to higher fuel moisture content, both shown in Table 3-1), and there was a statistically significant change in CO_2 emissions and a large increase in CO emissions. In similar testing at a different facility, wood pellets were co-fired with coal at a much lower rate (about 15 percent) and at a much lower moisture content (about 7 percent). During that testing NO_X emissions were slightly increased and CO and CO_2 emissions were not significantly impacted. The two tests serve as a useful comparison between relatively dry and very moist woody fuels, and how this can impact emissions.

Regarding CO_2 emissions, it should be noted that combustion of wood-based fuel, which is composed of biogenic carbon, emits no appreciable CO_2 emissions under international greenhouse gas accounting methods developed by the Intergovernmental Panel of Climate Change (IPCC) and adopted by the International Council of Forest and Paper Associations (ICFPA). Therefore, the facility realizes a significant annual reduction in CO_2 emissions when co-firing wood (see Section 3.4.1)

Table 3-3. Gaseous Pollutants (lb/MMBtu)

Test ID	Fuel	SO_2	CO_2	NO_x	CO
Baseline 1	100 % Coal	0.489	167	0.533	0.229
Baseline 2		0.485	160	0.540	0.210
Baseline 3		0.448	153	0.509	0.251
Cofire 1	Blended Fuel	0.0013	131	0.188	0.680
Cofire 2		0.0014	127	0.193	0.337
Cofire 3		0.0012	134	0.201	0.649
Baseline Averages		0.474 ± 0.02	160 ± 7	0.527 ± 0.01	0.230 ± 0.02
Cofire Averages		0.0013 ± 0.0001	131 ± 4	0.194 ± 0.007	0.555 ± 0.2
% Difference		-99.7%	-18.3	-63.2%	142%
Statistically Significant Change?		Yes	Yes	Yes	Yes

Table 3-4 summarizes results of filterable, condensable, and total particulate emissions.

Table 3-4. Particulate Emissions (lb/MMBtu)

Test ID	Fuel	Total Particulate	Filterable PM	Condensable PM
Baseline 1	100 % Coal	0.0295	0.0044	0.0251
Baseline 2		0.0277	0.0042	0.0236
Baseline 3		0.0379	0.0049	0.0262
Cofire 1	Blended Fuel	0.0088	0.0055	0.0050
Cofire 2		0.0029	0.0031	0.0030
Cofire 3		0.0062	0.0026	0.0021
Baseline Averages		0.0317 ± 0.005	0.0045 ± 0.0004	0.0249 ± 0.0013
Cofire Averages		0.0060 ± 0.003	0.0037 ± 0.002	0.0034 ± 0.0015
Absolute Difference		-0.0257	-0.0008	-0.0216
% Difference		-81.2%	-17.1%	-86.5%
Statistically Significant Change?		Yes	No	Yes

A large reduction in condensable particulates was evident while co-firing the woody fuel. Although there was not a significant change in emissions of filterable particulates, the total particulate emission rate was reduced by 81 percent due to the large decrease in condensable particulates. Dust collector and ESP operational data presented in Appendix E indicate that conditions were consistent between the two sets of runs with regard to control device operations.

Table 3-5. Primary Metals Emissions (lb/MMBtu)

Test ID	Fuel	Arsenic	Mercury	Selenium	Zinc
Baseline 1	100 % Coal	9.61E-07	2.44E-06	2.04E-06	2.56E-05
Baseline 2		2.11E-06	2.40E-06	2.13E-06	1.53E-05
Baseline 3		8.12E-07	2.07E-06	2.35E-06	1.45E-05
Cofire 1	Blended Fuel	4.83E-07	9.39E-07	6.11E-07	1.91E-05
Cofire 2		4.67E-07	7.84E-07	8.83E-07	2.51E-05
Cofire 3		4.89E-07	8.33E-07	9.05E-07	2.20E-05
Baseline Averages		1.29E-06 ± 7.71E-07	2.30E-06 ± 2.01E-07	2.18E-06 ± 1.60E-07	1.84E-05 ± 6.20E-06
Cofire Averages		4.80E-07 ± 8.42E-09	8.52E-07 ± 9.36E-08	8.00E-07 ± 2.10E-07	2.21E-05 ± 4.04E-06
Absolute Difference		-8.15E-07	-1.45E-06	-1.38E-06	3.64E-06
% Difference		-62.9%	-63.0%	-63.2%	19.5%
Statistically Significant Change?		No	Yes	Yes	No

Metals emissions (primary metals summarized in Table 3-5) were extremely low during all test periods. Changes in metals emissions on a percentage basis were large and quite variable across the elements analyzed, including the list of eight secondary metals. Absolute differences are shown in the table to demonstrate how low metals emissions were, causing the large changes on a percent difference basis. For the four primary metals shown, the reductions in mercury and selenium were statistically significant.

Acid gas emissions are summarized below. Emissions of HCl and HF were considerably lower during co-firing due the reduced level of chlorine in the fuel. The reductions for both are is statistically significant using the t-test.

Table 3-6. Acid Gas Emissions (lb/MMBtu)

Test ID	Fuel	Hydrochloric Acid, HCl	Hydrofluoric Acid, HF
Baseline 1	100 % Coal	4.83E-04	2.18E-03
Baseline 3		6.07E-04	2.25E-03
Baseline 3		5.45E-04	2.07E-03
Cofire 1	Blended Fuel	3.35E-04	6.08E-04
Cofire 2		1.45E-04	3.74E-04
Cofire 3		1.37E-04	5.06E-04
Baseline Averages		5.45E-04 ± 6.21E-05	2.17E-03 ± 9.11E-05
Cofire Averages		2.06E-04 ± 1.12 E-04	4.96E-04 ± 1.17E-04
Absolute Difference		-3.39E-04	-1.67E-03
% Difference		-62.3%	-77.1%
Statistically Significant Change?		Yes	Yes

3.3 FLYASH CHARACTERISTICS

Results of the flyash analyses are summarized in Tables 3-7 through 3-9. Changes in ash characteristics were significant. Minerals content was much lower in the cofired fuel ash. Loss on ignition was significantly higher, indicating that the woody biomass is more difficult to fully combust. Changes in carbon content or fusion temperatures of the ash were not statistically significant.

Biomass co-firing during this verification did not impact the quality of the ash with regard to fly ash TCLP metals (40 CFR 261.24). Metals content was well below the TCLP requirements for all tests as shown in Table 3-8. Ash results did not meet the Class F Requirements (C 618-05) for use in concrete for either the baseline or co-fired fuels.

Table 3-7. Ash Characteristics

Test ID	Fuel	Carbon, wt %	Silicon Dioxide, % as SiO_2	Aluminum Oxide, % as Al_2O_3	Iron Oxide, % as Fe_2O_3	Loss on Ignition	Ash Fusion Temp., °F	
							Reducing Atmosphere: Initial Deformation	Oxidizing Atmosphere: Initial Deformation
Baseline 1	100 % Coal	7.11	14.2	7.99	2.40	12.1	2,332	2,310
Baseline 2		8.34	12.9	8.48	2.48	11.3	2,188	2,328
Baseline 3		9.00	13.8	9.84	2.76	11.1	2,181	2,334
Cofire 1	Blended Fuel	8.49	7.83	3.81	1.38	16.2	2,402	2,393
Cofire 2		10.3	6.21	3.23	1.30	18.3	2,390	2,692
Cofire 3		9.57	6.13	3.01	1.25	17.9	2,388	2,005
Baseline Averages		8.15 ± 0.9	13.6 ± 0.7	8.77 ± 0.9	2.55 ± 0.2	11.5 ± 0.5	2,234 ± 85	2,324 ± 12
Cofire Averages		9.47 ± 0.9	6.72 ± 0.9	3.35 ± 0.4	1.31 ± 0.07	17.5 ± 1.1	2,393 ± 6	2,363 ± 340
% Difference		14.9%	-67.9%	-89.4%	-64.1%	41.0%	6.90%	1.68%
Statistically Significant Change?		No	Yes	Yes	Yes	Yes	No	No

Table 3-8. Ash TCLP Metals

Test ID	Fuel	Silver, mg/L	Arsenic, mg/L	Barium, mg/L	Cadmium, mg/L	Chromium, mg/L	Mercury, mg/L	Lead, mg/L	Selenium, mg/L
Baseline 1	100 % Coal	< 0.001	0.003	0.27	0.001	0.05	< 0.001	0.02	0.10
Baseline 2		< 0.001	0.008	0.21	0.002	0.06	< 0.001	< 0.001	0.10
Baseline 3		< 0.001	0.016	0.38	0.002	0.079	0.002	< 0.001	0.14
Cofire 1	Blended Fuel	< 0.001	0.005	0.30	<0.001	0.069	<0.001	0.012	0.094
Cofire 2		< 0.001	0.004	0.37	<0.001	0.095	<0.001	0.011	0.091
Cofire 3		< 0.001	0.003	0.35	<0.001	0.096	<0.001	0.012	0.094
Baseline Averages		< 0.001	0.009	0.29	0.002	0.06	< 0.002	< 0.02	0.11
Cofire Averages		< 0.001	0.004	0.34	< 0.001	0.09	< 0.001	0.01	0.093
Limit / 40 CFR 261.24		5.0	5.0	100.0	1.0	5.0	0.2	5.0	1.0

Table 3-9. Fly Ash Class F Requirements (C 618-05)

Test ID	Fuel	Silicon Dioxide (SiO2) + Aluminum Oxide (Al2O3) + Iron Oxide (Fe2O3), (%)	Sulfur Trioxide (SO3), (%)	Loss on ignition, (%)
Baseline 1	100 % Coal	24.63	14.21	12.13
Baseline 2		23.82	18.12	11.32
Baseline 3		26.42	19.58	11.12
Cofire 1	Blended Fuel	13.02	10.15	16.24
Cofire 2		10.74	11.35	18.25
Cofire 3		10.39	10.27	17.92
Class F Requirements		70.0 (min %)	5.0 (max %)	6.0 (max %)
Baseline Averages		24.96	17.30	11.52
Cofire Averages		11.38	10.59	17.47
Absolute Difference		-13.57	-6.71	5.95
% Difference		-74.7%	-48.1%	41.0%

3.4 SUSTAINABILITY ISSUES

Table 3-1 summarized the composition of the site's coal supply and the blended fuel. Regarding use and or disposal of fly ash, biomass co-firing did not impact either sustainability issue since the quality of the ash with regard to fly ash TCLP metals and Class F Requirements was unchanged. The following is a brief GHG sustainability analysis for use of the woody biomass fuel at this site.

3.4.1 GHG Emission Offsets

Energy Used and Associated CO_2 Emissions to Harvest, Process, and Shred Wood-Based Fuel

The woody biomass fuel used at REC has a significant level of energy use and associated CO_2 emissions to harvest, process, and shred the timber prior to transportation to the site. However, since the woody biomass used at REC comes from such a wide variety of suppliers, both geographically and organizationally, estimation of this portion of the GHG offset analysis was well beyond the scope of this project, and therefore not considered here.

Transportation Fuel Use

The REC receives woody biomass based fuel from the neighboring Blandin Mill and a wide variety of commercial suppliers throughout the northern plains region. During the first 6 months of 2007, the facility received a total of approximately 173,000 tons of woody biomass based fuel. Of that, approximately 83,000 tons came from the Blandin Mill, and the remaining 90,000 tons were purchased from commercial providers. Appendix D summarizes the woody biomass deliveries to the REC during this period.

Fuel and emissions associated with transportation of woody biomass to the Blandin Mill are not considered in this analysis since the woody biomass is transported to the facility whether used as fuel or not. The data in Appendix D show that approximately 33,000 gallons of diesel fuel was used to transport woody biomass based fuels from commercial suppliers to the REC (equating to an estimated 0.37 gallons per ton of woody biomass delivered). The analysis assumes trucks using 350 Cummins motors or equivalent were used to transport the fuel at an estimated fuel economy of 6.5 miles per gallon.

<u>CO_2 Emissions From Transportation Fuel Use</u>

Based on an Energy Information Administration emission factor of 19.564 lbs CO_2/gallon, CO_2 emissions per ton of woody biomass based fuel transported to the facility are:

- 7.2 lbs CO_2 / ton woody biomass (0.37 gal fuel /ton pellets * 19.564 lbs CO_2/gal).
- 648 tons CO_2 annually (7.2 lb/ton * 180,000 tons woody biomass delivered annually).

<u>CO_2 Emissions from Combustion of Bituminous Coal Compared to Woody biomass</u>

Based on data generated during this testing, the CO_2 emission rates while firing straight coal and blended fuel (at a blending rate of approximately 92 percent woody biomass by mass) were 160 and 165 lb/MMBtu, respectively. However, combustion of wood-based fuel, which is composed of biogenic carbon, emits no appreciable CO_2 emissions under international greenhouse gas accounting methods developed by the IPCC and adopted by the ICFPA [6]. By analyzing the heat content of the coal and the woody biomass, the total boiler heat input for the test periods, and boiler efficiency, it was determined that approximately 90 percent of the heat generated during co-firing test periods is attributable to the wood-based fuel. It is therefore estimated that the CO_2 emissions offset during this testing is approximately 90 percent, or 148 lb/MMBtu at this co-firing blend.

REC Boiler 5 typically operates around 220 MMBtu/hr heat generating rate. Assuming an availability and utilization rate of 75 percent for Boiler 5 at this heat rate, this would equate to estimated annual CO_2 emission reductions of approximately 107,000 tons per year. CO_2 offsets from use of wood pellets could be even greater had the analysis included emissions associated with coal mining and transportation, but this type of complex analysis was not included in the scope of this study.

4.0 DATA QUALITY ASSESSMENT

4.1 DATA QUALITY OBJECTIVES

Under the ETV program, Southern specifies data quality objectives (DQOs) for each primary verification parameter before testing commences as a statement of data quality. The DQOs for this verification were developed based on input from EPA's ETV QA reviewers, and input from the BCSG. Test results which meet the DQOs provide an acceptable level of data quality for technology users and decision makers.

The DQOs for this verification are qualitative in that the verification produced emissions performance data that satisfy the QC requirements contained in the EPA Reference Methods specified for each pollutant, and the fuel and fly ash analyses meet the quality assurance / quality control (QA/QC) requirements contained in the ASTM Methods being used.

This verification did not include a stated DQO for boiler efficiency determinations because measurement accuracy validation for certain boiler parameters was not possible. Section 4.1.3 provides further discussion.

4.1.1 Emissions Testing QA/QC Checks

Each of the EPA Reference Methods used here for emissions testing contains rigorous and detailed calibrations, performance criteria, and other types of QA/QC checks. For instrumental methods using gas analyzers, these performance criteria include analyzer span, calibration error, sampling system bias, zero drift, response time, interference response, and calibration drift requirements. Methods 5, 29, CTM040, and 202 for determination of particulates and metals also include detailed performance requirements and QA/QC checks. Details regarding each of these checks can be found in the methods and are not repeated here. However, results of certain key QA/QC checks for each method are reported as documentation that the methods were properly executed. Key emissions testing QA/QC checks are summarized in Table 4-1. Where facility CEMS were used, up to date relative accuracy test audit (RATA) certifications and quarterly cylinder gas audits (CGAs) have been procured, reviewed, and filed at Southern to document system accuracy.

The emissions testing completeness goal for this verification was to obtain valid data for 90 percent of the test periods on each boiler tested. This goal was achieved as all data was validated for the test periods.

Table 4-1. Summary of Emission Testing Calibrations and QA/QC Checks

Parameter	Calibration/QC Check	When Performed/Frequency	Allowable Result	Actual Result
CO_2,	Analyzer calibration error test	Daily before testing	± 2 % of analyzer span	All calibrations, system bias checks, and drift tests were within the allowable criteria.
	System bias checks	Before each test run	± 5 % of analyzer span	
	System calibration drift test	After each test run	± 3 % of analyzer span	
NO_X, CO, SO_2, O_2	Relative accuracy test audit	Annually (last RATA April 17, 2006)	± 20 percent of reference method	Relative accuracies for NO_X, CO, SO_2, and O_2 CEMS were 11.7, 3.0, 1.0, and 0.2 percent, respectively
TPM, Metals	Percent isokinetic rate	After each test run	90 - 110 % for TPM and metals	All criteria were met for the TPM and metals measurement and analytical systems.
	Analytical balance calibration	Daily before analyses	± 0.0002 g	
	Filter and reagent blanks	Once during testing after first test run	< 10 % of particulate catch for first test run	
	Sampling system leak test	After each test	<0.02 cfm	
	Dry gas meter calibration	Once before and once after testing	± 5 %	
	Sampling nozzle calibration	Once for each nozzle before testing	± 0.01 in.	
Metals	ICP/CVAAS	Spike and recovery of prepared QC standards	± 25% of expected value	All matrix spike and recovery results were within 90 to 110 percent of the standards, including an independent Hg audit sample
HCl, HF	Sampling system leak test	After each test	<0.02 cfm	All criteria were met for the acid gases measurement and analytical systems.
	Dry gas meter calibration	Once before and once after testing	± 5 %	
	Ion chromatograph	Analysis of prepared QC standards	± 10% of expected value	

4.1.2 Fly ash and Fuel Analyses QA/QC Checks

The laboratory selected for analysis of collected fuel and fly ash samples (Wyoming Analytical Laboratory Services, Inc.) operates under an internal quality assurance protocol, a copy of which is maintained at Southern. Each of the analytical procedures used here include detailed procedures for instrument calibration and sample handling. They also include QA/QC checks in the form of analytical repeatability requirements or matrix spike analyses. All of the QA/QC checks specified in the methods were met during these analyses.

4.1.3 Boiler Efficiency QA/QC Checks

Table 4-2 summarizes the contributing measurements for boiler efficiency determination, measurement quality objectives (MQOs) for each, and the primary method of evaluating the MQOs. Factory calibrations, sensor function checks, and reasonableness checks in the field were used to assess achievement of the MQOs where possible. Some of the MQOs were either not met or impossible to verify, so the overall uncertainty of the boiler efficiency determinations is unclear. In anticipation of this, the test plan did not specify a DQO for boiler efficiency.

Table 4-2. Boiler Efficiency QA/QC Checks

Measurement / Instrument	QA/QC Check	When Performed	MQO	Results achieved
Fuel temperature, °F	NIST-traceable calibration	Upon purchase and every 2 years	± 6 °F	Fuel temp ± 1°F Flue gas temp ± 5°F
Flue gas temperature at air heater inlet, °F				
Air temperature, °F	NIST-traceable calibration		± 1 °F	± 1°F
Moisture in air, lb/lb dry air	NIST-traceable calibration		± 3.5 %	± 3.0 %
Combustion air temperature, °F	Cross check with NIST-traceable standard	Annually	± 6 °F	Within 5°F
Steam flow, MMBtu/h or lb/h	Orifice calibration	Upon installation	± 5 % reading	Calibration not available
Steam pressure, psig	Cross check with NIST-traceable standard	Annually	± 5 psig	± 6 psig
Steam temperature, °F			± 6 °F	± 10 °F
Supply water pressure, psig			± 5 psig	Calibrations not available
Supply water temperature, °F			± 2 % of reference standard	
Fuel feed rate, lb/h	Cross check with boiler efficiency calculations	Annually	± 5 % reading	Invalidated for coal scales, but not used for determining efficiency
Fuel ultimate analyses, both wood and coal	ASTM D1945 duplicate sample analysis and repeatability	2 samples	Within D1945 repeatability limits for each fuel component	Method repeatability criteria were met
Fuel heating value, Btu/lb	ASTM D1945 duplicate sample analysis and repeatability		Within D1945 repeatability limits for each fuel component	

4.1.4 Technical Systems Audit

A technical systems audit was conducted during the week of March 26-30, 2007 at the REC facility in support of this verification. The audit was conducted in accordance with SRI's recently drafted

ETV/ESTE project QA guideline. The audit was conducted remotely by the quality assurance manager, Eric Ringler, with the assistance of project staff member, Sarah Fisher, in the field.

Prior to the audit, the QAM developed an audit check-matrix listing each measurement to be conducted and the audit criteria to be examined. Before leaving for the field, the QAM and field technician went through the check-matrix and audit procedures to ensure good coordination of the audit. The field technician examined the check matrix to verify it was consistent with the TQAP and with expected field conditions. She also determined key test parameters for the audit. According to the project QA guideline, an audit is considered complete if all key measurements are audited and spot checks conducted for the remaining measurements.

During field measurements, the QAM and field technician discussed audit progress and findings on a daily basis by telephone. One deviation from the test plan was noted. Ash samples were collected from the ESP hopper instead of directly from the stack. The impact of this on data quality is unknown, but considered to be minor, since ash composition is an ancillary measurement and not one of the verification parameters. There is some concern about the representativeness of the samples. A corrective action report was completed.

Apart from this, all audit criteria were satisfied for all key and other audited parameters. The audit was very thorough and went well beyond the minimum required for a successful audit. The completed check-matrix and corrective action report is documented at Southern.

5.0 REFERENCES

[1] Southern Research Institute, *Test and Quality Assurance Plan – Environmental and Sustainable Technology Evaluation – Biomass Co-firing in Industrial Boilers,* www.sri-rtp.com, Southern Research Institute, Research Triangle Park, NC. October 2006.

[2] Babcock & Wilcox, *Steam –Its Generation and Use – 40th Edition,* The Babcock & Wilcox Company, Barberton, Ohio, 1992.

[3] Code of Federal Regulations (Title 40 Part 60, Appendix A) *Test Methods (Various)*, http://www.gpoaccess.gov/cfr/index.html, U.S. Environmental Protection Agency, Washington, DC, 2005.

[4] U.S. EPA, *AP-42, Compilation of Air Pollutant Emission Factors, http://www.epa.gov/oms/ap42.htm,* U.S. Environmental Protection Agency Office of Transportation and Air Quality, Washington D.C., 2005.

[5] Code of Federal Regulations (Title 40 Part 261.24) *Identification and Listing of Hazardous Waste – Toxicity Characteristic*, http://www.access.gpo.gov/nara/cfr/waisidx_05/40cfr261_05.html, U.S. Environmental Protection Agency, Washington, DC, 2005.

[6] The Climate Change Working Group of The International Council of Forest and Paper Associations (ICFPA) *Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills, Version 1.1,* National Council for Air and Stream Improvement, Inc. (NCASI), Research Triangle Park, NC, July, 2005.

Appendix A

Unit 5 Emissions Data

PARTICULATE TEST RESULTS SUMMARY

Company: Minnesota Power
Plant: Grand Rapid, MN
Unit: Boiler 5 Outlet Duct

Test Run Number	**1**	**2**	**3**	**Average**
Source Condition	Coal	Coal	Coal	
Date	03/28/2007	03/28/2007	03/28/2007	
Start Time	9:44	12:47	15:54	
End Time	12:12	15:14	18:22	
Total Particulate:				
grains/dscf	0.0165	0.0159	0.0225	0.0183
lb/hr	8.741	8.432	11.214	9.462
Filterable PM:				
grains/dscf	0.0025	0.0024	0.0029	0.0026
lb/hr	1.310	1.266	1.461	1.346
Condensible PM (Method 202):				
grains/dscf	0.0141	0.0135	0.0195	0.0157
lb/hr	7.432	7.166	9.753	8.117
Stack Parameters:				
Gas Volumetric Flow Rate, acfm	109,086	109,584	103,502	107,391
Gas Volumetric Flow Rate, dscfm	61,639	61,872	58,209	60,573
Average Gas Temperature, °F	396.1	402.3	399.4	399.3
Average Gas Velocity, ft/sec	41.339	41.528	39.223	40.697
Flue Gas Moisture, percent by volume	7.9	7.3	8.0	7.8
Average Flue Pressure, in. Hg	29.77	29.77	29.77	
Barometric Pressure, in. Hg	29.79	29.79	29.79	
Average %CO_2 by volume, dry basis	12.7	12.4	12.3	12.5
Average %O_2 by volume, dry basis	7.5	7.3	7.7	7.5
Dry Molecular Wt. of Gas, lb/lb-mole	30.332	30.276	30.276	
Gas Sample Volume, dscf	99.601	96.953	89.041	
Isokinetic Variance	101.9	98.8	96.4	

Rapids Energy Center, Grand Rapids, MN
Boiler No. 5 Outlet Duact
Average Results
Tests 1 through 3
3/28/07

Parameter	Concentration (lbs/dscf)	Emissions Rate (lbs/hr)	gr/dscf	gr/acf	ug/Nm^3
Arsenic	1.10E-10	3.89E-04	7.72E-07	4.31E-07	1.766
Barium	< 9.58E-10	< 3.39E-03	< 6.70E-06	< 3.75E-06	< 15.342
Beryllium	< 7.11E-12	< 2.50E-05	< 4.98E-08	< 2.78E-08	< 0.114
Cadmium	1.66E-11	5.83E-05	1.16E-07	6.48E-08	0.266
Chromium	< 1.60E-10	< 5.62E-04	< 1.12E-06	< 6.25E-07	< 2.557
Zinc	1.55E-09	5.51E-03	1.09E-05	6.08E-06	24.908
Copper	3.78E-10	1.35E-03	2.65E-06	1.48E-06	6.061
Lead	< 3.78E-11	< 1.33E-04	< 2.64E-07	< 1.48E-07	< 0.605
Manganese	1.57E-09	5.56E-03	1.10E-05	6.16E-06	25.200
Mercury	1.95E-10	6.89E-04	1.37E-06	7.65E-07	3.131
Nickel	< 3.79E-10	< 1.33E-03	< 2.65E-06	< 1.48E-06	< 6.064
Selenium	1.85E-10	6.50E-04	1.30E-06	7.24E-07	2.966
Silver	< 2.04E-10	< 7.17E-04	< 1.43E-06	< 7.97E-07	< 3.263

METHOD 26 TEST RESULTS

Date:	03/28/2007	Condition:	Coal
Project:	Minnisota Power	Data Taken By:	MH
Location:	Outlet Duct	Fuel Factor:	
Source:	Boiler 5		

Test Number:	1	Time:	10:15-11:15
Pressure, Barometric(Hg"):....................	29.790	Carbon Dioxide Content(%):................................	12.70
Pressure, Static(H_2O"):..........................	-0.25	Oxygen Content(%):...	7.50
Pressure, Stack(Hg"):.............................	29.772	Nitrogen Content(%):...	79.80
Initial Volume (liters)..............................	6861.22	HF (mg)..	0.073
Final Volume (liters)................................	6981.31	HCl (mg)..	0.330
Meter Temperature (^{o}F)..........................	79.50		
Meter Volume (dscf)................................	4.153	HF (ppm):..	0.746
Meter Calibration (Y)...............................	1.005	HCl (ppm):..	1.850
		HF (lbs/hr):...	0.1433
		HCl (lbs/hr):...	0.648
Average Delta H (ΔH).............................	0.010	HF (lbs/MMBtu):..	0.00E+00
Dry Standard Flow Rate (dscfm):.........	61,639	HCl (lbs/MMBtu):..	0.0000

Test Number:	2	Time:	12:47-13:47
Pressure, Barometric(Hg"):....................	29.790	Carbon Dioxide Content(%):................................	12.40
Pressure, Static(H_2O"):..........................	-0.25	Oxygen Content(%):...	7.30
Pressure, Stack(Hg"):.............................	29.772	Nitrogen Content(%):...	80.30
Initial Volume (liters)..............................	6999.74	HF (mg)..	0.041
Final Volume (liters)................................	7119.82	HCl (mg)..	0.077
Meter Temperature (^{o}F)..........................	73.60		
Meter Volume (dscf)................................	4.199	HF (ppm):..	0.414
Meter Calibration (Y)...............................	1.005	HCl (ppm):..	0.427
		HF (lbs/hr):...	0.0799
		HCl (lbs/hr):...	0.150
Average Delta H (ΔH).............................	0.010	HF (lbs/MMBtu):..	0.00E+00
Dry Standard Flow Rate (dscfm): *............	61,872	HCl (lbs/MMBtu):..	0.0000

Test Number:	3	Time:	15:54-16:54
Pressure, Barometric(Hg"):....................	29.790	Carbon Dioxide Content(%):................................	12.30
Pressure, Static(H_2O"):..........................	-0.25	Oxygen Content(%):...	7.70
Pressure, Stack(Hg"):.............................	29.772	Nitrogen Content(%):...	80.00
Initial Volume (liters)..............................	7121.170	HF (mg)..	0.100
Final Volume (liters)................................	7241.190	HCl (mg)..	0.370
Meter Temperature (^{o}F)..........................	77.20		
Meter Volume (dscf)................................	4.169	HF (ppm):..	1.018
Meter Calibration (Y)...............................	1.005	HCl (ppm):..	2.066
		HF (lbs/hr):...	0.1847
		HCl (lbs/hr):...	0.683
Average Delta H (ΔH).............................	0.010	HF (lbs/MMBtu):..	0.00E+00
Dry Standard Flow Rate (dscfm):............	58,209	HCl (lbs/MMBtu):..	0.0000

Test Number:	4	Time:	17:02-18:02
Pressure, Barometric(Hg"):....................	29.790	Carbon Dioxide Content(%):................................	12.30
Pressure, Static(H_2O"):..........................	-0.25	Oxygen Content(%):...	7.70
Pressure, Stack(Hg"):.............................	29.772	Nitrogen Content(%):...	80.00
Initial Volume (liters)..............................	7241.640	HF (mg)..	0.087
Final Volume (liters)................................	7361.700	HCl (mg)..	0.330
Meter Temperature (^{o}F)..........................	78.40		
Meter Volume (dscf)................................	4.161	HF (ppm):..	0.887
Meter Calibration (Y)...............................	1.005	HCl (ppm):..	1.846
		HF (lbs/hr):...	0.1610
		HCl (lbs/hr):...	0.611
Average Delta H (ΔH).............................	0.010	HF (lbs/MMBtu):..	0.00E+00
Dry Standard Flow Rate (dscfm):............	58,209	HCl (lbs/MMBtu):..	0.0000

Average HCl lbs/hr:	0.523	Average HF lbs/hr:	0.1422
Average HCl ppm:	1.547	Average HF ppm:	0.766
Average HCl lbs/MMBtu:	0.0000	Average HF lbs/MMBtu:	0.00E+00
Average Flow Rate (dscfm)	59982		

PARTICULATE TEST RESULTS SUMMARY

Company: Minnesota Power
Plant: Grand Rapid, MN
Unit: Boiler 5 Outlet Duct

Test Run Number	1	2	3	Average
Source Condition	15% Coal & 85% Bark	15% Coal & 85% Bark	15% Coal & 85% Bark	
Date	03/29/2007	03/29/2007	03/29/2007	
Start Time	8:17	12:28	15:21	
End Time	10:49	14:56	17:48	
Total Particulate:				
grains/dscf	0.0055	0.0037	0.0032	0.0041
lb/hr	3.260	2.043	1.842	2.381
Filterable PM:				
grains/dscf	0.0017	0.0021	0.0019	0.0019
lb/hr	1.039	1.125	1.081	1.082
Condensible PM (Method 202):				
grains/dscf	0.0037	0.0017	0.0013	0.0022
lb/hr	2.221	0.918	0.761	1.300
Stack Parameters:				
Gas Volumetric Flow Rate, acfm	147,952	131,836	137,161	138,983
Gas Volumetric Flow Rate, dscfm	69,769	64,032	66,791	66,864
Average Gas Temperature, °F	457.8	444.7	446.4	449.6
Average Gas Velocity, ft/sec	56.068	49.961	51.978	52.669
Flue Gas Moisture, percent by volume	17.9	16.6	16.3	16.9
Average Flue Pressure, in. Hg	29.87	29.87	29.87	
Barometric Pressure, in. Hg	29.80	29.80	29.80	
Average %CO_2 by volume, dry basis	12.3	12.6	12.5	12.5
Average %O_2 by volume, dry basis	7.5	7.2	7.5	7.4
Dry Molecular Wt. of Gas, lb/lb-mole	30.268	30.304	30.300	
Gas Sample Volume, dscf	121.722	77.515	80.099	
Isokinetic Variance	110.0	99.0	98.0	

Rapids Energy Center, Grand Rapids, MN
Boiler No. 5 Outlet Duact
Average Results
Tests 1 through 3
3/29/07

Parameter	Concentration (lbs/dscf)	Emissions Rate (lbs/hr)	gr/dscf	gr/acf	ug/Nm^3
Arsenic	< 4.46E-11	< 1.74E-04	< 3.13E-07	< 1.49E-07	< 0.715
Barium	3.40E-10	1.33E-03	2.38E-06	1.13E-06	5.448
Beryllium	< 7.44E-12	< 2.90E-05	< 5.21E-08	< 2.48E-08	< 0.119
Cadmium	1.48E-11	5.81E-05	1.04E-07	4.95E-08	0.238
Chromium	1.04E-10	4.06E-04	7.31E-07	3.48E-07	1.673
Zinc	2.06E-09	8.02E-03	1.44E-05	6.86E-06	32.945
Copper	1.84E-10	7.16E-04	1.29E-06	6.15E-07	2.947
Lead	< 3.00E-11	< 1.17E-04	< 2.10E-07	< 1.00E-07	< 0.481
Manganese	3.49E-10	1.37E-03	2.44E-06	1.16E-06	5.591
Mercury	< 7.92E-11	< 3.10E-04	< 5.54E-07	< 2.64E-07	< 1.268
Nickel	< 1.63E-10	< 6.34E-04	< 1.14E-06	< 5.40E-07	< 2.604
Selenium	< 7.44E-11	< 2.90E-04	< 5.21E-07	< 2.48E-07	< 1.192
Silver	< 8.41E-11	< 3.27E-04	< 5.89E-07	< 2.81E-07	< 1.347

METHOD 26 TEST RESULTS

Date:	03/29/2007	Condition:	Boimass
Project:	Minnisota Power	Data Taken By:	MH
Location:	Outlet Duct	Fuel Factor:	
Source:	Boiler 5		

Test Number:	1	Time:	8:17-9:17
Pressure, Barometric(Hg"):	29.800	Carbon Dioxide Content(%):	12.30
Pressure, Static(H_2O"):	1.00	Oxygen Content(%):	7.50
Pressure, Stack(Hg"):	29.874	Nitrogen Content(%):	80.20
Initial Volume (liters)	7363.16	HF (mg)	0.055
Final Volume (liters)	7483.34	HCl (mg)	0.100
Meter Temperature (°F)	85.50		
Meter Volume (dscf)	4.112	HF (ppm):	0.567
Meter Calibration (Y)	1.005	HCl (ppm):	0.566
		HF (lbs/hr):	0.1234
		HCl (lbs/hr):	0.224
Average Delta H (ΔH)	0.010	HF (lbs/MMBtu):	0.00E+00
Dry Standard Flow Rate (dscfm):	69,769	HCl (lbs/MMBtu):	0.0000

Test Number:	2	Time:	12:28-13:28
Pressure, Barometric(Hg"):	29.800	Carbon Dioxide Content(%):	12.60
Pressure, Static(H_2O"):	1.00	Oxygen Content(%):	7.20
Pressure, Stack(Hg"):	29.874	Nitrogen Content(%):	80.20
Initial Volume (liters)	7484.5	HF (mg)	0.026
Final Volume (liters)	7604.57	HCl (mg)	0.067
Meter Temperature (°F)	78.50		
Meter Volume (dscf)	4.162	HF (ppm):	0.265
Meter Calibration (Y)	1.005	HCl (ppm):	0.375
		HF (lbs/hr):	0.0529
		HCl (lbs/hr):	0.136
Average Delta H (ΔH)	0.010	HF (lbs/MMBtu):	0.00E+00
Dry Standard Flow Rate (dscfm): *	64,032	HCl (lbs/MMBtu):	0.0000

Test Number:	3	Time:	15:21-16:21
Pressure, Barometric(Hg"):	29.800	Carbon Dioxide Content(%):	12.50
Pressure, Static(H_2O"):	1.00	Oxygen Content(%):	7.50
Pressure, Stack(Hg"):	29.874	Nitrogen Content(%):	80.00
Initial Volume (liters)	7606.800	HF (mg)	0.023
Final Volume (liters)	7726.800	HCl (mg)	0.085
Meter Temperature (°F)	79.20		
Meter Volume (dscf)	4.154	HF (ppm):	0.235
Meter Calibration (Y)	1.005	HCl (ppm):	0.476
		HF (lbs/hr):	0.0489
		HCl (lbs/hr):	0.181
Average Delta H (ΔH)	0.010	HF (lbs/MMBtu):	0.00E+00
Dry Standard Flow Rate (dscfm):	66,791	HCl (lbs/MMBtu):	0.0000

*Based on detection limit

Average HCl lbs/hr:	0.181	Average HF lbs/hr:	0.0751
Average HCl ppm:	0.472	Average HF ppm:	0.356
Average HCl lbs/MMBtu:	0.0000	Average HF lbs/MMBtu:	0.00E+00
Average Flow Rate (dscfm)	66864		

Appendix B

Fuel and Ash Analyses

Kelley to insert pdf files in final report

Appendix C

Boiler Efficiency Determinations

Combustion Calculations - Btu Method

	INPUT CONDITIONS - BY TEST OR SPECIFICATION	
1	Excess air: at burner/leaving boiler/econ, % by weight	25.0
2	Entering air temperature, F	41.67
3	Reference temperature, F	80
4	Fuel temperature, F	66
5	Air temperature leaving air heater, F	352.11
6	Flue gas temperature leaving (excluding leakage), F	844.47
7	Moisture in air, lb/lb dry air	0.0035
8	Additional moisture, lb/100 lb fuel	0
9	Residue leaving boiler/economizer, % Total	85
10	Output, 1,000,000 Btu/h (MMBtu/h)	220.45
11	Additional theoretical air, lb/10,000 Btu Table 14, Item [2	0
12	CO_2 from sorbent, lb/10,000 Btu Table 14, Item [19]	0
13	H_2O from sorbent, lb/10,000 Btu Table 14, Item [20]	0
14	Spent sorbent, lb/10,000 Btu Table 14, Item [24]	0

FUEL - Subbituminous Coal, Minnesota

15	Ultimate Analysis		16 Theo Air, lb/100 lb fuel		17 H_2O, lb/100 lb fuel	
	Constituent	% by weight	K1	[15] x K1	K2	[15] x K2
A	C	54.17	11.51	623.5		
B	S	0.33	4.32	1.4		
C	H_2	2.85	34.29	97.7	8.94	25.48
D	H_2O	23.54			1.00	23.54
E	N_2	0.93				
F	O_2	14.23	-4.32	-61.5		
G	Ash	3.95				
H	Total	100.00	Air	661.2	H_2O	49.02

18	Higher heating value (HHV), Btu/lb fuel		9,445
19	Unburned carbon loss, % fuel input		0.13
20	Theoretical air, lb/10,000 Btu	[16H] x 100 / [18]	7.000
21	Unburned carbon, % of fuel	[19] x [18] / 14,500	0.09

COMBUSTION GAS CALCULATIONS, Quantity/10,000 Btu Fuel Input

22	Theoretical air (corrected), lb/10,000 Btu	[20] - [21] x 1151 / [18] + [11]						6.990
23	Residue from fuel, lb/10,000 Btu	([15G] + [21]) x 100 / [18]						0.043
24	Total residue, lb/10,000 Btu	[23] + [14]						0.043
			A At Burners	B Infiltration	C Leaving Furnace		D Leaving Blr/Econ	
25	Excess air, % by weight		25.0	0.0		25.0		25.0
26	Dry air, lb/10,000 Btu	(1 + [25] / 100) x [22]				8.734		8.734
27	H_2O from air, lb/10,000 Btu	[26] x [7]			0.031	0.031	0.031	0.031
28	Additional moisture, lb/10,000 Btu	[8] x 100 / [18]			0.000	0.000	0.000	0.000
29	H_2O from fuel, lb/10,000 Btu	[17H] x 100 / [18]			0.519		0.519	
30	Wet gas from fuel, lb/10,000 Btu	(100 - [15G] - [21]) x 100 / [18]				1.016		1.016
31	CO_2 from sorbent, lb/10,000 Btu	[12]				0.000		0.000
32	H_2O from sorbent, lb/10,000 Btu	[13]			0.000	0.000	0.000	0.000
33	Total wet gas, lb/10,000 Btu	Summation [26] through [32]				9.781		9.781
34	Water in wet gas, lb/10,000 Btu	Summation [27] + [28] + [29] + [32]			0.550	0.550	0.550	0.550
35	Dry gas, lb/10,000 Btu	[33] - [34]				9.231		9.231
36	H_2O in gas, % in weight	100 x [34] / [33]				5.62		5.62
37	Residue, % by weight (zero if < 0.15 lbm/10KB)	[9] x [24] / [33]				0.37		0.37

EFFICIENCY CALCULATIONS, % Input from Fuel

	Losses					
38	Dry Gas, %		0.0024 [35D] x ([6] - [3])			16.94
39	Water from fuel, as fired %	Enthalpy of steam at 1 psi, T = [6]	H1 = (3.958E-5 x T + 0.4329) x T + 1062.2	1456.0		
40		Enthalpy of water at T = [3]	H2 = [3] -32	48.0		
41			[29] x ([39] - [40]) / 100			7.31
42	Moisture in air, %		0.0045 x [27D] x ([6] - [3])			0.11
43	Unburned carbon, %		[19] or [21] x 14,500 / [18]			0.13
44	Radiation and convection, %		ABMA curve, Chapter 23	based on output of plant Btu/h		1.00
45	Other, % (include manufacturers margin if applicable)					1.00
46	Sorbent net losses, % if sorbent is used		From Chapter 10, Table 14, Item [41]			0.00
47	Summation of losses, %		Summation [38] through [46]			26.48
	Credits					
48	Heat in dry air, %		0.0024 x [26D] x ([2] - [3])			-0.80
49	Heat in moisture in air, %		0.0045 x [27D] x ([2] - [3])			-0.01
50	Sensible heat in fuel, %		(H at T[4] - H at T[3]) x 100 / [18]	0.01	H @ 80 ~ 1.0	0.01
51	Other, %					0.00
52	Summation of credits, %		Summation [48] through [51]			-0.80
53	**Efficiency, %**		100 - [47] - [52]			**74.32**

	KEY PERFORMANCE PARAMETERS		Leaving Furnace	Leaving Blr/Econ
54	Input from fuel, 1,000,000 Btu/h	100 x [10] / [53]		296.6
55	Fuel rate, 1000 lb/h	1000 x [54] / [18]		31.4
56	Wet gas weight, 1000 lb/h	[54] x [33] / 10	290.1	290.1
57	Air to burners (wet), lb/10,000 Btu	(1 +[7]) x (1 + [25A] / 100) x [22]	8.765	
58	Air to burners (wet), 1000 lb/h	[54] x [57] / 10	260.0	
59	Heat available, 1,000,000 Btu/h	[54] x {([18] - 10.30 x [17H]) / [18] - 0.005		
	Ha [Btu/h] 67.27	x ([44] + [45]) + Ha at T[5] x [57] / 10,000}	295.3	
60	Heat available/lb wet gas, Btu/lb	1000 x [59] / [56]	1017.8	
61	Adiabatic flame temperature, F	From Chapter 10, Fig.3 at H = [60], % H2O = [36]	3375.0	

Combustion Calculations - Btu Method

	INPUT CONDITIONS - BY TEST OR SPECIFICATION			FUEL - Subbituminous Coal, Minnesota					
1	Excess air: at burner/leaving boiler/econ, % by weight	23.3	15	Ultimate Analysis		16 Theo Air, lb/100 lb fuel		17 H_2O, lb/100 lb fuel	
2	Entering air temperature, F	39.96		Constituent	% by weight	K1	[15] x K1	K2	[15] x K2
3	Reference temperature, F	80	A	C	54.84	11.51	631.2		
4	Fuel temperature, F	62	B	S	0.33	4.32	1.4		
5	Air temperature leaving air heater, F	357.87	C	H_2	2.92	34.29	100.1	8.94	26.10
6	Flue gas temperature leaving (excluding leakage), F	845.08	D	H_2O	23.56			1.00	23.56
7	Moisture in air, lb/lb dry air	0.004	E	N_2	1.12				
8	Additional moisture, lb/100 lb fuel	0	F	O_2	13.64	-4.32	-58.9		
9	Residue leaving boiler/economizer, % Total	85	G	Ash	3.59				
10	Output, 1,000,000 Btu/h (MMBtu/h)	225.80	H	Total	100.00	Air	673.8	H_2O	49.66
11	Additional theoretical air, lb/10,000 Btu Table 14, Item [2	0	18	Higher heating value (HHV), Btu/lb fuel					9,491
12	CO_2 from sorbent, lb/10,000 Btu Table 14, Item [19]	0	19	Unburned carbon loss, % fuel input					0.15
13	H_2O from sorbent, lb/10,000 Btu Table 14, Item [20]	0	20	Theoretical air, lb/10,000 Btu			[16H] x 100 / [18]		7.100
14	Spent sorbent, lb/10,000 Btu Table 14, Item [24]	0	21	Unburned carbon, % of fuel			[19] x [18] / 14,500		0.10

COMBUSTION GAS CALCULATIONS, Quantity/10,000 Btu Fuel Input

			A At Burners	B Infiltration	C	Leaving Furnace	D	Leaving Blr/Econ
22	Theoretical air (corrected), lb/10,000 Btu	[20] - [21] x 1151 / [18] + [11]						7.088
23	Residue from fuel, lb/10,000 Btu	([15G] + [21]) x 100 / [18]						0.039
24	Total residue, lb/10,000 Btu	[23] + [14]						0.039
25	Excess air, % by weight		23.3	0.0		23.3		23.3
26	Dry air, lb/10,000 Btu	(1 + [25] / 100) x [22]				8.739		8.739
27	H_2O from air, lb/10,000 Btu	[26] x [7]			0.035	0.035	0.035	0.035
28	Additional moisture, lb/10,000 Btu	[8] x 100 / [18]			0.000	0.000	0.000	0.000
29	H_2O from fuel, lb/10,000 Btu	[17H] x 100 / [18]			0.523		0.523	
30	Wet gas from fuel, lb/10,000 Btu	(100 - [15G] - [21]) x 100 / [18]				1.015		1.015
31	CO_2 from sorbent, lb/10,000 Btu	[12]				0.000		0.000
32	H_2O from sorbent, lb/10,000 Btu	[13]			0.000	0.000	0.000	0.000
33	Total wet gas, lb/10,000 Btu	Summation [26] through [32]				9.789		9.789
34	Water in wet gas, lb/10,000 Btu	Summation [27] + [28] + [29] + [32]			0.558	0.558	0.558	0.558
35	Dry gas, lb/10,000 Btu	[33] - [34]				9.230		9.230
36	H_2O in gas, % in weight	100 x [34] / [33]				5.70		5.70
37	Residue, % by weight (zero if < 0.15 lbm/10KB)	[9] x [24] / [33]				0.34		0.34

EFFICIENCY CALCULATIONS, % Input from Fuel

	Losses					
38	Dry Gas, %		0.0024 x [35d] x ([6] - [3])			16.95
39	Water from	Enthalpy of steam at 1 psi, T = [6]	H1 = (3.958E-5 x T + 0.4329) x T + 1062.2	1456.3		
40	fuel, as fired	Enthalpy of water at T = [3]	H2 = [3] -32	48.0		
41	%		[29] x ([39] - [40]) / 100			7.37
42	Moisture in air, %		0.0045 x [27D] x ([6] - [3])			0.12
43	Unburned carbon, %		[19] or [21] x 14,500 / [18]			0.15
44	Radiation and convection, %		ABMA curve, Chapter 23	based on output of plant Btu/h		1.00
45	Other, % (include manufacturers margin if applicable)					1.00
46	Sorbent net losses, % if sorbent is used		From Chapter 10, Table 14, Item [41]			0.00
47	Summation of losses, %		Summation [38] through [46]			26.59
	Credits					
48	Heat in dry air, %		0.0024 x [26D] x ([2] - [3])			-0.84
49	Heat in moisture in air, %		0.0045 x [27D] x ([2] - [3])			-0.01
50	Sensible heat in fuel, %		(H at T[4] - H at T[3]) x 100 / [18]	0.01	H @ 80 ~ 1.0	0.01
51	Other, %					0.00
52	Summation of credits, %		Summation [48] through [51]			-0.84
53	**Efficiency, %**		100 - [47] - [52]			**74.24**

	KEY PERFORMANCE PARAMETERS		Leaving Furnace	Leaving Blr/Econ
54	Input from fuel, 1,000,000 Btu/h	100 x [10] / [53]		304.1
55	Fuel rate, 1000 lb/h	1000 x [54] / [18]		32.0
56	Wet gas weight, 1000 lb/h	[54] x [33] / 10	297.7	297.7
57	Air to burners (wet), lb/10,000 Btu	(1 +[7]) x (1 + [25A] / 100) x [22]	8.774	
58	Air to burners (wet), 1000 lb/h	[54] x [57] / 10	266.8	
59	Heat available, 1,000,000 Btu/h	[54] x {([18] - 10.30 x [17H]) / [18] - 0.005		
	Ha [Btu/h] 68.70	x ([44] + [45]) + Ha at T[5] x [57] / 10,000}	303.0	
60	Heat available/lb wet gas, Btu/lb	1000 x [59] / [56]	1017.9	
61	Adiabatic flame temperature, F	From Chapter 10, Fig.3 at H = [60], % H2O = [36]	3350.0	

Combustion Calculations - Btu Method

	INPUT CONDITIONS - BY TEST OR SPECIFICATION			FUEL - Subbituminous Coal, Minnesota					
1	Excess air: at burner/leaving boiler/econ, % by weight	18.2	15	Ultimate Analysis		16 Theo Air, lb/100 lb fuel		17 H_2O, lb/100 lb fuel	
2	Entering air temperature, F	39.22		Constituent	% by weight	K1	[15] x K1	K2	[15] x K2
3	Reference temperature, F	80	A	C	54.44	11.51	626.6		
4	Fuel temperature, F	63	B	S	0.33	4.32	1.4		
5	Air temperature leaving air heater, F	356.57	C	H_2	2.95	34.29	101.2	8.94	26.37
6	Flue gas temperature leaving (excluding leakage), F	840.43	D	H_2O	23.85			1.00	23.85
7	Moisture in air, lb/lb dry air	0.0041	E	N_2	0.54				
8	Additional moisture, lb/100 lb fuel	0	F	O_2	13.91	-4.32	-60.1		
9	Residue leaving boiler/economizer, % Total	85	G	Ash	3.98				
10	Output, 1,000,000 Btu/h (MMBtu/h)	221.32	H	Total	100.00	Air	669.1	H2O	50.22

11	Additional theoretical air, lb/10,000 Btu Table 14, Item [2	0	18	Higher heating value (HHV), Btu/lb fuel		9,422
12	CO_2 from sorbent, lb/10,000 Btu Table 14, Item [19]	0	19	Unburned carbon loss, % fuel input		0.17
13	H_2O from sorbent, lb/10,000 Btu Table 14, Item [20]	0	20	Theoretical air, lb/10,000 Btu	[16H] x 100 / [18]	7.101
14	Spent sorbent, lb/10,000 Btu Table 14, Item [24]	0	21	Unburned carbon, % of fuel	[19] x [18] / 14,500	0.11

COMBUSTION GAS CALCULATIONS, Quantity/10,000 Btu Fuel Input

22	Theoretical air (corrected), lb/10,000 Btu	[20] - [21] x 1151 / [18] + [11]				7.088
23	Residue from fuel, lb/10,000 Btu	([15G] + [21]) x 100 / [18]				0.043
24	Total residue, lb/10,000 Btu	[23] + [14]				0.043
		A At Burners / B Infiltration	C Leaving Furnace		D Leaving Blr/Econ	
25	Excess air, % by weight	18.2 / 0.0		18.2		18.2
26	Dry air, lb/10,000 Btu	(1 + [25] / 100) x [22]		8.382		8.382
27	H_2O from air, lb/10,000 Btu	[26] x [7]	0.034	0.034	0.034	0.034
28	Additional moisture, lb/10,000 Btu	[8] x 100 / [18]	0.000	0.000	0.000	0.000
29	H_2O from fuel, lb/10,000 Btu	[17H] x 100 / [18]	0.533		0.533	
30	Wet gas from fuel, lb/10,000 Btu	(100 - [15G] - [21]) x 100 / [18]		1.018		1.018
31	CO_2 from sorbent, lb/10,000 Btu	[12]		0.000		0.000
32	H_2O from sorbent, lb/10,000 Btu	[13]	0.000	0.000	0.000	0.000
33	Total wet gas, lb/10,000 Btu	Summation [26] through [32]		9.434		9.434
34	Water in wet gas, lb/10,000 Btu	Summation [27] + [28] + [29] + [32]	0.567	0.567	0.567	0.567
35	Dry gas, lb/10,000 Btu	[33] - [34]		8.867		8.867
36	H_2O in gas, % in weight	100 x [34] / [33]		6.01		6.01
37	Residue, % by weight (zero if < 0.15 lbm/10KB)	[9] x [24] / [33]		0.39		0.39

EFFICIENCY CALCULATIONS, % Input from Fuel

	Losses				
38	Dry Gas, %	0.0024 x [35d] x ([6] - [3])			16.18
39	Water from — Enthalpy of steam at 1 psi, T = [6]	H1 = (3.958E-5 x T + 0.4329) x T + 1062.2	1454.0		
40	fuel, as fired — Enthalpy of water at T = [3]	H2 = [3] -32	48.0		
41	%	[29] x ([39] - [40]) / 100			7.49
42	Moisture in air, %	0.0045 x [27D] x ([6] - [3])			0.12
43	Unburned carbon, %	[19] or [21] x 14,500 / [18]			0.17
44	Radiation and convection, %	ABMA curve, Chapter 23	based on output of plant Btu/h		1.00
45	Other, % (include manufacturers margin if applicable)				1.00
46	Sorbent net losses, % if sorbent is used	From Chapter 10, Table 14, Item [41]			0.00
47	Summation of losses, %	Summation [38] through [46]			25.96
	Credits				
48	Heat in dry air, %	0.0024 x [26D] x ([2] - [3])			-0.82
49	Heat in moisture in air, %	0.0045 x [27D] x ([2] - [3])			-0.01
50	Sensible heat in fuel, %	(H at T[4] - H at T[3]) x 100 / [18]	0.01	H @ 80 ~ 1.0	0.01
51	Other, %				0.00
52	Summation of credits, %	Summation [48] through [51]			-0.82
53	**Efficiency, %**	100 - [47] - [52]			**74.86**

	KEY PERFORMANCE PARAMETERS		Leaving Furnace	Leaving Blr/Econ
54	Input from fuel, 1,000,000 Btu/h	100 x [10] / [53]		295.7
55	Fuel rate, 1000 lb/h	1000 x [54] / [18]		31.4
56	Wet gas weight, 1000 lb/h	[54] x [33] / 10	278.9	278.9
57	Air to burners (wet), lb/10,000 Btu	(1 +[7]) x (1 + [25A] / 100) x [22]	8.416	
58	Air to burners (wet), 1000 lb/h	[54] x [57] / 10	248.8	
59	Heat available, 1,000,000 Btu/h	[54] x {([18] - 10.30 x [17H]) / [18] - 0.005		
	Ha [Btu/h] 68.38	x ([44] + [45]) + Ha at T[5] x [57] / 10,000}	293.5	
60	Heat available/lb wet gas, Btu/lb	1000 x [59] / [56]	1052.2	
61	Adiabatic flame temperature, F	From Chapter 10, Fig.3 at H = [60], % H2O = [36]	3490.0	

Combustion Calculations - Btu Method

	INPUT CONDITIONS - BY TEST OR SPECIFICATION	
1	Excess air: at burner/leaving boiler/econ, % by weight	22.3
2	Entering air temperature, F	44.61
3	Reference temperature, F	80
4	Fuel temperature, F	62
5	Air temperature leaving air heater, F	409.77
6	Flue gas temperature leaving (excluding leakage), F	881.09
7	Moisture in air, lb/lb dry air	0.00325
8	Additional moisture, lb/100 lb fuel	0
9	Residue leaving boiler/economizer, % Total	85
10	Output, 1,000,000 Btu/h (MMBtu/h)	227.85
11	Additional theoretical air, lb/10,000 Btu Table 14, Item [2	0
12	CO_2 from sorbent, lb/10,000 Btu Table 14, Item [19]	0
13	H_2O from sorbent, lb/10,000 Btu Table 14, Item [20]	0
14	Spent sorbent, lb/10,000 Btu Table 14, Item [24]	0

FUEL - Subbituminous Coal, Minnesota

15	Ultimate Analysis		16 Theo Air, lb/100 lb fuel		17 H_2O, lb/100 lb fuel	
	Constituent	% by weight	K1	[15] x K1	K2	[15] x K2
A	C	29.57	11.51	340.3		
B	S	0.04	4.32	0.2		
C	H_2	2.78	34.29	95.4	8.94	24.87
D	H_2O	43.60			1.00	43.60
E	N_2	0.30				
F	O_2	22.06	-4.32	-95.3		
G	Ash	1.65				
H	Total	100.00	Air	340.6	H_2O	68.47

18	Higher heating value (HHV), Btu/lb fuel		8,972
19	Unburned carbon loss, % fuel input		0.29
20	Theoretical air, lb/10,000 Btu	[16H] x 100 / [18]	3.796
21	Unburned carbon, % of fuel	[19] x [18] / 14,500	0.18

COMBUSTION GAS CALCULATIONS, Quantity/10,000 Btu Fuel Input

			A At Burners	B Infiltration	C Leaving Furnace		D Leaving Blr/Econ	
22	Theoretical air (corrected), lb/10,000 Btu	[20] - [21] x 1151 / [18] + [11]						3.774
23	Residue from fuel, lb/10,000 Btu	([15G] + [21]) x 100 / [18]						0.020
24	Total residue, lb/10,000 Btu	[23] + [14]						0.020
25	Excess air, % by weight		22.3	0.0		22.3		22.3
26	Dry air, lb/10,000 Btu	(1 + [25] / 100) x [22]				4.615		4.615
27	H_2O from air, lb/10,000 Btu	[26] x [7]			0.015	0.015	0.015	0.015
28	Additional moisture, lb/10,000 Btu	[8] x 100 / [18]			0.000	0.000	0.000	0.000
29	H_2O from fuel, lb/10,000 Btu	[17H] x 100 / [18]			0.763		0.763	
30	Wet gas from fuel, lb/10,000 Btu	(100 - [15G] - [21]) x 100 / [18]				1.094		1.094
31	CO_2 from sorbent, lb/10,000 Btu	[12]				0.000		0.000
32	H_2O from sorbent, lb/10,000 Btu	[13]			0.000	0.000	0.000	0.000
33	Total wet gas, lb/10,000 Btu	Summation [26] through [32]				5.725		5.725
34	Water in wet gas, lb/10,000 Btu	Summation [27] + [28] + [29] + [32]			0.778	0.778	0.778	0.778
35	Dry gas, lb/10,000 Btu	[33] - [34]				4.947		4.947
36	H_2O in gas, % in weight	100 x [34] / [33]				13.59		13.59
37	Residue, % by weight (zero if < 0.15 lbm/10KB)	[9] x [24] / [33]				0.30		0.30

EFFICIENCY CALCULATIONS, % Input from Fuel

	Losses				
38	Dry Gas, %		0.0024 [35D] x ([6] - [3])		9.51
39	Water from	Enthalpy of steam at 1 psi, T = [6]	H1 = (3.958E-5 x T + 0.4329) x T + 1062.2	1474.4	
40	fuel, as fired	Enthalpy of water at T = [3]	H2 = [3] -32	48.0	
41	%		[29] x ([39] - [40]) / 100		10.89
42	Moisture in air, %		0.0045 x [27D] x ([6] - [3])		0.05
43	Unburned carbon, %		[19] or [21] x 14,500 / [18]		0.29
44	Radiation and convection, %		ABMA curve, Chapter 23	based on output of plant Btu/h	1.00
45	Other, % (include manufacturers margin if applicable)				1.00
46	Sorbent net losses, % if sorbent is used		From Chapter 10, Table 14, Item [41]		0.00
47	Summation of losses, %		Summation [38] through [46]		22.74
	Credits				
48	Heat in dry air, %		0.0024 x [26D] x ([2] - [3])		-0.39
49	Heat in moisture in air, %		0.0045 x [27D] x ([2] - [3])		0.00
50	Sensible heat in fuel, %		(H at T[4] - H at T[3]) x 100 / [18]	0.01 H @ 80 ~ 1.0	0.01
51	Other, %				0.00
52	Summation of credits, %		Summation [48] through [51]		-0.38
53	**Efficiency, %**		100 - [47] - [52]		**77.65**

	KEY PERFORMANCE PARAMETERS		Leaving Furnace	Leaving Blr/Econ
54	Input from fuel, 1,000,000 Btu/h	100 x [10] / [53]		293.4
55	Fuel rate, 1000 lb/h	1000 x [54] / [18]		32.7
56	Wet gas weight, 1000 lb/h	[54] x [33] / 10	168.0	168.0
57	Air to burners (wet), lb/10,000 Btu	(1 +[7]) x (1 + [25A] / 100) x [22]	4.630	
58	Air to burners (wet), 1000 lb/h	[54] x [57] / 10	135.9	
59	Heat available, 1,000,000 Btu/h	[54] x {([18] - 10.30 x [17H]) / [18] - 0.005		
	Ha [Btu/h] 81.54	x ([44] + [45]) + Ha at T[5] x [57] / 10,000}	278.5	
60	Heat available/lb wet gas, Btu/lb	1000 x [59] / [56]	1658.0	
61	Adiabatic flame temperature, F	From Chapter 10, Fig.3 at H = [60], % H2O = [36]	3375.0	

Combustion Calculations - Btu Method

	INPUT CONDITIONS - BY TEST OR SPECIFICATION			FUEL - Subbituminous Coal, Minnesota					
1	Excess air: at burner/leaving boiler/econ, % by weight	20.5	15	Ultimate Analysis		16 Theo Air, lb/100 lb fuel		17 H_2O, lb/100 lb fuel	
2	Entering air temperature, F	48.19		Constituent	% by weight	K1	[15] x K1	K2	[15] x K2
3	Reference temperature, F	80	A	C	29.01	11.51	333.9		
4	Fuel temperature, F	64	B	S	0.05	4.32	0.2		
5	Air temperature leaving air heater, F	409.77	C	H_2	2.98	34.29	102.3	8.94	26.68
6	Flue gas temperature leaving (excluding leakage), F	857.90	D	H_2O	46.02			1.00	46.02
7	Moisture in air, lb/lb dry air	0.0044	E	N_2	0.42				
8	Additional moisture, lb/100 lb fuel	0	F	O_2	20.35	-4.32	-87.9		
9	Residue leaving boiler/economizer, % Total	85	G	Ash	1.16				
10	Output, 1,000,000 Btu/h (MMBtu/h)	219.94	H	Total	100.00	Air	348.5	H_2O	72.70

11	Additional theoretical air, lb/10,000 Btu Table 14, Item [2	0	18	Higher heating value (HHV), Btu/lb fuel		8,922
12	CO_2 from sorbent, lb/10,000 Btu Table 14, Item [19]	0	19	Unburned carbon loss, % fuel input		0.36
13	H_2O from sorbent, lb/10,000 Btu Table 14, Item [20]	0	20	Theoretical air, lb/10,000 Btu	[16H] x 100 / [18]	3.906
14	Spent sorbent, lb/10,000 Btu Table 14, Item [24]	0	21	Unburned carbon, % of fuel	[19] x [18] / 14,500	0.22

COMBUSTION GAS CALCULATIONS, Quantity/10,000 Btu Fuel Input

22	Theoretical air (corrected), lb/10,000 Btu	[20] - [21] x 1151 / [18] + [11]						3.878
23	Residue from fuel, lb/10,000 Btu	([15G] + [21]) x 100 / [18]						0.015
24	Total residue, lb/10,000 Btu	[23] + [14]						0.015
			A At Burners	B Infiltration	C Leaving Furnace		D Leaving Blr/Econ	
25	Excess air, % by weight		20.5	0.0		20.5		20.5
26	Dry air, lb/10,000 Btu	(1 + [25] / 100) x [22]				4.671		4.671
27	H_2O from air, lb/10,000 Btu	[26] x [7]			0.021	0.021	0.021	0.021
28	Additional moisture, lb/10,000 Btu	[8] x 100 / [18]			0.000	0.000	0.000	0.000
29	H_2O from fuel, lb/10,000 Btu	[17H] x 100 / [18]			0.815		0.815	
30	Wet gas from fuel, lb/10,000 Btu	(100 - [15G] - [21]) x 100 / [18]				1.105		1.105
31	CO_2 from sorbent, lb/10,000 Btu	[12]				0.000		0.000
32	H_2O from sorbent, lb/10,000 Btu	[13]			0.000	0.000	0.000	0.000
33	Total wet gas, lb/10,000 Btu	Summation [26] through [32]				5.797		5.797
34	Water in wet gas, lb/10,000 Btu	Summation [27] + [28] + [29] + [32]			0.835	0.835	0.835	0.835
35	Dry gas, lb/10,000 Btu	[33] - [34]				4.962		4.962
36	H_2O in gas, % in weight	100 x [34] / [33]				14.41		14.41
37	Residue, % by weight (zero if < 0.15 lbm/10KB)	[9] x [24] / [33]				0.23		0.23

EFFICIENCY CALCULATIONS, % Input from Fuel

	Losses				
38	Dry Gas, %	0.0024 x [35d] x ([6] - [3])			9.26
39	Water from fuel, as fired % — Enthalpy of steam at 1 psi, T = [6]	H1 = (3.958E-5 x T + 0.4329) x T + 1062.2	1462.7		
40	Enthalpy of water at T = [3]	H2 = [3] -32	48.0		
41		[29] x ([39] - [40]) / 100			11.53
42	Moisture in air, %	0.0045 x [27D] x ([6] - [3])			0.07
43	Unburned carbon, %	[19] or [21] x 14,500 / [18]			0.36
44	Radiation and convection, %	ABMA curve, Chapter 23	based on output of plant Btu/h		1.00
45	Other, % (include manufacturers margin if applicable)				1.00
46	Sorbent net losses, % if sorbent is used	From Chapter 10, Table 14, Item [41]			0.00
47	Summation of losses, %	Summation [38] through [46]			23.22
	Credits				
48	Heat in dry air, %	0.0024 x [26D] x ([2] - [3])			-0.36
49	Heat in moisture in air, %	0.0045 x [27D] x ([2] - [3])			0.00
50	Sensible heat in fuel, %	(H at T[4] - H at T[3]) x 100 / [18]	0.01	H @ 80 ~ 1.0	0.01
51	Other, %				0.00
52	Summation of credits, %	Summation [48] through [51]			-0.35
53	**Efficiency, %**	100 - [47] - [52]			**77.13**

	KEY PERFORMANCE PARAMETERS		Leaving Furnace	Leaving Blr/Econ
54	Input from fuel, 1,000,000 Btu/h	100 x [10] / [53]		285.2
55	Fuel rate, 1000 lb/h	1000 x [54] / [18]		32.0
56	Wet gas weight, 1000 lb/h	[54] x [33] / 10	165.3	165.3
57	Air to burners (wet), lb/10,000 Btu	(1 +[7]) x (1 + [25A] / 100) x [22]	4.692	
58	Air to burners (wet), 1000 lb/h	[54] x [57] / 10	133.8	
59	Heat available, 1,000,000 Btu/h	[54] x {([18] - 10.30 x [17H]) / [18] - 0.005		
	Ha [Btu/h] 81.54	x ([44] + [45]) + Ha at T[5] x [57] / 10,000}	269.3	
60	Heat available/lb wet gas, Btu/lb	1000 x [59] / [56]	1628.9	
61	Adiabatic flame temperature, F	From Chapter 10, Fig.3 at H = [60], % H2O = [36]	3350.0	

Combustion Calculations - Btu Method

INPUT CONDITIONS - BY TEST OR SPECIFICATION

1	Excess air: at burner/leaving boiler/econ, % by weight	22.9
2	Entering air temperature, F	47.82
3	Reference temperature, F	80
4	Fuel temperature, F	64
5	Air temperature leaving air heater, F	400.57
6	Flue gas temperature leaving (excluding leakage), F	874.18
7	Moisture in air, lb/lb dry air	0.0055
8	Additional moisture, lb/100 lb fuel	0
9	Residue leaving boiler/economizer, % Total	85
10	Output, 1,000,000 Btu/h (MMBtu/h)	220.06
11	Additional theoretical air, lb/10,000 Btu Table 14, Item [2	0
12	CO_2 from sorbent, lb/10,000 Btu Table 14, Item [19]	0
13	H_2O from sorbent, lb/10,000 Btu Table 14, Item [20]	0
14	Spent sorbent, lb/10,000 Btu Table 14, Item [24]	0

FUEL - Subbituminous Coal, Minnesota

15 Ultimate Analysis			16 Theo Air, lb/100 lb fuel		17 H_2O, lb/100 lb fuel	
	Constituent	% by weight	K1	[15] x K1	K2	[15] x K2
A	C	29.42	11.51	338.6		
B	S	0.04	4.32	0.2		
C	H_2	2.87	34.29	98.3	8.94	25.64
D	H_2O	44.65			1.00	44.65
E	N_2	0.44				
F	O_2	20.79	-4.32	-89.8		
G	Ash	1.79				
H	Total	100.00	Air	347.3	H2O	70.29

18	Higher heating value (HHV), Btu/lb fuel		8,913
19	Unburned carbon loss, % fuel input		0.33
20	Theoretical air, lb/10,000 Btu	[16H] x 100 / [18]	3.896
21	Unburned carbon, % of fuel	[19] x [18] / 14,500	0.20

COMBUSTION GAS CALCULATIONS, Quantity/10,000 Btu Fuel Input

22	Theoretical air (corrected), lb/10,000 Btu	[20] - [21] x 1151 / [18] + [11]	3.871
23	Residue from fuel, lb/10,000 Btu	([15G] + [21]) x 100 / [18]	0.022
24	Total residue, lb/10,000 Btu	[23] + [14]	0.022

			A At Burners	B Infiltration	C Leaving Furnace		D Leaving Blr/Econ	
25	Excess air, % by weight		22.9	0.0		22.9		22.9
26	Dry air, lb/10,000 Btu	(1 + [25] / 100) x [22]				4.756		4.756
27	H_2O from air, lb/10,000 Btu	[26] x [7]			0.026	0.026	0.026	0.026
28	Additional moisture, lb/10,000 Btu	[8] x 100 / [18]			0.000	0.000	0.000	0.000
29	H_2O from fuel, lb/10,000 Btu	[17H] x 100 / [18]			0.789		0.789	
30	Wet gas from fuel, lb/10,000 Btu	(100 - [15G] - [21]) x 100 / [18]				1.100		1.100
31	CO_2 from sorbent, lb/10,000 Btu	[12]				0.000		0.000
32	H_2O from sorbent, lb/10,000 Btu	[13]			0.000	0.000	0.000	0.000
33	Total wet gas, lb/10,000 Btu	Summation [26] through [32]				5.882		5.882
34	Water in wet gas, lb/10,000 Btu	Summation [27] + [28] + [29] + [32]			0.815	0.815	0.815	0.815
35	Dry gas, lb/10,000 Btu	[33] - [34]				5.067		5.067
36	H_2O in gas, % in weight	100 x [34] / [33]				13.85		13.85
37	Residue, % by weight (zero if < 0.15 lbm/10KB)	[9] x [24] / [33]				0.32		0.32

EFFICIENCY CALCULATIONS, % Input from Fuel

	Losses				
38	Dry Gas, %		0.0024 x [35d] x ([6] - [3])		9.66
39	Water from	Enthalpy of steam at 1 psi, T = [6]	H1 = (3.958E-5 x T + 0.4329) x T + 1062.2	1470.9	
40	fuel, as fired	Enthalpy of water at T = [3]	H2 = [3] -32	48.0	
41	%		[29] x ([39] - [40]) / 100		11.22
42	Moisture in air, %		0.0045 x [27D] x ([6] - [3])		0.09
43	Unburned carbon, %		[19] or [21] x 14,500 / [18]		0.33
44	Radiation and convection, %		ABMA curve, Chapter 23	based on output of plant Btu/h	1.00
45	Other, % (include manufacturers margin if applicable)				1.00
46	Sorbent net losses, % if sorbent is used		From Chapter 10, Table 14, Item [41]		0.00
47	Summation of losses, %		Summation [38] through [46]		23.30
	Credits				
48	Heat in dry air, %		0.0024 x [26D] x ([2] - [3])		-0.37
49	Heat in moisture in air, %		0.0045 x [27D] x ([2] - [3])		0.00
50	Sensible heat in fuel, %		(H at T[4] - H at T[3]) x 100 / [18]	0.01 H @ 80 ~ 1.0	0.01
51	Other, %				0.00
52	Summation of credits, %		Summation [48] through [51]		-0.36
53	**Efficiency, %**		100 - [47] - [52]		**77.06**

KEY PERFORMANCE PARAMETERS

			Leaving Furnace	Leaving Blr/Econ
54	Input from fuel, 1,000,000 Btu/h	100 x [10] / [53]		285.6
55	Fuel rate, 1000 lb/h	1000 x [54] / [18]		32.0
56	Wet gas weight, 1000 lb/h	[54] x [33] / 10	168.0	168.0
57	Air to burners (wet), lb/10,000 Btu	(1 +[7]) x (1 + [25A] / 100) x [22]	4.782	
58	Air to burners (wet), 1000 lb/h	[54] x [57] / 10	136.6	
59	Heat available, 1,000,000 Btu/h	[54] x {([18] - 10.30 x [17H]) / [18] - 0.005		
	Ha [Btu/h] 79.26	x ([44] + [45]) + Ha at T[5] x [57] / 10,000}	270.3	
60	Heat available/lb wet gas, Btu/lb	1000 x [59] / [56]	1609.4	
61	Adiabatic flame temperature, F	From Chapter 10, Fig.3 at H = [60], % H2O = [36]	3490.0	

Appendix D

Wood Based Fuel Deliveries for Rapids Energy
(1/1/2007 – 6/30/2007

REC Wood Burn 01/01 to 06/30, 2007

VENDOR	TYPE	Total Lbs Delivered	Number of Trips	Tons Delivered	Tons/Trip	Miles From REC	gal fuel used	CO2 emitted (ton)
Ainsworth Bemidji	Bark	14,208,802	336	7,104	21.1	69	3567	35
B Nelson	Bark	3,734,940	87	1,867	21.5	116	1553	15
Cass Forest Products	Bark	6,489,660	138	3,245	23.5	53	1125	11
Cook Logging	Bark	1,310,720	24	655	27.3	40	148	1
Covington Trucking	Bark	3,636,560	76	1,818	23.9	80	935	9
Dick Walsh Forest Product	Bark	35,298,778	618	17,649	28.6	85	8082	79
Dukek Logging	Bark	10,371,620	205	5,186	25.3	95	2996	29
Erickson Mills	Chips	303,320	6	152	25.3	75	69	1
Erickson Mills	Shredded	4,022,480	78	2,011	25.8	75	900	9
Erickson Timber	Bark	12,666,820	230	6,333	27.5	131	4635	45
Hi Tech Milling	Chips	5,147,680	105	2,574	24.5	26	420	4
Northland Biomass	Bark	8,489,580	190	4,245	22.3	5	146	1
J&A Logging	Chips	552,800	12	276	23.0	48	89	1
Lonza	Bark	1,702,864	54	851	15.8	5	42	0
MR Chips	Blandin	8,741,840	163	4,371	26.8	0	0	0
MR Chips	Private	11,479,260	199	5,740	28.8	0	0	0
Muller Trucking	Bark	770,300	15	385	25.7	53	122	1
Norbord Minnesota	Bark	3,551,400	80	1,776	22.2	82	1009	10
Potlatch Lumber Co	Bark	24,731,240	465	12,366	26.6	69	4936	48
Rajala Mill	Bark	941,220	28	471	16.8	40	172	2
Rajala Mill	Chips	2,935,060	70	1,468	21.0	40	431	4
Rajala Mill	Shredded	42,160	1	21	21.1	40	6	0
Rajala Timber Co	Bark	11,697,800	259	5,849	22.6	14	558	5
Scheff Logging	Bark	3,478,670	75	1,739	23.2	29	335	3
Wagner Forest Products	Bark	3,381,740	65	1,691	26.0	26	260	3
Total				**89,844**			**32,536**	**318**
Blandin				**82,881**				
Total Wood Burn				**172,725**				

Appendix E

Dust Collector and Electrostatic Precipitator Data

Summary of Electrostatic Precipitator Voltages and Dust Collector Pressure Drop

Run ID	Dust Collector Pressure Drop (in. wc)	Panel A Voltage	Panel B Voltage	Panel C Voltage
1	-5.2	268	274	324
2	-5.2	276	308	335
3	-4.8	286	338	336
4	-8.4	287	372	335
5	-6.9	280	373	345
6	-7.4	285	370	347