Greenhouse Gas Monitoring Plan

GREENHOUSE GAS MONITORING PLAN

PREPARED IN ACCORDANCE WITH 40 CFR PART 98

Verso Escanaba, LLC
Escanaba, MI

Prepared by:

ALL4

All4 Inc.
2393 Kimberton Road
Kimberton, PA 19442

Prepared for:

Verso Escanaba. LLC
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Version 2.2

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1. INTRODUCTION

The Verso Escanaba LLC (VE) owns and operates a bleached kraft pulp and paper mill located in Escanaba, Michigan (Escanaba Mill or Mill). The Escanaba Mill is subject to the requirements of U.S. EPA's Mandatory Reporting of Greenhouse Gas (GHG) Rule that is codified at 40 CFR Part 98. The GHG reporting rule applies to facilities such as the Escanaba Mill that emit GHG in excess of 25,000 metric tons of carbon dioxide equivalent ($MTCO_2e$) annually. As of January 1, 2010, the Escanaba Mill is required to keep inventory of its annual GHG emissions, report those emissions, and provide supporting information to U.S. EPA by March 31st of the subsequent year, or any alternate reporting date promulgated by U.S. EPA. Included as part of the GHG reporting rule is a requirement to prepare and maintain a GHG Monitoring Plan.

The GHG Monitoring Plan provides specific information regarding the applicability of the GHG reporting rule to the Escanaba Mill and documents how the Mill manages its GHG inventory and reporting program. A critical component to the GHG Monitoring Plan is the identification of the quality assurance/quality control procedures (QA/QC) to be followed as part of the inventorying and reporting of data. In addition, the GHG Monitoring Plan outlines the specific methodology that the Mill will follow in the calculation of the GHG emissions. The GHG Monitoring Plan includes the following sections:

- Section 2: Escanaba Mill Description and Applicability of 40 CFR Part 98.
- Section 3: Approach to GHG Calculations.
- Section 4: Quality Assurance and Quality Control (QA/QC).
- Section 5: Process of Data Reporting and Archiving.

The Escanaba Mill has prepared this GHG Monitoring Plan to be consistent with the requirements of 40 CFR Part 98. In addition, the Escanaba Mill has reviewed guidance documents prepared by U.S. EPA to respond to industry's questions and comments related to the GHG reporting rule and incorporated the U.S. EPA guidance in the GHG Monitoring Plan as appropriate. The GHG Monitoring Plan also reflects existing Mill QA/QC documents and Mill operating practices. As necessary, the GHG Monitoring Plan will be updated and will continue to be a usable document that can be referenced by the appropriate Mill personnel to ensure that all of the inventorying, reporting, and QA/QC activities that are associated with the GHG reporting rule are completed correctly.

2. ESCANABA MILL DESCRIPTION AND APPLICABILITY OF 40 CFR PART 98

This section of the GHG Monitoring Plan provides a general description of the Escanaba Mill and discusses the applicability of the various subparts of 40 CFR Part 98. The Mill notes that additional operations at the Mill could become subject to subparts of the rule that were not promulgated as of May 30, 2014. The Escanaba Mill will update this section and other sections of the monitoring plan as future rulemaking warrants.

2.1 MILL DESCRIPTION

The Escanaba Mill is an integrated pulp and paper mill as characterized per North American Industrial Classification System (NAICS) 322121. The Mill is located in Escanaba, Delta County, Michigan. At the Escanaba Mill, paper is produced via the bleached kraft process. A list of the Mill's combustion emission units and process emission units that are subject to 40 CFR Part 98 is provided in Table 2-1. A brief description of each emission unit is provided in Section 3.

2.2 RULE APPLICABILITY

The applicability of 40 CFR Part 98 is triggered when the actual annual emissions of GHG gases from the covered sources meets or exceeds a 25,000 $MTCO_2e$ threshold. To assess a facility's GHG emissions against the 25,000 $MTCO_2e$ level, annual emissions of the six (6) GHGs for which calculation methodologies are provided in 40 CFR Part 98 must be summed. The six (6) GHGs are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), perfluorocarbons (PFCs), hydrofluorocarbons (HFCs), and sulfur hexafluoride (SF_6). Since each GHG has a different Global Warming Potential (GWP), each GHG must be normalized to the GWP of CO_2. Consequently, CH_4 emissions are multiplied by 25 and N_2O emissions are multiplied by 298 to equate to CO_2 equivalent emissions. PFCs, HFCs, and SF_6 are not expected to be released from any of the relevant VE processes that are addressed in this monitoring plan. Biogenic emissions of CO_2 are not included in the emissions total to determine applicability of 40 CFR Part 98; however, biogenic CO_2 emissions must be reported if the 25,000 $MTCO_2e$ threshold is triggered.

Table 2-1
Process and Combustion Units Subject to 40 CFR Part 98
Verso Escanaba LLC - Escanaba, MI

Table 2-1

Process and Combustion Units Subject to 40 CFR Part 98

Verso Escanaba LLC - Escanaba, MI

Emission Unit	Unit Type	Fuel Type
No. 7 Boiler	Combustion	Natural Gas, Residual Fuel Oil
No. 8 Boiler	Combustion	Natural Gas, Residual Fuel Oil
No. 9 Boiler	Combustion	Bark/Wood Material, Natural Gas, Paper Cores
No. 11 Boiler	Combustion	Bituminous Coal, Bark/Wood Material, Natural Gas, TDF, WWTP Sludge, Pellet Fuel
Recovery Furnace	Process and Combustion	Black Liquor Solids, Natural Gas, Residual Fuel Oil
Lime Kiln	Process and Combustion	Make-up Chemicals, Natural Gas, Residual Fuel Oil
Thermal Oxidizer	Combustion	Natural Gas, NCG's
Miscellaneous Combustion Units	**Combustion**	**Natural Gas, Propane**
EI OMC	Combustion	Natural Gas
E3 OMC	Combustion	Natural Gas
Core Room (3)	Combustion	Natural Gas
Truck Shop	Combustion	Natural Gas
Shipping Rail West End	Combustion	Natural Gas
Shipping Rail East End	Combustion	Natural Gas
E3 Color Bldg Train Shed	Combustion	Natural Gas
E3 East Rail Behind Tech Shop	Combustion	Natural Gas
Large Rolling Equipment Repair Garage (4)	Combustion	Natural Gas
Hummers Hut	Combustion	Natural Gas
Hummers Hut Office Furnace	Combustion	Natural Gas
Construction Offices (3)	Combustion	Natural Gas
Hanging Shop Heaters (4)	Combustion	Natural Gas
Office Area Furnace	Combustion	Natural Gas
Water Heater	Combustion	Natural Gas
Office Area Furnaces (2)	Combustion	Natural Gas
Woodyard Hough Furnace	Combustion	Natural Gas
Woodyard Hough Hot Water Heater	Combustion	Natural Gas
Log Building Hot Water Heater	Combustion	Natural Gas
Log Building Furnace	Combustion	Natural Gas
Fire Hall Hanging Garage Heater	Combustion	Propane
Fire Hall Furnace	Combustion	Propane
Effluent Building Hanging Heater in Washing Garage	Combustion	Natural Gas
Effluent Building Hanging Heaters in Truck Loading Garage (2)	Combustion	Natural Gas
Greenhouse Offices Furnace (2)	Combustion	Natural Gas
Greenhouse (2)	Combustion	Natural Gas
Yard Greenhouse Heaters (2)	Combustion	Natural Gas
Yard Greenhouse Water Heater	Combustion	Natural Gas
C Clarifier Heaters (2)	Combustion	Natural Gas
Water Treatment	Combustion	Natural Gas
Unlined Area Landfill	Landfill	N/A
Phase 1 Landfill	Landfill	N/A
Phase 2 Landfill	Landfill	N/A
Phases 3-4 Landfill	Landfill	N/A
Phase 5 Landfill	Landfill	N/A
Phase 6 Landfill	Landfill	N/A
Phases 7-11 Landfill	Landfill	N/A

There are five (5) specific sections of 40 CFR Part 98 that currently apply to the Escanaba Mill:

- Subpart A - contains general provisions and definitions that apply to all industrial facilities
- Subpart C - includes requirements for combustion sources
- Subpart AA – includes requirements specific to pulp and paper mills
- Subpart TT - includes requirements specific to industrial waste landfills
- Subpart PP – includes requirements specific to suppliers of CO_2

The Escanaba Mill has reviewed 40 CFR Part 98 and determined which sections of the rule apply to the Mill. A summary of the applicable rules is listed in Table 2-2.

In addition, the following subsections have been identified as being potentially applicable to pulp and paper mills: Subpart S (Lime Manufacturing), Subpart U (Miscellaneous Uses of Carbonate), and Subpart II (Industrial Wastewater Treatment). Per §98.190(b), Subpart S does not apply to the Mill since the Lime Manufacturing Plant (LMP) source category does not apply to those LMPs located at a soda pulp mill. Per §98.210(b), Subpart U does not apply to the Mill since the source category does not apply to equipment that uses carbonates or carbonate-containing minerals that are consumed in the production of pulp and paper. Per§98.350(a), Subpart II does not apply to the Escanaba Mill as the wastewater treatment plant does not use any anaerobic processes to treat industrial wastewater at this facility.

In general, the applicability of 40 CFR Part 98 requires that the Mill quantify fossil fuel combustion-related and process-related emissions of CO_2, N_2O, and CH_4. For biomass materials that are combusted or processed, the Mill also needs to calculate the biogenic CO_2, N_2O, and CH_4 emissions. The fossil fuel and biogenic GHG emissions must be reported on a facility-wide basis, as well as on an individual emission unit(s) basis for those sources not electing to take advantage of any reporting alternatives available at §98.36(c). The individual totals of GHG must be speciated (i.e., annual tons of CO_2, N_2O, and CH_4).

Table 2-2
Applicability of 40 CFR Part 98
Verso Escanaba LLC - Escanaba, MI

Table 2-2
Applicability of 40 CFR Part 98
Verso Escanaba LLC - Escanaba, MI

Subpart	Citation	Citation Title
Subpart A - General Provisions	§98.1	Purpose and Scope
	§98.2	Who must report?
	§98.3	What are the general monitoring, reporting, recordkeeping, and verification requirements of this part?
	§98.4	Authorization and Responsibilities of the Designated Representative
	§98.5	How is the report submitted?
	§98.6	Definitions
	§98.7	What standardized methods are incorporated by reference into this part?
	§98.8	What are the compliance and enforcement provisions of this part?
Subpart C - General Stationary Fuel Combustion Sources	§98.30	Definition of the source category
	§98.31	Reporting threshold
	§98.32	GHGs to report
	§98.33	Calculating GHG emissions
	§98.34	Monitoring and QA/QC requirements
	§98.35	Procedures for estimating missing data
	§98.36	Data reporting requirements
	§98.37	Records that must be retained
	§98.38	Definitions
Subpart AA - Pulp and Paper Manufacturing	§98.270	Definition of Source Category
	§98.271	Reporting threshold
	§98.272	GHGs to report
	§98.273	Calculating GHG emissions
	§98.274	Monitoring and QA/QC requirements
	§98.275	Procedures for estimating missing data
	§98.276	Data reporting requirements
	§98.277	Records that must be retained
	§98.278	Definitions
Subpart PP - Suppliers of Carbon Dioxide	§98.420	Definition of Source Category
	§98.421	Reporting threshold
	§98.422	GHGs to report
	§98.423	Calculating CO_2 Supply
	§98.424	Monitoring and QA/QC requirements
	§98.425	Procedures for estimating missing data
	§98.426	Data reporting requirements
	§98.427	Records that must be retained
	§98.428	Definitions
Subpart TT - Industrial Waste Landfills	§98.460	Definition of Source Category
	§98.461	Reporting threshold
	§98.462	GHGs to report
	§98.463	Calculating GHG emissions
	§98.464	Monitoring and QA/QC requirements
	§98.465	Procedures for estimating missing data
	§98.466	Data reporting requirements
	§98.467	Records that must be retained
	§98.468	Definitions

3. APPROACH TO GHG CALCULATIONS

This section of the GHG Monitoring Plan describes the approach that the Mill will follow to determine and report the annual GHG emissions that are due to combustion and process sources. As part of the approach, the Mill has evaluated the ability to streamline the reporting process by using guidance and reporting options provided by U.S. EPA (e.g., aggregation of emission units). The supporting information and the calculation approach that is utilized for reporting purposes under Part 98 are identified in the following subsections.

3.1 GENERAL CO_2 CALCULATION PROCEDURES

The procedures related to determining GHG emissions include calculation methodologies for determining CO_2 emissions as well as CH_4 and N_2O emissions. For CO_2 emissions from combustion sources, there are four (4) different tiers of calculations which can be used: Tier 1, Tier 2, Tier 3, and Tier 4. The use of a particular tier is determined by the size of the emission unit, the type of fuel combusted, the use of a Continuous Emissions Monitoring System (CEMS), and to a degree, the preference of the facility. Different tiers can be used for different fuels on the same emission unit. The approach used to calculate other GHG emissions (i.e., CH_4 and N_2O) is determined based on the tier used to calculate CO_2 emissions. GHG emissions do not need to be calculated for emission units that meet the definition of portable or emergency generators/equipment as defined at 40 CFR §98.6. Additionally, GHG emissions from flares do not need to be considered per Subpart C. A brief description of each tier is provided in the following paragraphs.

The Tier 1 CO_2 calculation methodology uses a default fuel-specific high heating value (HHV), a default fuel-specific CO_2 emission factor, and an annual amount of fuel combusted. The Tier 1 calculation methodology can be used for those fuels with available default HHV and CO_2 values provided the emission unit heat input capacity is less than 250 MMBtu/hr. Tier 1 may be used for solid, gaseous, or liquid biomass fuels in a unit of any size provided default HHV and CO_2 values are listed. However, if HHV values for combusted fuels are routinely obtained at the minimum frequency established in 40 CFR Part 98, or at a greater frequency, then the Tier 1 CO_2 calculation methodology may not be used.

The Tier 2 CO_2 calculation methodology is similar to the Tier 1 approach except that HHV values are those that are specific to the facility or emission unit. The Tier 2 CO_2 calculation methodology can be used for emission units greater than 250 MMBtu/hr only if pipeline quality natural gas or distillate fuel oil is used to fire the large emission units. Tier 2 may also be used for the combustion of any type of fuel in Table C-1 provided the heat capacity of the unit is 250 mmBtu/hr or lower.

The Tier 3 CO_2 calculation methodology is a refinement on Tiers 1 and 2 and incorporates a facility/emission unit-specific measured carbon content of the fuel. The Tier 3 CO_2 calculation methodology may be used for an emission unit regardless of the heat input rating; however, if the emission unit fulfills each of the following six (6) criteria cited at §98.33(b)(4), then the Tier 4 CO_2 calculation methodology, which reflects the use of CEMS measurements, must be used:

1) The unit has a maximum rated heat input capacity greater than 250 MMBtu/hr, or if the unit combusts municipal solid waste and has a maximum rated input capacity greater than 600 tons per day of MSW.
2) The unit combusts solid fossil fuel or MSW as the primary fuel.
3) The unit has operated for more than 1,000 hours in any calendar year since 2005.
4) The unit has installed CEMS that are required either by an applicable Federal or State regulation or the unit's operating permit.
5) The installed CEMS include a gas monitor of any kind or a stack gas volumetric flow monitor, or both and the monitors have been certified, either in accordance with the requirements of 40 CFR Part 75, Part 60 of this chapter, or an applicable State continuous monitoring program.
6) The installed gas or stack gas volumetric flow rate monitors are required, either by an applicable Federal or State regulation or by the unit's operating permit, to undergo periodic quality assurance testing in accordance with either Appendix B to 40 CFR Part 75, Appendix F to 40 CFR Part 60, or an applicable State continuous monitoring program.

3.2 GENERAL CH_4 AND N_2O CALCULATION PROCEDURES

There are no specific calculation tiers associated with determining the annual emissions of CH_4 and N_2O. The calculation tier that is used for calculating emissions of CO_2 determines the equation to be used for calculating emissions of CH_4 and N_2O. In all cases for CH_4 and N_2O, U.S. EPA emission factors are used in the calculations.

3.3 CALCULATION AND REPORTING ALTERNATIVES

U.S. EPA provides calculation and reporting alternatives at §98.36(c) for certain configurations of stationary fuel combustion units. Certain facilities may be able to calculate and report GHG emissions for two (2) or more qualified units on a combined basis if the units are served by the same fuel supply line, share a monitored stack, or are each less than 250 MMBtu/hr. These reporting alternatives are discussed in detail below.

3.3.1 Aggregation of Units Approach

The Aggregation of Units alternative at §98.36(c)(1) may be utilized by facilities containing two (2) or more units, each of which has a maximum rated heat input capacity of 250 MMBtu/hr or less, provided that Tier 4 is not required or elected for any of the units and the units use the same tier for any common fuels combusted. The combustion emission units at the Escanaba Mill that may take advantage of the aggregation of units approach, in lieu of installing or maintaining fuel flow meters for each of the qualified devices, include No. 7 Boiler, No. 1 Coater, No. 3 Coater, the thermal oxidizer, and the miscellaneous small combustion sources. The Escanaba Mill will utilize the aggregation approach for the above listed emission units during periods of firing natural gas and will also utilize the aggregation approach for two (2) small miscellaneous combustion sources during periods of firing propane from tanks. Sources reporting under the Aggregation of Units Approach for Natural Gas Firing are identified as Source ID “GP 001.” Sources reporting under the Aggregation of Units Approach for Propane Firing are identified as Source ID “GP 002.” A summary of the emission units that will report GHG emissions according to the aggregation of units approach along with each unit’s heat input rating are provided in Table 3-1.

The use of the aggregation approach will be in accordance with 40 CFR §98.36(c)(1), which specifies that the same calculation tier shall be used for all aggregation of units sources. Since each of the sources aggregated as GP 001 fire pipeline-quality natural gas and routinely receive HHV data from the local natural gas distribution company at the minimum frequency specified in 40 CFR §98.34(a)(2)(i) (i.e., at least semi-annually), the Tier 2 calculation methodology will be utilized for reporting combined emissions. A summary of the specific equations that will be used to calculate GHG due to firing natural gas in GP 001 and example calculations representative for all GHG are provided in Table 3-2. For the propane-fired sources, the Tier 1 calculation methodology will be used. A summary of the specific equations that will be used to calculate GHG due to firing propane in GP 002 and example calculations representative for all GHG are provided in Table 3-3.

3.3.2 Monitored Common Stack or Duct Configuration

If two (2) or more emission units emit via a common stack or duct and a CEMS is in place to measure the mass of CO_2 emitted, the emission units exhausting into the common stack or duct may be combined. For these sources, the Tier 4 CO_2 calculation methodology applies. At the Escanaba Mill, there are currently no sources that share a common monitored stack which could report CO_2, CH_4, and N_2O emissions per the monitored common stack configuration approach.

3.3.3 Common Pipe Configuration

The common pipe configuration approach at 40 CFR §98.36(c)(3) may be utilized for emission units that are supplied a gaseous or liquid fuel via a common pipe and do not have a requirement to use a Tier 4 CO_2 calculation methodology (see Section 3.1). Although the local gas distribution company delivers natural gas to the Escanaba Mill via a single common pipeline and the readings from the local distribution company fuel billing meter qualify as quality-assured readings per U.S. EPA guidance, the Mill has elected to report qualified natural gas-fired sources according to the Aggregation of Units approach in lieu of the Common Pipe Configuration approach.

3.4 EMISSIONS UNIT INFORMATION

U.S. EPA provides calculation methodologies for stationary fuel combustion units at §98.33, for pulp and paper manufacturing process sources at §98.273, and for industrial waste landfills at §98.463. A list of the Mill's combustion emission units and process emission units that are subject to 40 CFR Part 98 was provided in Table 2-1. These emissions units are discussed in detail below.

3.4.1 No. 7 Boiler

No. 7 Boiler is fired with natural gas and residual fuel oil and has a heat input rating of 154 MMBtu/hr. Calculation of GHG emissions due to firing natural gas will be performed according to Tier 2 CO_2 calculation methodology under the Aggregation of Units Approach described in Section 3.3.1, for Source GP 001. A summary of the specific equations that will be used to calculate GHG for aggregated units along with example calculations is provided in Table 3-4.

No. 7 Boiler does not currently fire residual fuel oil, however, pursuant to the Escanaba Mill's Title V Operating Permit, the Mill is permitted to burn this fuel. **If the Mill decides to burn residual fuel oil in the future, the residual fuel oil meter will be calibrated in accordance with all GHG regulations.** Tier 3 CO_2 calculation methodology will be required for determining CO_2 emissions for residual fuel oil fired in No. 7 Boiler because the Escanaba Mill routinely performs fuel sampling and analysis for HHV for the Tier 3 calculations required for the No. 8 Boiler (§98.33(b)(1)(iv)). (A summary of the specific equations that will be used should the Mill decide to fire residual fuel oil in the No. 7 Boiler, along with example calculations for all GHG are provided in Table 3-4.

3.4.2 No. 8 Boiler

No. 8 Boiler has a heat input rating of 594 MMBtu/hr and is fired with natural gas and residual fuel oil. No. 8 Boiler meets the criteria for using the Tier 2 CO_2 calculation methodology when firing natural gas. No. 8 Boiler meets the criteria for using the Tier 3 CO_2 calculation methodology when firing residual fuel oil. The volume of each fuel used by No. 8 Boiler is measured by fuel-specific calibrated flow meters at the unit. A summary of the specific equations that will be used to calculate GHG for natural gas and residual fuel oil firing for No. 8 Boiler along with example calculations are provided in Table 3-5.

3.4.3 No. 9 Boiler

No. 9 Boiler has a heat input rating of 360 MMBtu/hr and is fired with natural gas and bark/wood material. No. 9 Boiler also has the potential to fire paper cores as a fuel source; however, at this time the Escanaba Mill does not utilize this firing scenario. No. 9 Boiler meets the criteria for using the Tier 2 CO_2 calculation methodology when firing natural gas. Although 98.33(b)(1)(iii) would allow Tier 1 to be used for bark/wood material, the Tier 2 CO_2 calculation methodology must be utilized for bark/wood material firing due to the frequency of fuel sampling and analysis for HHV, per §98.33(b)(1)(iv). The volume of natural gas used by No. 9 Boiler is measured by a fuel-specific flow meter at the unit. The Escanaba Mill tracks bark/wood material used through facility records. The biogenic CO_2 emissions from bark/wood material firing are calculated per 40 CFR §98.33(e)(2). A summary of the specific equations that will be used to calculate GHG emissions for the No. 9 Boiler along with example calculations are provided in Table 3-6.

3.4.4 No. 11 Boiler

No. 11 Boiler has a heat input rating of 1,040 MMBtu/hr and is fired with natural gas, bituminous coal, tire-derived fuel (TDF), wastewater treatment plant (WWTP) sludge, bark/wood material, and pellet fuel. Depending upon availability, operational, and economic considerations, not all of these fuels may be used at any given time.

No. 11 Boiler meets the criteria for using Tier 2 CO_2 calculation methodology when firing natural gas, bark/wood waste material, and WWTP sludge. The Tier 3 CO_2 calculation methodology will be used when firing bituminous coal and TDF. Tier 1 will be utilized for Pellet fuel combustion as long as the pellet fuel provides less than 10 percent of the boiler's annual heat input. The biogenic CO_2 emissions from bark/wood material firing are calculated per 40 CFR §98.33(e)(2). A summary of the specific equations that will be used to calculate GHG emissions for No. 11 Boiler in 2010 along with example calculations are provided in Table 3-7.

The volume of natural gas used by No. 11 Boiler is measured by a fuel-specific flow meter at the unit. The Escanaba Mill tracks bark/wood material, bituminous coal, TDF, WWTP sludge, and pellet fuel used through facility records.

3.4.5 Thermal Oxidizer

The Mill operates one (1) 20 MMBtu/hr natural gas-fired thermal oxidizer to combust non-condensable gases (NCGs) and stripper off gases (SOGs) that are produced throughout the pulping process. U.S. EPA has provided guidance that allows for the exemption of NCGs and SOGs from the requirement to calculate and report GHG emissions. However, the GHG emissions from natural gas combusted by the thermal oxidizer must still be considered. The thermal oxidizer is qualified to utilize the Aggregation of Units approach in reporting the unit's GHG emissions due to firing natural gas. A summary of the specific equations that will be used to calculate GHG for aggregated units firing natural gas (GP 001) along with example calculations are provided in Table 3-2.

3.4.6 Miscellaneous Heaters and Boilers

There are many small combustion sources at the Escanaba Mill for which GHG emissions will be calculated. Since all of these sources have a heat input less than 250 MMBtu/hr, they are qualified to utilize the Aggregation of Units approach in reporting the unit's GHG emissions for firing natural gas (GP 001) and for propane (GP 002). A summary of the specific equations that will be used to calculate GHG for aggregated units for natural gas firing, along with example calculations for all GHG are provided in Table 3-2. A summary of the specific equations that will be used to calculate GHG for aggregated units for propane firing, along with example calculations for all GHG are provided in Table 3-3. A summary of the specific equations that will be used for the miscellaneous sources when firing residual fuel oil along with example calculations are provided in Table 3-8.

3.5 SUBPART AA PULP AND PAPER CALCULATION METHODOLOGY

U.S. EPA provides calculation methodologies for pulp and paper manufacturing process sources in 40 CFR Subpart AA at §98.273. The Mill adds soda ash (Na_2CO_3) as a make-up chemical. This triggers the requirements associated with 40 CFR §98.273(d). At the Escanaba Mill, the Recovery Furnace and Lime Kiln are the two (2) emission units that are affected under 40 CFR Subpart AA.

3.5.1 Lime Kiln

The Lime Kiln fires natural gas and residual fuel oil and has a maximum rated heat input capacity of 75 MMBtu/hr. Per the requirements of Subpart AA, the Escanaba Mill will use a Tier 2 CO_2 calculation methodology to calculate natural gas emissions and the corresponding emission calculation methodology for CH_4 and N_2O. A quality assured flow meter is used to measure the amount of residual fuel oil fired in the Lime Kiln. Tier 3 CO_2 calculation methodology is used to calculate fuel oil emissions and the corresponding emission calculation methodology for CH_4 and N_2O. A summary of the specific equations that will be used for the Lime Kiln along with example calculations are provided in Table 3-9.

3.5.2 Carbonate Make-up Chemical Usage

Under Subpart AA, the amount of carbonate make-up chemical usage per year must be determined. The Mill adds soda ash (Na_2CO_3) in the lime kiln as a make-up chemical. The amount of soda ash added is tracked through facility records by accounting under 1510108179 - 100903181. Note that soda ash is also used in the digester, washing, and bleaching areas but this soda ash is not used as carbonate make-up chemical. This soda ash is tracked under 1510108181 – 100903181 but is not used to determine GHG emissions. A summary of the specific equations that will be used to calculate emissions of GHG due to carbonate make-up chemical usage is provided in Table 3-10.

3.5.3 Chemical Recovery Furnace

The Chemical Recovery Furnace at the Escanaba Mill fires spent black liquor solids (BLS) to recover pulping chemicals. For start-up, shut-down, and load stabilization, the Chemical Recovery Furnace fires residual fuel oil and natural gas. All of the CO_2 emissions from BLS firing are biogenic. Per the requirements of Subpart AA, the Escanaba Mill will use facility records and a Tier 2 CO_2 calculation for Natural Gas and a Tier 3 CO_2 calculation for Residual Fuel Oil to calculate fossil fuel-related CO_2 emissions and the corresponding methodology for CH_4 and N_2O. Quality assured flow meters are used to measure the amount BLS fired in the Chemical Recovery

Furnace. A summary of the specific calculation tiers and equations that will be used for the Chemical Recovery Furnace along with example calculations are provided in Table 3-11.

3.6 SUBPART PP SUPPLIERS OF CARBON DIOXIDE

Subpart PP applies to facilities with production process units that capture a CO_2 stream for the purposes of supplying CO_2 for a commercial application. The Escanaba Mill leases a portion of its property to a precipitated calcium carbonate (PCC) company. The PCC plant is not under common ownership or common control with the Mill operations. Equipment and processes related to the PCC plant are owned and operated by Omya Inc. The PPC plant receives process exhaust gas from the Escanaba Mill Lime Kiln, which contains CO_2. The PCC Plant captures and utilizes the CO_2 to produce PCC. The PCC is then supplied to the Mill and used in additional processes. Since under this arrangement it can be interpreted that the Mill generates a CO_2 stream and transfers at least part of it to a commercial application (i.e., PCC production), Subpart PP applies to the Mill's transfer of Lime Kiln exhaust to the PPC plant.

The appropriate monitoring will be conducted in accordance with Subpart PP. A quality assured volumetric flow sensor is used to measure the volumetric flow rate of the exhaust containing CO_2 transferred to the PPC Plant. VE will quantify the mass of CO_2 captured in accordance with §98.423(a) using Equation PP-2. Per Subpart PP, volumetric flow measurements will be corrected to standard industry temperature and pressure conditions to quantify the mass of CO_2 captured. Standard industry temperature and pressure conditions for purposes of this subpart are defined pursuant to 40 CFR Part 98.424(c) as follows: standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere. VE does not import or export CO_2 in containers, so §98.423(b) does not apply. A summary of the specific equations that will be used to calculate GHG emissions from the CO_2 captured along with example calculations are provided in Table 3-9.

3.7 SUBPART TT INDUSTRIAL WASTE LANDFILLS

U.S. EPA provides calculation methodologies for industrial waste landfills in 40 CFR Subpart TT at §98.463. At the Escanaba Mill, there are four (4) landfill units that are affected under 40 CFR

Subpart TT: an unlined area, Phase 1, Phase 2, and a landfill unit consisting of Phases 3 to 11. Phases 1 through 11 are classified as Type III Industrial Waste Landfills by the Michigan EGLE. These four (4) landfill units are equipped with passive vents, and various waste streams feed into them. These waste streams include ash from the No. 11 mixed fuel boiler; ash from the No. 9 wood and natural gas boiler; wastewater treatment plant sludge (primary and secondary combined); lime wastes from the recovery system including: green lime, white lime, grits, and dregs; wood waste, pulp and paper; construction and demolition waste; asbestos; and general mill garbage. About 300 cubic yards are disposed of in the active units daily, and quantities are measured by the number of truckloads. The Mill is not required to provide a daily cover, per the facility's plan of operations. Permanent cover is constructed once the phases are full; and partial cover is applied every five (5) to ten (10) years. A summary of the specific equations that will be used to calculate GHG emissions from each landfill unit along with example calculations are provided in Table 3-12.

3.7.1 Unlined Area

The unlined area was opened and began accepting waste in the early 1900's. It has a capacity of approximately 2.1 million cubic yards and spans approximately 52 acres. The unlined area stopped accepting waste in 1992, and in 2002 the landfill unit was closed. The Mill is not required to provide a daily cover, per the facility's plan of operations. Post closure care will be conducted through January 2024.

3.7.2 Phase 1

Phase 1 was constructed in 2002 and is currently closed. It has a double-composite liner with leachate collection and spans 7.9 acres. The Phase 1 unit has a capacity of 346,650 cubic yards and closed in 2012. The waste was disposed in the active area on a daily basis and measured by number of truckloads hauled. The Mill is not required to provide a daily cover, per the facility's plan of operations.

3.7.3 Phase 2

Phase 2 was constructed in 1991 and was closed in 1995. The landfill unit has a double-composite liner with leachate collection and spans 9.3 acres. The Phase 2 unit has a capacity of 400,000 cubic yards and does not require daily cover, per the facility's plan of operations. Post closure care will be conducted through April 2025.

3.7.4 Phases 3 through 11

Phases 3 through 11 are contiguous cells with varying characteristics and all were or will be constructed with a double-composite liner and leachate collection.

3.7.4.1 Phases 3 through 11

Phases 3 and 4 were constructed in 1992 were closed in 2015. Their combined capacity is 921,000 cubic yards spanning 16.6 acres.

3.7.4.2 Phase 5

Phase 5 is open and was constructed in year 2000 and is expected to close between the years 2014 and 2020. This cell has a capacity of 902,200 cubic yards covering 9.4 acres.

3.7.4.3 Phase 6

Phase 6 was constructed in 2011 and was licensed for operation in 2012. This cell covers eight (8) acres with a capacity of 851,800 cubic yards. Its anticipated closure is between the year 2022 and 2030.

3.7.4.4 Phase 7

Phase 7 was constructed in 2018 and was licensed for operation in 2019. This cell covers eight (8.2) acres with a capacity of 851,800 cubic yards. Its anticipated closure is between the year 2029 and 2035.

3.7.4.5 Phases 8 through 11

Phases 8 through 11 are unconstructed with a potential capacity of 3,532,900 cubic yards. Phase 11 has an estimated closure between the years 2055 and 2075.

3.8 EXEMPT SOURCES AND FUELS

The Escanaba Mill has identified several emissions units and "fuels" that are not required to be part of the GHG reporting program. Currently, the GHG rule exempts emission units that qualify as portable and as emergency back-up units. The criteria that must be met in order for a unit to be classified as "portable" or as "emergency back-up" are listed in Table 3-12.

The following subsections have been identified as being potentially applicable to pulp and paper mills: Subpart S (Lime Manufacturing), Subpart U (Miscellaneous Uses of Carbonate), and Subpart II (Industrial Wastewater Treatment). Per §98.190(b), Subpart S does not apply to the Mill since the Lime Manufacturing Plant (LMP) source category does not apply to those LMPs located at a soda pulp mill. Per §98.210(b), Subpart U does not apply to the Mill since the source category does not apply to equipment that uses carbonates or carbonate-containing minerals that are consumed in the production of pulp and paper. Per§98.350(a), Subpart II does not apply to the Escanaba Mill as the wastewater treatment plant does not use any anaerobic processes to treat industrial wastewater at this facility.

The GHG reporting rule does not require GHG emissions to be calculated for certain types of fuels. Guidance provided by U.S. EPA exempted non-condensable gases (NCGs), stripper off gases (SOGs), and concentrated vent gases (CVGs) from being included as fuels for which GHG emissions must be calculated. In addition, fuels not listed in Table C-1 of 40 CFR Part 98 that meet both of the following criteria do not need to be included:

- The fuel is fired in a combustion unit not required to utilize Tier 4 methodology, and
- For Tier 3 units, the fuel supplies less than 10% of the annual heat input to either the emissions unit or a group of emission units that are reporting according to the a common pipe configuration approach.

3.9 PROCEDURES FOR REPLACING MISSING DATA

The Escanaba Mill will use source-specific procedures for replacing missing data. Specifically, the requirements of 40 CFR §98.35 will address missing data related to stationary fuel combustion, §98.275 will address missing data associated with pulp and paper manufacturing, and §98.465 will address missing data associated with industrial waste landfills. The Escanaba Mill recognizes that missing data are often due to uncontrollable circumstances and not necessarily a failure on the part of the Mill. The missing data procedures apply to required parameters that are subject to some form of quality assurance and are used in the computation of GHG emissions.

U.S. EPA requires information to justify and explain the circumstances involving the replacement of missing data. The Mill will replace missing data in accordance with the following sections.

3.9.1 Missing Data for Stationary Fuel Combustion (Subpart C)

The missing data requirements for stationary fuel combustion apply to two (2) general types of emission units, emission units subject to or required to report following the Acid Rain Program (ARP) and emission units subject to CO_2 calculation methodologies listed at 40 CFR §98.33(a)(1)-(4). All emission units reporting GHG are subject to the missing data procedures related to 40 CFR §98.33(a)(1) through (4).

Emission units at the Escanaba Mill will use a combination of Tier 1, Tier 2, or Tier 3 CO_2 calculation methodology. The potential missing data for Tier 1, Tier 2 and Tier 3 sources are limited to High Heat Value (HHV), fuel flow rates (natural gas and liquid fuels), carbon content, and mass of solid fuels.

<u>Missing Fuel Usage Data (Subpart C)</u>

The Mill uses fuel usage data for natural gas, residual fuel oil, TDF, WWTP sludge, bark/wood material, pellet fuel, and coal as part of the approach to calculate emissions under Tiers 1, 2, and 3 calculation methodologies. For missing fuel usage data, the Mill will substitute missing data with the best available estimate of fuel usage based on all available process data. The Mill will document and retain records of the procedures used for all such estimates.

Missing HHV Data (Subpart C)

To perform Tier 2 and other calculations, the Mill receives HHV data minimally as follows:

- Natural Gas	Semi-annually
- Bark/Wood Material	Weekly Sample for Monthly Composite
- WWTP Sludge	Weekly Sample for Monthly Composite
- TDF	Weekly Sample for Monthly Composite

As specified in §98.33, if the results of fuel sampling are received less frequently than monthly, then the annual average HHV for that fuel shall be calculated as the arithmetic average HHV for all values for the year (including valid samples and substitute data values under §98.35). If the results of fuel sampling are received monthly, the Mill shall use equation C-2b to determine an annual average HHV for that fuel. If the results of fuel sampling are received more frequently than monthly, the Mill shall use Equation C-2b with a monthly arithmetic average HHV multiplied by the specific monthly fuel usage (in units of mass or volume) and then divided by the annual fuel usage (in units of mass or volume).

For each fuel specific HHV that is missing, an arithmetic average will be used as a replacement value. The arithmetic average will be calculated using the quality-assured HHV value immediately preceding and immediately following the missing data incident. If a quality-assured "after" value has not been obtained by the time that the GHG emissions report is due, the quality-assured "before" value for missing data substitution or the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours) shall be used. If no quality-assured "before" value is available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

Missing Carbon Content Data (Subpart C)

To perform Tier 3 and other calculations, the Mill receives carbon content data minimally as follows:

- Coal	Per lot from Supplier Provided Analysis
- TDF	Weekly Sample for Monthly Composite
- Fuel Oil	Monthly Sample

As specified in §98.33, if the results of any fuel sampling of carbon content required under Part 98 are received less frequently than monthly, then the annual average value for that parameter shall be calculated as the arithmetic average value for all values for the year (including valid samples and substitute data values under §98.35). If the results of the parameter are received monthly, the Mill shall use equation C-2b to determine an annual average value. If results are received more frequently than monthly, the Mill shall use Equation C-2b with a monthly arithmetic average value multiplied by the specific monthly usage and then divided by the annual fuel usage.

For each required measurement of carbon content that is missing, an arithmetic average will be used as a replacement value. The arithmetic average will be calculated using the quality-assured carbon content or molecular weight value immediately preceding and immediately following the missing data incident. If a quality-assured “after” value has not been obtained by the time that the GHG emissions report is due, the quality-assured “before” value for missing data substitution or the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours) shall be used. If no quality-assured “before” value is available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

3.9.2 Missing Data for Pulp and Paper Manufacturing (Subpart AA)

In addition to the parameters of fuel usage, HHV, carbon content, concentration of CO_2, and stack gas flow required under Subpart C, emission units at the Escanaba Mill that are regulated under 40 CFR Part 98, Subpart AA will also use black liquor analyses and carbonate make-up chemical purchase records to determine process-related GHG emissions. The potential for missing data to affect the GHG emission calculations from emission units at sources regulated under Subpart AA is relatively low. Therefore, the Mill has developed limited missing data procedures relative to Subpart AA emission units.

Missing Chemical Recovery Furnace Data (Subpart AA)

The Mill will follow the missing data procedures outlined in Subpart C for parameters related to the firing of fossil-fuel in the Chemical Recovery Furnace, and will follow the missing data procedures outlined in Subpart AA for parameters used to calculate biogenic emissions due to the firing of black liquor.

The Mill utilizes an online measurement system to measure the flow of black liquor fired in the Chemical Recovery Furnace. If a value related to the amount of liquor fired is missing, the Mill will substitute the lesser value of either the maximum mass or flow rate of the Chemical Recovery Furnace, or the maximum mass or flow rate that the measurement system can measure as specified in 40 CFR 98.275(b).

The Mill analyzes at least one (1) sample of black liquor for HHV annually, and additional analyses will likely be performed at the discretion of the Mill. As long as the one (1) required analysis is performed annually, there will be no need to consider missing analytical data for black liquor HHV. If there is missing data, refer to 40 CFR 98.275(a).

Missing Chemical Makeup Data (Subpart AA)

The Mill uses purchase records to determine the mass of carbonate make-up chemicals that are added to the Mill's pulping process. The possibility of an occurrence involving a missing purchase record involving carbonate is low as backup purchasing records are maintained by the Mill and the Mill's vendors. If records are missing, however, the Mill will follow the procedures for missing data specified in 40 CFR 98.275(c).

3.9.3 Missing Data for Suppliers of Carbon Dioxide (Subpart PP)

The missing data procedures of Subpart PP generally require that the most appropriate value be substituted using a quarterly value measured during another quarter. The Mill will follow the procedures for estimating missing data found at 40 CFR §98.425 in order to determine quarterly volumetric flow of CO_2, the concentration of the CO_2 stream, or the density of the CO_2 stream when the applicable quality assurance procedures of this subpart cannot be followed.

3.9.4 Missing Data for Industrial Waste Landfills (Subpart TT)

Subpart TT does not provide any missing data procedures for waste disposal measurements.

3.10 INFORMATION TO BE REPORTED ANNUALLY

The Escanaba Mill will provide an annual summary of GHG emissions to U.S. EPA no later than March 31st of each calendar year, or alternate reporting date promulgated by U.S. EPA, for GHG emissions associated with the previous calendar year. The information to be included in each annual report is specified at 40 CFR §98.3(c), §98.36, §98.276, §98.466 for Subparts A, C, AA, and TT respectively, and summarized in the Facility's GHG Calculation Spreadsheet Tool, which is designed according to the specifications of this Monitoring Plan and maintained separately.

Table 3-1
Sources Reporting GHG Emissions According to the Aggregation of Units Approach
Verso Escanaba LLC - Escanaba, MI

Table 3-1

Sources Reporting GHG Emissions According to the Aggregation of Units Approach

Verso Escanaba LLC - Escanaba, MI

Aggregation of Units	Source Name	Fuel Fired [a]	Maximum Rated Heat Capacity (MMBtu/hr)	CO_2 Calculation Tier
GP 001	No. 7 Boiler	Natural Gas	154 MMBtu/hr	Tier 2
	Thermal Oxidizer		~20 MMBtu/hr	Tier 2
	Miscellaneous Combustion Units [b]		~ 86 MMBtu/hr total	Tier 2
GP 002	Miscellaneous Combustion Units [b]	Propane	~ 0.5 MMBtu/hr total	Tier 1

[a] The Mill will also independently calculate and report GHG emissions resulting from firing other fuels in the combustion sources.

[b] Reference the complete list of Miscellaneous Combustion Units in Table 2-1.

Table 3-2
Aggregation of Units (GP 001) for Natural Gas Firing GHG Calculation Approach and Sample Calculations
Verso Escanaba LLC - Escanaba, MI

Table 3-2
Aggregation of Units (GP 001) for Natural Gas Firing GHG Calculation Approach and Sample Calculations [(a)]
Verso Escanaba LLC - Escanaba, MI

Cumulative Heat Input:	~260 MMBtu/hr	**Aggregation Approach:**	Yes (Natural Gas)	**CO_2 CEM Operating:**	No	**Sorbent Used:**	No
Common Pipe Approach:	No	**Common Stack:**	No	**Biogenic Emissions:**	No	**Responsible Personnel:**	See Table 5-2

GHG Calculation Approach

Fuel	Usage Units	Minimum Frequency of HHV Analysis	Minimum Frequency of Carbon Content Analysis	Biogenic	CO_2 Calculation Tier	CO_2 Calculation Equation	CH_4/N_2O Calculation Equation
Natural Gas	standard cubic feet	Semi-Annually	N/A	No	2	C-2a	C-9a

GHG Sample Calculations

Equation	Sample Calculation
C-2a	GP 001 CO_2 (metric tons) = ($1x10^{-03}$) x (annual volume of natural gas fired in GP 001) x (HHV per Eq. C-2b) x (Table C-1 Emission Factor)
C-2b	$HHV_{(annual)} = \frac{\sum_{i=1}^{n}((HHV)_i \times (Fuel)_i)}{\sum_{i=1}^{n}(Fuel)_i}$ Where: $(HHV)_{annual}$ = Weighted annual average HHV of the fuel (MMBtu per mass or volume) $(HHV)_i$ = HHV of the fuel, for month "i" $(Fuel)_i$ = Mass or volume of the fuel combusted during month "i" n = Number of months in the year that fuel is burned in the unit
C-9a	GP 001 CH_4 (metric tons) = ($1x10^{-03}$) x (annual volume of natural gas fired in GP 001) x (HHV per Eq. C-2b) x (Table C-2 Emission Factor) GP 001 N_2O (metric tons) = ($1x10^{-03}$) x (annual volume of natural gas fired in GP 001) x (HHV per Eq. C-2b) x (Table C-2 Emission Factor)
Other	Annual Volume of NatGas Fired in GP 001 (scf) = (Sum of Monthly Natural Gas Billing Meter Readings) - [(Natural Gas Fired by No. 8 Boiler) + (Natural Gas Fired by No. 9 Boiler) + (Natural Gas Fired by No. 11 Boiler) + (Natural Gas Fired by Recovery Furnace) + (Natural Gas Fired by Lime Kiln)]

[(a)] GP 001 represents all natural gas-fired sources at the Mill, excluding No. 8 Boiler, No. 9 Boiler, No. 11 Boiler, the Recovery Furnace, and the Lime Kiln.
[(b)] The natural gas company will supply HHV data to the Mill on a semi-annual basis, with at least four (4) months between analysis.

Table 3-3
Aggregation of Units (GP 002) for Propane Firing GHG Calculation Approach and Sample Calculations
Verso Escanaba LLC - Escanaba, MI

Table 3-3
Aggregation of Units (GP 002)[a] for Propane Firing GHG Calculation Approach and Sample Calculations [b]
Verso Escanaba LLC - Escanaba, MI

Heat Input: ~0.5 MMBtu/hr	**Aggregation Approach:** Yes (Propane)	**CO_2 CEM Operating:** No	**Sorbent Used:** No
Common Pipe Approach: No	**Common Stack:** No	**Biogenic Emissions:** No	**Responsible Personnel:** See Table 5-2

GHG Calculation Approach

Fuel	Usage Units	Minimum Frequency of HHV Analysis	Minimum Frequency of Carbon Content	Biogenic	CO_2 Calculation Tier	CO_2 Calculation Equation	CH_4/N_2O Calculation Equation
Propane	gallons	Not required for Tier 1 calculations as default value will be used from 40 CFR 98, Subpart C, Table C-1.	N/A	No	1	C-1	C-8

GHG Sample Calculations

Equation	Sample Calculation
C-1	$CO_{2(Propane)}$ (metric tons) = ($1x10^{-03}$) x (annual volume of Propane fired) x (Table C-1 default HHV) x (Table C-1 Emission Factor)
C-8	$CH_{4(Propane)}$ (metric tons) = ($1x10^{-03}$) x (annual volume of Propane fired) x (Table C-1 default HHV) x (Table C-2 Emission Factor) $N_2O_{(Propane)}$ (metric tons) = ($1x10^{-03}$) x (annual volume of Propane fired) x (Table C-1 default HHV) x (Table C-2 Emission Factor)

[a] GP 002 represents two (2) propane-fired sources at the Mill, refer to Table 2-1 for a list of Miscellaneous Combustion Sources.
[b] GHG emissions associated with the firing of natural gas in Miscellaneous Combustion Sources are accounted for under Aggregation of Units ID GP 001. Refer to Table 3-2A.

Table 3-4
No. 7 Boiler GHG Calculation Approach and Sample Calculations for Residual Fuel Oil
Verso Escanaba LLC - Escanaba, MI

Table 3-4
No. 7 Boiler GHG Calculation Approach and Sample Calculations for Residual Fuel Oil
Verso Escanaba LLC - Escanaba, MI

Heat Input: 154 MMBtu/hr
Aggregation Approach: Yes (Natural Gas)[a]
CO_2 CEM Operating: No
Sorbent Used: No
Common Pipe Approach: No
Common Stack: No
Biogenic Emissions: No
Responsible Personnel: See Table 5-2

GHG Calculation Approach

Fuel	Usage Units	Minimum Frequency of HHV Analysis	Minimum Frequency of Carbon Content	Biogenic	CO_2 Calculation Tier	CO_2 Calculation Equation	CH_4/N_2O Calculation Equation
Residual Fuel Oil	gallons	Per Fuel Lot	Per Fuel Lot	No	3	C-4	C-8

[a] GHG emissions associated with the firing of natural gas in the No. 7 Boiler are accounted for under Aggregation of Units ID GP 001. Refer to Table 3-2A for equations.

GHG Sample Calculations

Equation	Sample Calculation
C-4	No. 7 Boiler $CO_{2\ (Fuel\ Oil)}$ (metric tons) = (44/12) x (annual volume of residual oil fired in No. 7 Boiler) x (annual average carbon content of residual oil) x (0.001)
C-8	No. 7 Boiler $CH_{4(fuel\ oil)}$ (metric tons) = ($1x10^{-03}$) x (annual volume of fuel oil fired) x (Table C-1 default HHV) x (Table C-2 Emission Factor) No. 7 Boiler $N_2O_{(fuel\ oil)}$ (metric tons) = ($1x10^{-03}$) x (annual volume of fuel oil fired) x (Table C-1 default HHV) x (Table C-2 Emission Factor)

Table 3-5
No. 8 Boiler GHG Calculation Approach and Sample Calculations
Verso Escanaba LLC - Escanaba, MI

Table 3-5
No. 8 Boiler GHG Calculation Approach and Sample Calculations
Verso Escanaba LLC - Escanaba, MI

Heat Input: 594 MMBtu/hr
Common Pipe Approach: No
Aggregation Approach: No
Common Stack: No
CO_2 CEM Operating: No
Biogenic Emissions: No
Sorbent Used: No
Responsible Personnel: See Table 5-2

GHG Calculation Approach

Fuel	Usage Units	Minimum Frequency of HHV Analysis	Minimum Frequency of Carbon Content	Biogenic	CO_2 Calculation Tier	CO_2 Calculation Equation	CH_4/N_2O Calculation Equation
Residual Fuel Oil	gallons	Per Fuel Lot	Per Fuel Lot	No	3	C-4	C-8
Natural Gas	cubic feet	Semi-Annually	N/A	No	2	C-2a	C-9a

GHG Sample Calculations

Equation	Sample Calculation
C-2a	No. 8 Boiler $CO_{2(Natural\ Gas)}$ (metric tons) = ($1x10^{-03}$) x (annual volume of natural gas fired in No. 8 Boiler) x (HHV per Eq. C-2b) x (Table C-1 Emission Factor)
C-2b	$HHV_{(annual)} = \frac{\sum_{i=1}^{n}((HHV)_i \times (Fuel)_i)}{\sum_{i=1}^{n}(Fuel)_i}$ Where: $(HHV)_{annual}$ = Weighted annual average HHV of the fuel (MMBtu per mass or volume) $(HHV)_i$ = HHV of the fuel, for month "i" $(Fuel)_i$ = Mass or volume of the fuel combusted during month "i" n = Number of months in the year that fuel is burned in the unit
C-4	No. 8 Boiler $CO_{2\ (Fuel\ Oil)}$ (metric tons) = (44/12) x (annual volume of residual oil fired in No. 8 Boiler) x (annual average carbon content of residual oil) x (0.001)
C-8	No. 8 Boiler $CH_{4(fuel\ oil)}$ (metric tons) = ($1x10^{-03}$) x (annual volume of fuel oil fired) x (Table C-1 default HHV) x (Table C-2 Emission Factor) No. 8 Boiler $N_2O_{(fuel\ oil)}$ (metric tons) = ($1x10^{-03}$) x (annual volume of fuel oil fired) x (Table C-1 default HHV) x (Table C-2 Emission Factor)
C-9a	No. 8 Boiler $CH_{4(Natural\ Gas)}$ (metric tons) = ($1x10^{-03}$) x (annual volume of natural gas fired in No. 8 Boiler) x (annual HHV per Eq. C-2b) x (Table C-2 Emission Factor) No. 8 Boiler $N_2O_{(Natural\ Gas)}$ (metric tons) = ($1x10^{-03}$) x (annual volume of natural gas fired in No. 8 Boiler) x (annual HHV per Eq. C-2b) x (Table C-2 Emission Factor)

Table 3-6
No. 9 Boiler GHG Calculation Approach and Sample Calculations
Verso Escanaba LLC - Escanaba, MI

Table 3-6
No. 9 Boiler GHG Calculation Approach and Sample Calculations
Verso Escanaba LLC - Escanaba, MI

Heat Input: 360 MMBtu/hr	**Aggregation Approach:** No	**CO_2 CEM Operating:** No	**Sorbent Used:** No
Common Pipe Approach: No	**Common Stack:** No	**Biogenic Emissions:** Yes	**Responsible Personnel:** See Table 5-2

GHG Calculation Approach

Fuel	Usage Units	Minimum Frequency of HHV Analysis	Minimum Frequency of Carbon Content	Biogenic	CO_2 Calculation Tier	CO_2 Calculation Equation	CH_4/N_2O Calculation Equation
Bark/Wood Material [a]	short tons	Weekly Sampling for Analysis of Monthly Composite	N/A	Yes	2	C-2a	C-9a
Natural gas	cubic feet	Semi-Annually	N/A	No	2	C-2a	C-9a
Paper Cores[a], [b]	short tons	N/A	N/A	No	1	C-1	C-8

[a] Wood waste and paper mill sludge are considered "Wood and Wood Residuals" on Table C-1 of 40 CFR Part 98, Subpart C, and are considered "Biomass Fuel" on Table C-2 of 40 CFR Part 98, Subpart C.
[b] The Mill has the capability to fire paper cores, however at this time, this fuel is not fired.

GHG Sample Calculations

Equation	Sample Calculation
C-2a	No. 9 Boiler $CO_{2(per\ fuel\ type)}$ (metric tons) = ($1x10^{-03}$) x (annual mass or volume of fuel fired in No. 9 Boiler) x (HHV per Eq. C-2b) x (Table C-1 Emission Factor) for Natural Gas and Bark/Wood No. 9 Boiler Biogenic CO_2 (metric tons) = (1x10-03) x (annual mass or volume of bark/wood fired in No. 9 Boiler) x (HHV per Eq. C-2b) x (Table C-1 Emission Factor)
C-2b	$HHV_{(annual)} = \frac{\sum_{i=1}^{n}((HHV)_i \times (Fuel)_i)}{\sum_{i=1}^{n}(Fuel)_i}$ Where: $(HHV)_{annual}$ = Weighted annual average HHV of the fuel (MMBtu per mass or volume) $(HHV)_i$ = HHV of the fuel, for month "i" $(Fuel)_i$ = Mass or volume of the fuel combusted during month "i" n = Number of months in the year that fuel is burned in the unit
C-1	$CO_{2(Paper\ Cores)}$ (metric tons) = ($1x10^{-03}$) x (annual mass of paper cores) x (Table C-1 default HHV) x (Table C-1 Emission Factor)
C-8	$CH_{4(Paper\ Cores)}$ (metric tons) = ($1x10^{-03}$) x (annual mass of paper cores) x (Table C-1 default HHV) x (Table C-2 Emission Factor) $N_2O_{(Paper\ Cores)}$ (metric tons) = ($1x10^{-03}$) x (annual mass of paper cores) x (Table C-1 default HHV) x (Table C-2 Emission Factor)
C-9a	No. 9 Boiler $CH_{4(per\ fuel\ type)}$ (metric tons) = ($1x10^{-03}$) x (annual mass or volume of fuel fired in No. 9 Boiler) x (annual HHV per Eq. C-2b) x (Table C-2 Emission Factor) for Natural Gas and Bark/Wood No. 9 Boiler $N_2O_{(per\ fuel\ type)}$ (metric tons) = ($1x10^{-03}$) x (annual mass or volume of fuel fired in No. 9 Boiler) x (annual HHV per Eq. C-2b) x (Table C-2 Emission Factor)

Table 3-7
No. 11 Boiler GHG Calculation Approach and Sample Calculations
Verso Escanaba LLC - Escanaba, MI

Table 3-7
No. 11 Boiler GHG Calculation Approach and Sample Calculations
Verso Escanaba LLC - Escanaba, MI

Heat Input: 1,040 MMBtu/hr	**Aggregation Approach:** No	**CO_2 CEM Operating:** Yes[(a)]	**Sorbent Used:** No
Common Pipe Approach: No	**Common Stack:** No	**Biogenic Emissions:** Yes	**Responsible Personnel:** See Table 5-2

GHG Calculation Approach

Fuel	Usage Units	Minimum Frequency of HHV Analysis	Minimum Frequency of Carbon Content Analysis	Biogenic	CO_2 Calculation Tier	CO_2 Calculation Equation	CH_4/N_2O Calculation Equation
Bituminous Coal	short tons	Per Fuel Lot	N/A	No	3	C-3	C-10
Bark/Wood Material	short tons	Weekly Sampling for Analysis of Monthly Composite	N/A	Yes	2	C-2a	C-10
Natural Gas	cubic feet	Semi-Annually	N/A	No	2	C-2a	C-10
TDF	short tons	Weekly Sampling for Analysis of Monthly Composite	N/A	No	3	C-3	C-10
WWTP Sludge	short tons	Weekly Sampling for Analysis of Monthly Composite	N/A	Yes	2	C-2a	C-10
Pellet Fuel[(b)]	short tons	N/A	N/A	Yes	1	C-6	C-10

GHG Sample Calculations

Equation	Sample Calculation
C-3	No. 11 Boiler $CO_{2(per\ fuel\ type)}$ (metric tons) = (44/12) x (annual mass or volume of fuel fired in No. 11 Boiler) x(Annual average carbon content of solid fuel fired in No. 11 Boiler)x .91) for coal or TDF
C-10	No. 11 Boiler CH_4 (metric tons) = ($CH_{4(Natural\ Gas)}$) + ($CH_{4(Wood\ Waste)}$) + ($CH_{4(Coal)}$) + ($CH_{4(TDF)}$) + ($CH_{4(Sludge)}$) + ($CH_{4(Pellet)}$), where $CH_{4\ (Natural\ Gas)}$ = ($1x10^{-03}$) x (annual heat input from total natural gas fired) x (Table C-2 Emission Factor) $CH_{4\ (Wood\ Waste)}$ = ($1x10^{-03}$) x (annual heat input from total wood waste fired) x (Table C-2 Emission Factor) $CH_{4\ (Coal)}$ = ($1x10^{-03}$) x (annual heat input from total coal fired) x (Table C-2 Emission Factor) $CH_{4\ (TDF)}$ = ($1x10^{-03}$) x (annual heat input from total TDF fired) x (Table C-2 Emission Factor) $CH_{4\ (Sludge)}$ = ($1x10^{-03}$) x (annual heat input from total sludge fired) x (Table C-2 Emission Factor) $CH_{4\ (Pellet)}$ = ($1x10^{-03}$) x (annual heat input from bark/wood fraction of total pellet fuel fired) x (Table C-2 Emission Factor)
	No. 11 Boiler N_2O (metric tons) = ($N_2O_{(Natural\ Gas)}$) + ($N_2O_{(Wood\ Waste)}$) + ($N_2O_{(Coal)}$) + ($N_2O_{(TDF)}$) + ($N_2O_{(Sludge)}$) + ($N_2O_{(Pellet)}$), where $N_2O_{\ (Natural\ Gas)}$ = ($1x10^{-03}$) x (annual heat input from total natural gas fired) x (Table C-2 Emission Factor) $N_2O_{(Wood\ Waste)}$ = ($1x10^{-03}$) x (annual heat input from total wood waste fired) x (Table C-2 Emission Factor) $N_2O_{(Coal)}$ = ($1x10^{-03}$) x (annual heat input from total coal fired) x (Table C-2 Emission Factor) $N_2O_{(TDF)}$ = ($1x10^{-03}$) x (annual heat input from total TDF fired) x (Table C-2 Emission Factor) $N_2O_{(Sludge)}$ = ($1x10^{-03}$) x (annual heat input from total sludge fired) x (Table C-2 Emission Factor) $N_2O_{(Pellet)}$ = ($1x10^{-03}$) x (annual heat input from bark/wood fraction of total pellet fuel fired) x (Table C-2 Emission Factor)
C-2a	No. 11 Boiler Biogenic CO_2 (metric tons) = $CO_{2(Wood\ Waste)}$ + $CO_{2(Sludge)}$, where: CO_2 = (1x10-03) x (annual mass or volume of fuel fired in No. 11 Boiler) x (HHV per Eq. C-2b) x (Table C-1 Emission Factor) for Bark/Wood and Sludge.

C-1	No. 11 Boiler Biogenic CO_2 (metric tons) = $CO_{2(Pellet\ Fuel)}$, where: CO_2 = (1x10-03) x (annual mass of fuel fired in No. 11 Boiler) x (Fraction of Pellet Fuel mass that is composed of Bark/Wood material) x (HHV per Table C-1) x (Table C-1 Emission Factor) for Bark/Wood and Sludge.

[a] A CO_2 CEMS and flow meter was installed and operational on No. 11 Boiler before January 1, 2011. The facility will follow the above sampling and calculation methodologies starting in reporting year 2011.

[b] Pellet fuel is composed of a plastic component (non-biogenic) and bark/wood material (biogenic). However, pellet fuel is not a listed fuel in tables C-1 or C-2 of 40 CFR Part 98, Subpart C. As a result, the bark/wood

Table 3-8
Miscellaneous Combustion Units GHG Calculation Approach and Sample Calculations
Verso Escanaba LLC - Escanaba, MI

Table 3-8
Miscellaneous Combustion Units GHG Calculation Approach and Sample Calculations
Verso Escanaba LLC - Escanaba, MI

Heat Input:	~86 MMBtu/hr	**Aggregation Approach:**	Yes (Natural Gas, Propane)	**CO_2 CEM Operating:**	No	**Sorbent Used:**	No
Common Pipe Approach:	No	**Common Stack:**	No	**Biogenic Emissions:**	No	**Responsible Personnel:**	See Table 5-2

GHG Calculation Approach

Fuel	Usage Units	Minimum Frequency of HHV Analysis	Minimum Frequency of Carbon Content Analysis	Biogenic	CO_2 Calculation Tier	CO_2 Calculation Equation	CH_4/N_2O Calculation Equation
Fuel Oil	gallons	Not required for Tier 1 calculations as default value will be used from 40 CFR 98, Subpart C, Table C-1.	N/A	No	1	C-1	C-8
Propane[(a)]	gallons	Not required for Tier 1 calculations as default value will be used from 40 CFR 98, Subpart C, Table C-1.	N/A	No	1[(a)]	See Table 3-3	See Table 3-3
Natural Gas[(b)]	cubic feet	Semi-Annually	N/A	No	2[(b)]	See Table 3-2	See Table 3-2

[(a)] GHG emissions associated with the firing of propane in Miscellaneous Combustion Sources are accounted for under Aggregation of Units ID GP 002. Refer to Table 3-3.
[(b)] GHG emissions associated with the firing of natural gas in Miscellaneous Combustion Sources are accounted for under Aggregation of Units ID GP 001. Refer to Table 3-2.

GHG Sample Calculations

Equation	Sample Calculation
C-1	$CO_{2(Fuel\ Oil)}$ (metric tons) = $(1x10^{-03})$ x (annual volume of fuel oil fired) x (Table C-1 default HHV) x (Table C-1 Emission Factor)
C-8	$CH_{4(fuel\ oil)}$(metric tons) = $(1x10^{-03})$ x (annual volume of fuel oil fired) x (Table C-1 default HHV) x (Table C-2 Emission Factor) $N_2O_{(fuel\ oil)(}$metric tons) = $(1x10^{-03})$ x (annual volume of fuel oil fired) x (Table C-1 default HHV) x (Table C-2 Emission Factor)

Table 3-9
Lime Kiln GHG Calculation Approach and Sample Calculations
Verso Escanaba LLC - Escanaba, MI

Table 3-9
Lime Kiln GHG Calculation Approach and Sample Calculations
Verso Escanaba LLC - Escanaba, MI

Heat Input:	75 MMBtu/hr	**Aggregation Approach:**	No	**CO_2 CEM Operating:**	No	**Sorbent Used:**	No
Common Pipe Approach:	No	**Common Stack:**	No	**Biogenic Emissions:**	No	**Responsible Personnel:**	See Table 5-2

GHG Calculation Approach

Fuel	Usage Units	Minimum Frequency of HHV Analysis	Minimum Frequency of Carbon Content Analysis	Biogenic	CO_2 Calculation Tier	CO_2 Calculation Equation	CH_4/N_2O Calculation Equation
Natural Gas	cubic feet	Semi-Annually	N/A	No	2	C-2a	C-9a
Residual Fuel Oil	gallons	Per fuel lot	Per fuel lot	No	3	C-4	C-8

[a] The volume of residual fuel oil is measured using a certified flow meter. The volume of natural gas fired comes from company records. Modified in December 2010.

GHG Sample Calculations

Equation	Sample Calculation
C-2a	Lime Kiln CO_2 (metric tons) = ($1x10^{-03}$) x (annual volume of natural gas fired in Lime Kiln) x (HHV per Eq. C-2b) x (Table C-1 Emission Factor)
C-4	Lime Kiln $CO_{2\ (Fuel\ Oil)}$ (metric tons) = (44/12) x (annual volume of residual oil fired in Lime Kiln) x (annual average carbon content of residual oil) x (0.001)
C-8	Lime Kiln CH_4 (metric tons) = ($1x10^{-03}$) x (annual volume of fuel oil fired) x (Table C-1 default HHV) x (Table AA-2 Emission Factor) Lime Kiln N_2O (metric tons) = ($1x10^{-03}$) x (annual volume of fuel oil fired) x (Table C-1 default HHV) x (Table AA-2 Emission Factor)
C-9a	Lime Kiln $CH_{4(Natural\ Gas)}$ (metric tons) = ($1x10^{-03}$) x (annual volume of natural gas fired in Lime Kiln) x (annual HHV per Eq. C-2b) x (Table C-2 Emission Factor) Lime Kiln $N_2O_{(Natural\ Gas)}$ (metric tons) = ($1x10^{-03}$) x (annual volume of natural gas fired in Lime Kiln) x (annual HHV per Eq. C-2b) x (Table C-2 Emission Factor)
PP-2	$\sum_{p=1}^{4} [Q_p + D_p + C_{CO_2}] = CO_{2,p}$ Where: $CO_{2,u}$ = Annual mass of CO_2 (metric tons) through flow meter u. $C_{CO2,p}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (measured as either volume % CO_2 or weight % CO_2). Q_p = Quarterly volumetric flow rate measurement for flow meter u in quarter p (standard cubic meters). D_p = Density of CO_2 in quarter p (metric tons CO_2 per standard cubic meter) for flow meter u. p = Quarter of the year.

Table 3-10
Carbonate Purchase Make-Up Chemical GHG Calculation Approach and Sample Calculations
Verso Escanaba LLC - Escanaba, MI

Table 3-10

Carbonate Purchase Make-Up Chemical GHG Calculation Approach and Sample Calculations

Verso Escanaba LLC - Escanaba, MI

Heat Input: N/A
Common Pipe Approach: N/A

Aggregation Approach: N/A
Common Stack: N/A

CO_2 CEM Operating: N/A
Biogenic Emissions: N/A
Responsible Personnel: See Table 5-2

GHG Calculation Approach

Type of Carbonate Make-Up Chemical Purchased	Usage Units	CO_2 Calculation Tier	CO_2 Calculation Equation	CH_4/N_2O Calculation Equation
Sodium Carbonate (Na_2CO_3)	Metric Tons	N/A	AA-3	N/A

GHG Sample Calculations

Equation	Sample Calculation
AA-3	CO_2 (metric tons) = (Mass of Sodium Carbonate x 44/105.99) x 1000

Table 3-11
Recovery Furnace GHG Calculation Approach and Sample Calculations
Verso Escanaba LLC - Escanaba, MI

Table 3-11
Recovery Furnace GHG Calculation Approach and Sample Calculations
Verso Escanaba LLC - Escanaba, MI

Heat Input: 950 MMBtu/hr
Common Pipe Approach: No
Aggregation Approach: No
CO_2 CEM Operating: No
Fossil Fuels Yes
Biogenic Emissions: Yes
Sorbent Used: No
Responsible Personnel: See Table 5-2

GHG Calculation Approach

Fuel	Usage Units	Minimum Frequency of HHV Analysis	Minimum Frequency of Carbon Content Analysis	Biogenic	CO_2 Calculation Tier	CO_2 Calculation Equation	CH_4/N_2O Calculation Equation
Black Liquor Solids	short tons	Annually	N/A	Yes	N/A	AA-1	AA-1
Residual Fuel Oil	gallons	Per fuel lot	Per fuel lot	No	3	C-4	C-8
Natural Gas	cubic feet	Semi-Annually	N/A	No	2	C-2a	C-9a

[a] The volume of fossil fuel combusted by the Chemical Recovery Furnace must be directly measured.

GHG Sample Calculations

Equation	Sample Calculation
AA-1	Chemical Recovery Furnace CO_2, CH_4, or N_2O (metric tons) = (0.90718) x (mass of spent BLS combusted) x HHV(BLS) x (Table AA-1 BLS Emission Factor)
C-2a	Chemical Recovery Furnace CO_2 (metric tons) = ($1x10^{-03}$) x (annual volume of natural gas fired in GP 001) x (HHV per Eq. C-2b) x (Table C-1 Emission Factor)
C-4	Chemical Recovery Furnace $CO_{2\ (Fuel\ Oil)}$ (metric tons) = (44/12) x (annual volume of residual oil fired in Recovery Furnace) x (annual average carbon content of residual oil) x (0.001)
C-8	Chemical Recovery Furnace $CH_{4(per\ fuel\ type)}$ (metric tons) = ($1x10^{-03}$) x (annual volume of fuel fired) x (Table C-1 default HHV) x (Table C-2 Emission Factor) Chemical Recovery Furnace $N_2O_{(per\ fuel\ type)}$ (metric tons) = ($1x10^{-03}$) x (annual volume of fuel fired) x (Table C-1 default HHV) x (Table C-2 Emission Factor)
C-9a	Chemical Recovery Furnace $CH_{4(Natural\ Gas)}$ (metric tons) = ($1x10^{-03}$) x (annual volume of natural gas fired in Chemical Recovery Furnace) x (annual HHV per Eq. C-2b) x (Table C-2 Emission Factor) Chemical Recovery Furnace $N_2O_{(Natural\ Gas)}$ (metric tons) = ($1x10^{-03}$) x (annual volume of natural gas fired in Chemical Recovery Furnace) x (annual HHV per Eq. C-2b) x (Table C-2 Emission Factor)

Table 3-12
Subpart TT Landfill Calculations
Verso Escanaba LLC - Escanaba, MI

Table 3-12 continued
Subpart TT Landfill Calculations
Verso Escanaba LLC - Escanaba, MI

Table 3-12
Subpart TT Landfill Calculations
Verso Escanaba LLC - Escanaba, MI

Characteristic	Landfill Unit						
	Unlined Area	Phase 1	Phase 2	Phases 3-4	Phase 5	Phase 6	Phases 7-11
Status of Landfill during reporting year:	Closed	Closed	Closed	Open	Open	Open	Unconstructed
Number of Waste streams:	8	8	8	8	8	8	8
Landfill capacity (cubic yards):	1.7 to 2.0 million	346,650	400,000	921,000	902,200	815,800	3,532,900
Use of Leachate recirculation and frequency of use over the past 10 years:	No	No	No	No	No	No	No
Year in which Landfill first accepted waste:	Early 1900's	2002	1992	1992	2000	2012	Unconstructed
Estimated year of Landfill closure:	2002 (stopped accepting waste in 1992)	2012 (post-closure care through 2042)	1995 (post-closure care through 2025)	2013	2014-2020	2022-2030	2055-2075

GHG Calculation Approach

Waste Stream Material (Mass in metric tons, as received, wet weight) - Rule Categories	Waste Stream Material (Mass in metric tons, as received, wet weight) - Description	Recommended Waste Quantity Estimation Method, Frequency, and Range of Years	Recordkeeping Details	Degradable organic carbon DOC_X [(a)]	Decay Rate (k) [(a)(b)]	Part 98 Calibration Requirements	CH_4 Calculation Equation
Pulp and Paper (other than industrial sludge)	Boiler ash, pulp, paper, wood waste, and lime waste	2001 to present Direct mass measurement - internal truck dumping tracking system. 1992 to 2000 Historic data and equations TT-2 or TT-3, utilizing Waste Disposal Factor (WDF). Open to 1991 Equation TT-4a, utilizing Landfill Capacity (LFC).	Record the annual quantities of waste disposed of in the landfills separately for each waste stream.	0.20	0.03	Document in corporate records.	TT-1 and TT-6
Industrial Sludge	Wastewater treatment plant residuals			0.09	0.04		TT-1 and TT-6
Construction and Demolition Waste	Waste from Construction and Demolition			0.08	0.03		TT-1 and TT-6
Other Industrial Solid Waste	General mill trash/garbage and asbestos waste			0.20	0.04		TT-1 and TT-6

(a) Factors obtained from Table TT-1 to 40 CFR Part 98, Subpart TT.

(b) Decay Rate factor (k) applicable climate classification selected for moderate climate with annual precipitation of 20-40 inches per year. The Mill does not utilize leachate recirculation. Climate data obtained from the Northeast Regional Climate Center at www.nrcc.cornell.edu. The normal precipitation is the arithmetic mean for each month over the 30 year period, adjusted as necessary, and includes the liquid water equivalent of snowfall.

GHG Sample Calculations

Equation	Sample Calculation
TT-1 Modeled CH_4 Generation	$G_{CH4} = [\sum_{x=S}^{T-1} \{W_X \times DOC_X \times MCF \times DOC_F \times F_X \times 16/12 \times (e^{-k(T-X-1)} - e^{-k(T-X)})\}]$ Where: X = Year in which waste was disposed. S = Start year of calculation, use 1960 or actual opening year of landfill, whichever is more recent. T = Reporting year for which emission are calculated. W_X = Quantity of waste disposed in the landfill in year X from measurement data and/or other company records, in metric tons, as received, wet weight. DOC_X = Degradable organic carbon for year X from 40 CFR Part 98, Subpart TT, Table TT-1 or from measurement data if available. MCF = Methane Correction Factor, use default value = 1.0. DOC_F = Fraction of DOCx, use default value = 0.5. F_X = Fraction of CH4 in landfill gas, use default value = 0.5. k = decay rate, from 40 CFR Part 98, Subpart TT, Table TT-1.
TT-2 Waste Disposal Factor (WDF)	WDF = $\left[\sum_{x=Y_1}^{Y_2} \left\{\frac{W_x}{N \times P_x}\right\}\right]$
TT-3 Calculate Historic Waste Disposal Quantity (W_X)	W_X = WDF x P_X
TT-4a Calculate Historic Waste Disposal Quantity (W_X)	$W_X = \frac{LFC}{(YrData - YrOpen + 1)}$
TT-6 CH_4 Generation	MG = G_{CH4} x (1-OX) Where: MG = Methane generation, adjusted for oxidation, from the landfill, for the reporting year. G_{CH4} = Modeled methane generated rate calculated from Eq. TT-1. OX = Oxidation fraction, use default value 0.1 (10%).

Table 3-13
Exempt Equipment Criteria
Verso Escanaba LLC - Escanaba, MI

Table 3-13
Exempt Equipment Criteria
Verso Escanaba LLC - Escanaba, MI

Exempt Equipment Type	Criteria	Exempt Emission Units
Portable Equipment	Designated and capable of being carried or moved from one location to another. Indications of portability include but are not limited to wheels, skids, carrying handles, dolly, trailer, or platform. Equipment is not portable if any one of the following conditions exists: (1) The equipment is attached to a foundation. (2) The equipment or a replacement resides at the same location for more than 12 consecutive months. (3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least two years, and operates at that facility for at least three months each year. (4) The equipment is moved from one location to another in an attempt to circumvent the portable residence time requirements of this definition.	The Escanaba Mill owns some equipment that meets this definition. Because this equipment is exempt no master list is maintained.
Emergency Generators	A stationary combustion device, such as a reciprocating internal combustion engine or turbine that serves solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued during power outages or natural disasters that are beyond the control of the owner or operator of the facility. An emergency generator operates only during emergency situations, for training of personnel under simulated emergency conditions, as part of emergency demand response procedures, or for standard performance testing procedures as required by law or by the generator manufacturer. A generator that serves as a back-up power source under conditions of load shedding, peak shaving, power interruptions pursuant to an interruptible power service agreement, or scheduled facility maintenance shall not be considered an emergency generator.	The Escanaba Mill owns some emergency generators. Because this equipment is exempt no master list is maintained.
Emergency Equipment	Any auxiliary fossil fuel-powered equipment, such as a fire pump, that is used only in emergency situations.	The Escanaba Mill owns some equipment that meets this definition. Because this equipment is exempt no master list is maintained.

4. QUALITY ASSURANCE AND QUALITY CONTROL (QA/QC)

This section of the GHG Monitoring Plan describes the specific QA/QC procedures that are part of the Escanaba Mill's effort to measure, record, and report GHG emissions. Where applicable, the Mill references existing QA/QC procedures and documents that have been developed for other regulatory programs at the Mill.

4.1 QA/QC OF GHG MEASUREMENT PROCESSES

The Mill is applying approved QA/QC procedures to all steps in the GHG measurement process to ensure the quality-assured measurement of the amount of fuels or process-related materials (e.g., black liquor solids) used and quality-assured determinations of the GHG properties of the fuels or process-related materials.

In most cases, the QA/QC practices will cover the quality of the measurement of the amount of fuels or process-related materials (e.g., black liquor solids) used and then a determination of the GHG properties of the fuels or process-related materials. In both instances, the use of U.S. EPA-approved testing procedures, sampling, and analytical practices will be used. Testing methods are sourced from the American Society of Testing and Materials (ASTM), the American National Standards Institute (ANSI), the National Council for Air and Stream Improvement (NCASI), the National Institute of Standards and Technology (NIST), and the Technical Association of the Pulp and Paper Industry (TAPPI). A summary of U.S. EPA's recommended procedures that will be part of the Mill's GHG measurement process is presented in Tables 4-1 through 4-6, along with the parameters for which the procedures apply.

Table 4-1
QA/QC Procedures for GHG Measurements for No. 7 Boiler
Verso Escanaba LLC - Escanaba, MI

Table 4-1
QA/QC Procedures for GHG Measurements for No. 7 Boiler
Verso Escanaba LLC - Escanaba, MI

Tier	Fuel	Parameter	Minimum Frequency per 40 CFR Part 98	Sampling Location	Initial Calibration	Accepted Methods
Tier 2 - Applicable for natural gas firing since the Mill routinely receives HHV data from local natural gas distribution company	Natural Gas	Fuel Usage	Annual	For GHG calculations No.7 Boiler natural gas usage is calculated under GP 001. No. 7 Boiler does have a flow meter, but for accounting purposes natural gas usage in No. 7 Boiler is determined based on steam production.	N/A	The flow meter and steam production instrumentation are maintained and calibrated as needed. There are no specific calibration requirements for natural gas usage in No. 7 Boiler as it falls under company records. No.7 Boiler natural gas usage is calculated under GP 001. Reference Table 5-1.
		HHV	Semi-Annual [(a)]	HHV values will be provided by the supplier on a monthly basis. The supplier collects samples representative of what is supplied to the Mill. Analytical results are maintained by the supplier and are available upon request.	N/A	Chromatographic analysis together with standard heating values of the fuel constituents, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions; or
						ASTM D1826-94 (Reapproved 2003) Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter (incorporated by reference, see §98.7); or
						ASTM D3588-98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels (incorporated by reference, see §98.7); or
						ASTM D4891-89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (incorporated by reference, see §98.7); or
						GPA Standard 2172-09 Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer (incorporated by reference, see §98.7)
Tier 3 - Applicable because the Mill routinely performs fuel sampling and analysis for HHV for the Tier 3 calculations required for the No. 8 boiler	Residual Oil	Fuel Usage	Monthly[(a)]	No. 7 Boiler does not currently burn residual fuel oil. If residual fuel oil is burned in the future the QA/QC requirements of 40 CFR 98 will be followed.	N/A	There are no calibration requirements for this meter at this time as the Mill does not currently burn residual fuel oil in No. 7 Boiler. If residual fuel oil is burned in the future the QA/QC requirements of 40 CFR 98 will be followed. Reference Table 5-1.
		HHV	Per Fuel Lot	No. 7 Boiler does not currently burn residual fuel oil. If residual fuel oil is burned in the future Tier 3 testing would be required as this is required on No. 8 Boiler.	N/A	ASTM-D4809-6 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method) (incorporated by reference, see §98.7)
						ASTM-D240-02 (Reapproved 2007) Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (incorporated by reference, see §98.7)
		Carbon Content	Monthly [(b)]	No. 7 Boiler does not currently burn residual fuel oil. If residual fuel oil is burned in the future Tier 3 testing would be required as this is required on No. 8 Boiler.	N/A	ASTM-D3238-95 (Reapproved 2005) Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method (incorporated by reference, see §98.7)
						ASTM-D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, see §98.7)

[(a)] If HHV for a specific fuel type is collected at a monthly (or greater) frequency, the Mill must collect monthly fuel usage readings.
[(b)] Residual fuel oil samples are collected monthly, not per fuel lot. See Table 5-1 for the explanation.

Table 4-2
QA/QC Procedures for GHG Measurements for No. 8 Boiler
Verso Escanaba LLC - Escanaba, MI

Table 4-2
QA/QC Procedures for GHG Measurements for No. 8 Boiler
Verso Escanaba LLC - Escanaba, MI

Tier	Fuel	Parameter	Minimum Frequency per 40 CFR Part 98	Sampling Location	Initial Calibration	Accepted Methods
Tier 2 - Applicable since the emission unit is greater than 250 MMBtu/hr and fires pipeline quality natural gas	Natural Gas	Fuel Usage	Annual	Direct measurement by a flow meter (13-F0103.4). See the Inspection and Maintenance Plan for details at L:\Local Initiatives\Environmental\ENVIRO\ Air\Title V\Recordkeeping\Inspection & Maintenance Plan\I&M Plan.xls	12/29/2009	This flow meter is calibrated annually per manufacturer's recommendations. Although this meter is calibrated annually, the QA/QC requirements of 40 CFR 98 do not require this as this meter falls under the company records provisions. Reference Table 5-1.
		HHV	Semi-Annual	HHV values will be provided by the supplier on a monthly basis. The supplier collects samples representative of what is supplied to the Mill. Analytical results are maintained by the supplier and are available upon request.	N/A	Chromatographic analysis together with standard heating values of the fuel constituents, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions; or
						ASTM D1826-94 (Reapproved 2003) Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter (incorporated by reference, see §98.7); or
						ASTM D3588-98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels (incorporated by reference, see §98.7); or
						ASTM D4891-89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (incorporated by reference, see §98.7); or
						GPA Standard 2172-09 Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer (incorporated by reference, see §98.7)
Tier 3 - Applicable because the Mill routinely performs fuel sampling and analysis for HHV for the Tier 3 calculations required for the emission unit	Residual Oil	Fuel Usage	Monthly[a]	Direct measurement by a flow meter (13-F0105.Q). See the Inspection and Maintenance Plan for details at L:\Local Initiatives\Environmental\ENVIRO\ Air\Title V\Recordkeeping\Inspection & Maintenance Plan\I&M Plan.xls	12/16/2009	This flow meter is calibrated annually per manufacturer's recommendations. Because this residual fuel oil meter falls under Tier 3, regular calibration is required. The E&I Techs follow the manufacturer's recommended procedures for calibration. Reference Table 5-1.
		HHV	Per Fuel Lot	HHV values are provided by the fuel suppliers.	N/A	ASTM-D4809-6 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method) (incorporated by reference, see §98.7)
						ASTM-D240-02 (Reapproved 2007) Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (incorporated by reference, see §98.7)
		Carbon Content	Monthly [b]	Carbon content samples are collected by the Mill and sent to an outside lab on a monthly basis for analysis. See the sampling SOP for more details at L:\Local Initiatives\Environmental\ ENVIRO\ Air\GHG\GHG Monitoring Plan\GHG Fuel Sampling SOP.pdf	N/A	ASTM-D3238-95 (Reapproved 2005) Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method (incorporated by reference, see §98.7)
						ASTM-D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, see §98.7)

[a] If HHV for a specific fuel type is collected at a monthly (or greater) frequency, the Mill must collect monthly fuel usage readings.

[b] Residual fuel oil samples are collected monthly, not per fuel lot. See Table 5-1 for the explanation.

Table 4-3
QA/QC Procedures for GHG Measurements for No. 9 Boiler
Verso Escanaba LLC - Escanaba, MI

Table 4-3
QA/QC Procedures for GHG Measurements for No. 9 Boiler
Verso Escanaba LLC - Escanaba, MI

Tier	Fuel	Parameter	Minimum Frequency per 40 CFR Part 98	Sampling Location	Initial Calibration	Accepted Methods
Tier 2 - Applicable due to the frequency of fuel sampling and analysis for HHV	Bark/Woodwaste	Fuel Usage	N/A	Bark and woodwaste are measured by the inventory method. The usage determined by the inventory method is allocated to No. 9 and No. 11 Boiler based on their PI Tag (70-F0402.BT) scaled usage by accounting.	N/A	Bark and woodwaste usage falls under the company records provisions. Usage information is important, therefore, the mill maintains the equipment as necessary, however, there are no specific calibration requirements for this equipment. Reference Table 5-1.
		HHV	Sampled weekly, samples composited and sent out monthly	The Fuel Sampler collects a representative sample weekly. The weekly samples are composited into one monthly sample and sent to a certified lab for analysis. See the sampling SOP for more details at L:\Local Initiatives\Environmental\ ENVIRO\Air\GHG\GHG Monitoring Plan\GHG Fuel Sampling SOP.pdf	N/A	ASTM D5865-07a Standard Test Methods for Gross Calorific Value of Coal and Coke (incorporated by reference, see §98.7).
Tier 2 - Applicable since the emission unit is greater than 250 MMBtu/hr and fires pipeline quality natural gas	Natural Gas	Fuel Usage	Monthly [a]	Direct measurement by a flow meter (03-F0108.4). See the Inspection and Maintenance Plan for details at L:\Local Initiatives\Environmental\ ENVIRO\Air\Title V\Recordkeeping\Inspection & Maintenance Plan\I&M Plan.xls	12/17/2009	This flow meter is calibrated annually per manufacturer's recommendations. Although this meter is calibrated annually, the QA/QC requirements of 40 CFR 98 do not require this as this meter falls under the company records provisions. Reference Table 5-1.
		HHV	Semi-Annual	HHV values will be provided by the supplier on a monthly basis. The supplier collects samples representative of what is supplied to the Mill. Analytical results are maintained by the supplier and are available upon request.	-	Chromatographic analysis together with standard heating values of the fuel constituents, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions ASTM D1826-94 (Reapproved 2003) Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter (incorporated by reference, see §98.7) ASTM D3588-98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels (incorporated by reference, see §98.7) ASTM D4891-89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (incorporated by reference, see §98.7) GPA Standard 2172-09 Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer (incorporated by reference, see §98.7)

[a] If HHV for a specific fuel type is collected at a monthly (or greater) frequency, the Mill must collect monthly fuel usage readings.

Table 4-4
QA/QC Procedures for GHG Measurements for No. 11 Boiler
Verso Escanaba LLC - Escanaba, MI

Table 4-4
QA/QC Procedures for GHG Measurements for No. 11 Boiler
Verso Escanaba LLC - Escanaba, MI

Tier	Fuel	Parameter	Minimum Frequency per 40 CFR Part 98	Sampling Location	Initial Calibration	Accepted Methods
Tier 1	Pellet Fuel	Mass	N/A	Pellet Fuel is measured by the inventory method. This is then compared to the PI tag (70-PELBUCK.LQ). The PI tag data is calculated using the average weight per bucket multiplied by the number of buckets used.	N/A	Pellet fuel usage falls under the company records provisions. Usage information is important; therefore, the mill maintains the equipment as necessary. However, there are no specific calibration requirements for this equipment. Reference Table 5-1.
Tier 2 - Applicable since the emission unit is greater than 250 MMBtu/hr, fires pipeline quality natural gas, and the frequency of fuel sampling and analysis for HHV	Natural Gas Used for calculation of CH_4 and N_2O emissions.	Fuel Usage	Annual	Direct measurement by a flow meter (68-F2404.4). See the Inspection and Maintenance Plan for details at L:\Local Initiatives\Environmental\ ENVIRO\Air\Title V\Recordkeeping\Inspection & Maintenance Plan\I&M Plan.xls	12/18/2009	This flow meter is calibrated annually per manufacturer's recommendations. Although this meter is calibrated annually, the QA/QC requirements of 40 CFR 98 do not require this as this meter falls under the company records provisions. Reference Table 5-1.
		HHV	Semi-Annual	HHV values will be provided by the supplier on a monthly basis. The supplier collects samples representative of what is supplied to the Mill. Analytical results are maintained by the supplier and are available upon request.	N/A	Chromatographic analysis together with standard heating values of the fuel constituents, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions
						ASTM D1826-94 (Reapproved 2003) Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter (incorporated by reference, see §98.7)
						ASTM D3588-98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels (incorporated by reference, see §98.7)
						ASTM D4891-89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (incorporated by reference, see §98.7)
						GPA Standard 2172-09 Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer (incorporated by reference, see §98.7)
	Bark/Wood Waste & WWTP Sludge Used for calculation of CH_4, N_2O and Biogenic CO_2 emissions.	Fuel Usage	N/A	Bark and Woodwaste are measured by the inventory method. The usage determined by the inventory method is allocated to No. 9 and No. 11 Boiler based on scaled usage by accounting PI Tag 70-F0402.BT. WWTP Sludge is measured by truckload counts that are sent to No. 11 Boiler to burn (11-LQ1004). See Table 5-1 for more details.	N/A	Bark, woodwaste, and sludge usage fall under the company records provisions. Usage information is important, therefore, the mill maintains the equipment as necessary, however, there are no specific calibration requirements for this equipment. Reference Table 5-1.
		HHV	Weekly Sampling for Analysis of Monthly Composite	The Fuel Sampler collects a representative sample weekly. The weekly samples are composited into one monthly sample and sent to a certified lab for analysis. See the sampling SOP for more details at L:\Local Initiatives\Environmental\ENVIRO \Air\GHG\GHG Monitoring Plan\GHG Fuel Sampling SOP.pdf	N/A	ASTM D5865-07a Standard Test Methods for Gross Calorific Value of Coal and Coke (incorporated by reference, see §98.7).

Table 4-4 cont'd

Table 4-4
QA/QC Procedures for GHG Measurements for No. 11 Boiler
Verso Escanaba LLC - Escanaba, MI

Tier	Fuel	Parameter	Minimum Frequency per 40 CFR Part 98	Sampling Location	Initial Calibration	Accepted Methods
Tier 3 - Applicable because the Mill routinely performs fuel sampling and analysis for HHV for the Tier 3 calculations required for the emission unit	Bituminous Coal Used for calculation of CH_4 and N_2O emissions.	Mass	N/A	Coal is measured by the inventory method. This is then compared to the PI tag 68-F0112.4, which is based on scaled weight.	N/A	Coal usage falls under the company records provisions. Usage information is important, therefore, the mill maintains the equipment as necessary, however, there are no specific calibration requirements for this equipment. Reference Table 5-1.
		HHV	Per fuel lot	This sampling and testing is done by the suppliers. The results are sent to Purchasing and Environmental and kept in File 8.15.6.	N/A	ASTM D5865-07a Standard Test Methods for Gross Calorific Value of Coal and Coke (incorporated by reference, see §98.7).
	TDF Used for calculation of CH_4 and N_2O emissions.	Mass	N/A	TDF is measured by the inventory method. This is then compared to the PI tag (70-TDFBUCK.LQ). The PI tag data is calculated using the average weight per bucket multiplied by the number of buckets used.	N/A	TDF usage falls under the company records provisions. Usage information is important, therefore, the mill maintains the equipment as necessary, however, there are no specific calibration requirements for this equipment. Reference Table 5-1.
		HHV	Weekly Sampling for Analysis of Monthly Composite	The Fuel Sampler collects a representative sample weekly. The weekly samples are composited into one monthly sample and sent to a certified lab for analysis. See the sampling SOP for more details at L:\Local Initiatives\Environmental\ENVIRO\ Air\GHG\GHG Monitoring Plan\GHG Fuel Sampling SOP.pdf	N/A	ASTM D5865-07a Standard Test Methods for Gross Calorific Value of Coal and Coke (incorporated by reference, see §98.7).

[a] Initial calibration not required by January 1, 2010 if previously calibrated in accordance with Part 98 and the time interval between successive calibrations as required by Part 98 has not elapsed. If equipment is not certified prior to initial deadline, Tier 2 or 3 may be used to report GHG in 2010.

Table 4-5
QA/QC Procedures for GHG Measurements for Lime Kiln & Recovery Boiler
Verso Escanaba LLC - Escanaba, MI

Table 4-5
QA/QC Procedures for GHG Measurements for Lime Kiln & Recovery Boiler
Verso Escanaba LLC - Escanaba, MI

Tier	Fuel	Parameter	Minimum Frequency per 40 CFR Part 98	Sampling Location	Initial Calibration	Accepted Methods
Tier 2 - Per the requirements of §98.273(a)(1) & (2) and the frequency of fuel sampling and analysis for HHV.	Natural Gas	Fuel Usage	Annual	Direct measurement by a flow meter (13-F0103.4). See the Inspection and Maintenance Plan for details at L:\Local Initiatives\Environmental\ENVIRO\Air\Title V\Recordkeeping\Inspection & Maintenance Plan\I&M Plan.xls	12/29/2009	This flow meter is calibrated annually per manufacturer's recommendations. Although this meter is calibrated annually, the QA/QC requirements of 40 CFR 98 do not require this as this meter falls under the company records provisions. Reference Table 5-1.
		HHV	Semi-Annual	HHV values will be provided by the supplier on a monthly basis. The supplier collects samples representative of what is supplied to the Mill. Analytical results are maintained by the supplier and are available upon request.	N/A	Chromatographic analysis together with standard heating values of the fuel constituents, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions; or
						ASTM D1826-94 (Reapproved 2003) Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter (incorporated by reference, see §98.7); or
						ASTM D3588-98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels (incorporated by reference, see §98.7); or
						ASTM D4891-89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (incorporated by reference, see §98.7); or
						GPA Standard 2172-09 Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer (incorporated by reference, see §98.7)

Table 4-5 cont'd

Table 4-5
QA/QC Procedures for GHG Measurements for Lime Kiln & Recovery Boiler
Verso Escanaba LLC - Escanaba, MI

Tier	Fuel	Parameter	Minimum Frequency per 40 CFR Part 98	Sampling Location	Initial Calibration	Accepted Methods
Per the requirements of §98.273(a)(3).	BLS	Mass	N/A	**FLOW**: Direct measurement of BLS fired by 3 calibrated flow meters (15-0203, 15-0210A, & 15-0210B) at source and totalized in PI Tag (15-DTOT7). See the Inspection and Maintenance Plan for details at L:\Local Initiatives\Environmental\ ENVIRO\Air\Title V\Recordkeeping\Inspection & Maintenance Plan\I&M Plan.xls. **SOLIDS**: Black Liquor solids are measured continually by averaging 2 refractometers (15-D0204.4 & 15-D0706.4). These instruments are calibrated by comparing the results to the samples collected and analyzed by the Fuel Tester. The results are kept in File 8.15. In addition, samples are sent to an outside lab for analysis at least annually.	N/A	T-650 om-05 Solids Content of Black Liquor, TAPPI (incorporated by reference in §98.7). Flow meter is sent to the manufacturer for calibration on an as needed basis. This is less often than annually. Records of Measurement made with an online measurement system that determines the mass of spent liquor solids fired.
		HHV	Annual	A sample is collected at least annually and sent to a lab to run a certified test.	N/A	T684 om-06 Gross Heating Value of Black Liquor, TAPPI (incorporated by reference, see §98.7). ASTM D5865-07a Standard Test Methods for Gross Calorific Value of Coal and Coke (incorporated by reference, see §98.7).
Tier 3 - Per the requirements of §98.273(a)(1) & (2) because a quality assured flow meter is used to measure the amount of residual fuel oil fired in the emission unit.	Residual Oil	Fuel Usage	Monthly[a]	Direct measurement by a flow meter (13-F0105.Q). See the Inspection and Maintenance Plan for details at L:\Local Initiatives\Environmental\ENVIRO\ Air\Title V\Recordkeeping\Inspection & Maintenance Plan\I&M Plan.xls	12/16/2009	This flow meter is calibrated annually per manufacturer's recommendations. Because this residual fuel oil meter falls under Tier 3, regular calibration is required. The E&I Techs follow the manufacturer's recommended procedures for calibration. Reference Table 5-1.
		HHV	Per Fuel Lot	HHV values are provided by the fuel suppliers.	N/A	ASTM-D4809-6 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method) (incorporated by reference, see §98.7) ASTM-D240-02 (Reapproved 2007) Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (incorporated by reference, see §98.7)
		Carbon Content	Sampled weekly, samples composited and sent out monthly [b]	Carbon content samples are collected by the Mill weekly and sent to an outside lab on a monthly basis for analysis. See the sampling SOP for more details at L:\Local Initiatives\Environmental\ ENVIRO\ Air\GHG\GHG Monitoring Plan\GHG Fuel Sampling SOP.pdf	N/A	ASTM-D3238-95 (Reapproved 2005) Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method (incorporated by reference, see §98.7) ASTM-D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, see §98.7)

[a] If HHV for a specific fuel type is collected at a monthly (or greater) frequency, the Mill must collect monthly fuel usage readings.

Table 4-6
QA/QC Procedures for GHG Measurements of CO_2 Exhausted to PCC Plant
Verso Escanaba LLC - Escanaba, MI

Table 4-6
QA/QC Procedures for GHG Measurements of CO_2 Exhausted to PCC Plant
Verso Escanaba LLC - Escanaba, MI

Parameter	Minimum Frequency per 40 CFR Part 98	Sampling Location	Initial Calibration Deadline	Accepted Methods
Exhaust Flow to PCC Plant	Quarterly	Direct measurement of flow rate in duct downstream of Lime Kiln by pitot flow sensor.	N/A	Applicable method published by a consensus-based standards organization or industry standard practices if no appropriate standard method developed by a consensus-based standards organization exists. The exhaust flow to the PCC plant is recorded by plant personnel on a quarterly basis.
CO_2 Concentration (% by volume) in Exhaust to PCC Plant	Quarterly	Direct measurement in duct downstream of Lime Kiln by extraction sample and gas temperature measurement.	N/A	Applicable method published by a consensus-based standards organization or industry standard method. The Mill utilizes U.S. EPA Method 3.
CO_2 Density in Exhaust to PCC Plant	Quarterly	Direct measurement in duct downstream of Lime Kiln by extraction sample and gas temperature measurement.	N/A	Applicable method published by a consensus-based standards organization or industry standard practices. Per 40 CFR Part 98.424(c), if you apply the density value for CO_2 at standard conditions, you must use 0.001868 metric tons per standard cubic meter.

4.2 QA/QC OF GHG REPORTING PRACTICES

The Escanaba Mill uses a GHG Calculation Spreadsheet Tool, designed according to the specifications of this Monitoring Plan, to determine the mass of GHG emitted each year. The Spreadsheet Tool underwent initial third-party QA to make certain that the calculations are being performed properly. Standard Mill QA procedures for data entry in the Spreadsheet Tool are used, as discussed in the Mill's quality control manual(s).

4.3 TRAINING

The Escanaba Mill will collect samples, report, record, and calculate GHG emissions in compliance with the requirements contained in 40 CFR Part 98. The designated representative at the Escanaba Mill is responsible for ensuring that all personnel involved in these activities are properly trained. This GHG Monitoring Plan is the primary source of information regarding reporting requirements and will be used as the basis for training personnel.

5. PROCESS OF DATA REPORTING AND ARCHIVING

This section of the GHG Monitoring Plan describes the general procedures for reporting GHG emissions to U.S. EPA, including descriptions of the company records and personnel utilized for collecting data and the process of archiving reported data and supporting information. In addition, the procedures for updating this GHG Monitoring Plan due to changes in either Mill operations or the requirements of 40 CFR Part 98 are also outlined in Section 5.

5.1 COMPANY RECORDS

The Escanaba Mill will utilize "company records" for a significant portion of the GHG reporting process. In context of the GHG emission calculation process and fuel flow information, company records encompass the amount of fuel consumed by a stationary combustion unit (or by a group of such units), how the amount of fuel was determined, and any calculations performed to quantify fuel usage. Company records may include, but are not limited to, direct measurements of fuel consumption by gravimetric or volumetric means, tank drop measurements, and calculated values of fuel usage obtained by measuring auxiliary parameters such as steam generation or unit operating hours. Fuel billing records obtained from fuel suppliers qualify as company records. A summary of the methods used to measure and record fuel use is provided in Table 5-1.

5.2 COMPANY RESOURCES

The reporting of GHG will require the coordination of several operational areas at the Escanaba Mill. Accounting, recovery and boiler operations, maintenance, and the environmental departments will all have responsibilities related to data collection, data calculation, data management, QA/QC requirements, and data reporting. A summary of the positions responsible for activities related to the reporting of GHG is provided in Table 5-2.

5.3 DATA REPORTING PROCESS

The Escanaba Mill electronically submits annual GHG Summary Reports to U.S. EPA via the Electronic Greenhouse Gas Reporting Tool (e-GGRT) no later than March 31st of each calendar year, or any other reporting date promulgated by U.S. EPA, for GHG emissions associated with each previous calendar year. The information that is to be included in each annual GHG Summary Report is specified at 40 CFR §98.3(c), §98.36, §98.276 and §98.466 for Subparts A, C, AA, PP, and TT, respectively. The Mill's calculation spreadsheets include the necessary and appropriate emission calculations necessary to update U.S. EPA's e-GGRT database and generate each annual report.

The operators/owners of the Escanaba Mill have assigned the designated representative identified in Table 5-2. An alternate designated representative may act on behalf of the designated representative if so directed by the Manager of the Mill. Either the appointed designated representative or the appointed alternate designated representative is responsible for electronically certifying each annual GHG Summary Report that is prepared in e-GGRT in accordance with 40 CFR Part 98 requirements. The designated representative or alternate designated representative must examine all GHG calculations and supporting information prior to electronically certifying and submitting each GHG submittal. The actual submittal of each annual GHG Summary Report may also be performed by a third-party "agent" that is delegated by either the designated representative or alternate designated representative, provided that the delegated party is identified to U.S. EPA in an electronic notification. Once the information regarding the agent is received by U.S. EPA, the delegated agent remains delegated until such notice is provided removing the existing delegated agent. The Escanaba Mill recognizes that when an agent submits a report, they are not agreeing to the Certification Statement, but rather submitting the Certification Statement on behalf of the designated representative or alternate designated representative who is agreeing to the Certification Statement. An agent is only authorized to make the electronic submission on behalf of the designated representative, not to sign (i.e., agree to) the certification statement.

5.4 CORRECTING REPORTED DATA

The annual GHG inventory reports will be corrected if errors are discovered. The Escanaba Mill will submit a revised GHG report to U.S. EPA within 45 days of the identification of a reporting error. As part of the correction process, the Escanaba Mill will identify the original error and provide the corrected data.

5.5 DATA ARCHIVING

Records related to the GHG inventory program will be maintained for a minimum of three (3) years. The format of all records may be electronic or hard copy and must be made available to U.S. EPA for review upon request. A copy of the information that is required to be archived is contained in Table 5-4.

5.6 GHG MONITORING PLAN UPDATING

U.S. EPA requires that the GHG Monitoring Plan be updated to reflect changes to the Mill, to the approach used to calculate annual GHG, or to reflect changes in the requirements of Part 98. The Escanaba Mill will review the GHG Monitoring Plan periodically. As part of the review, the following items will be considered:

- Applicability of new source categories.
- Changes to monitoring instrumentation/methods
- Improvements in monitoring techniques to reduce missing data or instrument downtime.
- Changes to QA/QC procedures.

The Escanaba Mill will document and record any revisions to the GHG Monitoring Plan in Table 5-5.

Table 5-1
Fuel Use Measurement Recordkeeping Methods
Verso Escanaba LLC - Escanaba, MI

Table 5-1
Fuel Use Measurement Recordkeeping Methods
Verso Escanaba LLC - Escanaba, MI

Fuel	Method of Measurement
Natural Gas	Natural gas sent to the mill is measured and invoiced through the DTE metering system. Once it enters into the mill, it is sent to the various users. The Mill meters the largest users of natural gas in the mill. They are: The Nos. 7, 8, 9, & 11 boilers, the Recovery Furnace, the Thermal Oxidizer, the Lime Kiln, and the Nos. 1 and 3 coaters. The rest of the natural gas is not metered inside the mill. The difference from what the above users consume and what we are invoiced for is allocated to other users throughout the mill using an analysis of the various heating loads from an internal audit made in the mill.
No. 6 Fuel Oil	Fuel oil consumed in the mill is measured by the inventory method (Beginning inventory in the tank plus receipts minus the ending inventory is used to determine usage). This is compared to the flow (PI tag data) of the three users – No. 8 Boiler, Recovery Furnace and the Lime Kiln. If there is a vast difference between the numbers, an investigation is completed to rectify the discrepancy. No. 8 Boiler is the only source required to have carbon testing done on fuel oil. The suppliers agreed to provide HHV(BTU) analyses with every fuel lot but not carbon content. Because fuel oil is not routinely used in No. 8 Boiler and because the tank holds one million gallons, samples will be analyzed monthly instead of per fuel lot. This sampling method will provide representative results of the carbon content in fuel oil.
Coal	Coal consumed in the mill is measured by the inventory method (Beginning inventory plus receipts minus ending inventory). This is compared to the measured data (PI tag) based on the scaled weight. The only user of coal is No. 11 boiler.
Bark/Wood Residue	Bark consumed in the mill is measured by the inventory method. Two boilers burn bark - No. 9 and No. 11. The usage determined by the inventory method is allocated to the boilers based on their PI tag scaled usage.
TDF	TDF consumed in the mill is measured by the inventory method. This is compared to the measured (PI tag) data. The PI tag data is calculated using the average weight per bucket multiplied by the number of buckets mixed with the bark, Pellet Fuel, and sludge each shift. No. 11 is the only boiler that burns TDF.
Sludge	Sludge is measured by truck counts. The number of truckloads is multiplied by the average weight per truckload. This fuel is not charged internally. Sludge, bark, Pellet Fuel, and TDF are all mixed together at specific ratios before being fed into No. 11 boiler. No. 11 is the only boiler that burns sludge.
Pellet Fuel	Pellet Fuel consumed in the mill is measured by the inventory method. This is compared to the measured (PI tag) data. The PI tag data is calculated using the average weight per bucket multiplied by the number of buckets mixed with the bark, TDF, and sludge each shift. No. 11 is the only boiler that burns Pellet Fuel.
No. 2 Diesel Fuel Oil	No. 2 diesel was burned in the Recovery Furnace in 2009 for a Black Liquor tax credit. It is not anticipated that No. 2 Diesel Fuel will be burned by any of the combustion processes in the future. A measurement system will be developed if No. 2 Fuel Oil is burned in the future.
Black Liquor	Black liquor flow and solids are measured with on-line instrumentation in the Boiler House. The fuel is not charged off in SAP. See Table 4-5 for more details.

Table 5-2
Positions Involved with GHG Reporting
Verso Escanaba LLC - Escanaba, MI

Table 5-2
Positions Involved with GHG Reporting
Verso Escanaba LLC - Escanaba, MI

Task	Personnel	Frequency
Personnel Training	Environmental Engineer	As Needed
Direct Fuel Measurement Device Calibration	E&I Maintenance Supervisor-Kraft Mill and E&I Maintenance Supervisor-Boiler House	Refer to Tables 4-1 through 4-5 and the I&M Plan in Appendix C
Non-Direct Measurement Data Collection	Senior Financial Analyst & Environmental Engineer	Annual
Fuel Sampling	Technical Services Fuel Sampler	Refer to Tables 4-1 through 4-5 and the SOP Manual in Appendix B
GHG Emissions Calculations	Environmental Engineer and Corporate Energy Database Manager	Annual
GHG Emissions Annual Report	Designated Representative - Refer to Table 5-3	Annual

Table 5-3
Designated Representative and Alternate Designated Representative
Verso Escanaba LLC - Escanaba, MI

Table 5-3
Designated Representative and Alternate Designated Representative
Verso Escanaba LLC - Escanaba, MI

Contact Info	Designated Representative	Alternate Representative (if any)
Name	Adam Becker	
Title	Environmental Engineer	Environmental Manager
Address	7100 county Rd 426, Escanaba, MI 49829	7100 county Rd 426, Escanaba, MI 49829
E-Mail Address	adam.becker@versoco.com	
Telephone	906-233-2929	
Facsimile	906-233-2266	906-233-2266

Table 5-4
Archived GHG Information
Verso Escanaba LLC - Escanaba, MI

Table 5-4
Archived GHG Information
Verso Escanaba LLC - Escanaba, MI

All subject units
GHG Monitoring Plan
Affected operations (pulp and paper, combustion, WWTP, landfill, etc.)
Raw data by subject units (fuel types, raw materials)
GHG calculations and methodology
Analytical results
Mill operating data or process information by year and used in GHG calculations
Copies of GHG annual reports
Missing data computations (dates, reason for missing data, actions to minimize future missing data)
Results of certifications and QA test of CEMs and other instrumentation used to generate GHG annual reports
Results of calibration accuracy tests
Revisions of annual reports

Table 5-5
GHG Monitoring Plan Revisions Log
Verso Escanaba LLC - Escanaba, MI

Table 5-5
GHG Monitoring Plan Revisions Log
Verso Escanaba LLC - Escanaba, MI

Date	Authorized by	Revision Description ***Document Section/Page Number*** ***Regulatory Citation*** ***Brief Revision Description and Justification***
5/1/2012	Bill Racine	Updated Table C-1; Incorporated Subpart TT into Sections 3.6, 3.8.3, 3.9, and Table 2-2; Added Table 3-13 for Subpart TT calculations; Removed Appendix containing Draft notification correspondence; Removed Tables 3-15 through 3-20; Incorporated CEMs monitoring on No. 11 Boiler into Section 3.4.4; Updated Section 3.9 to account for reporting in e-GGRT; Updated Section 4.2 to reflect current practices; Adjusted Tier applicability in 3.5.1 for the Lime Kiln and Section 3.5.3 for Chemical Recovery Furnace; Revised Section 5.3; Added Table TT-1 to Appendix
6/12/2014	Paula LaFleur	Updated Tables C-1, C-2, AA-1, AA-2, TT-1 based on November 2013 revisions to the GHG reporting rule. Updated the GWPs. Revised the GHG emissions spreadsheet to accommodate the addition of pellet fuel firing in the No. 11 boiler. Revised the GHG emissions spreadsheet to accommodate the newly added regulatory waste stream classification "industrial sludge." Revised Subpart TT calculations to show the classifications of waste streams in accordance with 40 CFR Part 98. Incorporated 40 CFR Part 98 Subpart PP into the GHG emissions spreadsheet. Revised the lime kiln GHG requirements in accordance with the provisions applicable to the Mill under 40 CFR Part 98 Subpart PP.
5/3/2016	Paula LaFleur	Updated section 3.1 "Tier 4 required" language to match rule changes. Updated section 3.4.4, No. 11 Boiler Emissions Unit Information to reflect the use of Tier 2 and 3. Deleted Tier 4 language. Section 3.9.1, modifed missing carbon content language to include TDF and coal.
3/7/2019	Adam Becker	Updated company name due to change and Designated Representative.
3/24/2020	Adam Becker	Updated Table 3-7 to reflect the change from Tier 4 calculation to Tier 3 calculations for No. 11 Boiler.

APPENDIX A -
40 CFR PART 98 EMISSION FACTOR TABLES

Table C-1

40 CFR Part 98

Table C-1 of Subpart C

Default CO_2 Emission Factors and High Heat Value for Various Types of Fuel

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Coal and Coke	**MMBtu/short ton**	**kg CO_2/MMBtu**
Anthracite	25.09	103.69
Bituminous	24.93	93.28
Subbituminous	17.25	97.17
Lignite	14.21	97.72
Coal Coke	24.80	113.67
Mixed (Commercial Sector)	21.39	94.27
Mixed (Industrial Coking)	26.28	93.90
Mixed (Industrial Sector)	22.35	94.67
Mixed (Electric Power Sector)	19.73	95.52
Natural Gas	**MMBtu/scf**	**kg CO_2/MMBtu**
(Weighted U.S. Average)	1.026E-03	53.06
Petroleum Products	**MMBtu/gallon**	**kg CO_2/MMBtu**
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Distillate Fuel Oil No. 5	0.140	72.93
Distillate Fuel Oil No. 6	0.150	75.10
Used Oil	0.138	74.00
Kerosene	0.135	75.20
Liquefied Petroleum Gases (LPG)	0.092	61.71
Propane	0.091	62.87
Propylene	0.091	67.77
Ethane	0.068	59.60
Ethanol	0.084	68.44
Ethylene	0.058	65.96
Isobutane	0.099	64.94
Isobutylene	0.103	68.86
Butane	0.103	64.77
Butylene	0.105	68.72
Naphtha (<401 deg F)	0.125	68.02
Natural Gasoline	0.110	66.88
Other Oil (>401 deg F)	0.139	76.22
Pentanes Plus	0.110	70.02
Petrochemical Feedstocks	0.125	71.02
Petroleum Coke	0.143	102.41
Special Naphtha	0.125	72.34
Unfinished Oils	0.139	74.54
Heavy Gas Oils	0.148	74.92
Lubricants	0.144	74.27
Motor Gasoline	0.125	70.22
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22
Asphalt and Road Oil	0.158	75.36
Crude Oil	0.138	74.54
Other Fuels - Solid	**MMBtu/short ton**	**kg CO_2/MMBtu**
Municipal Solid Waste	9.95	90.7
Tires	28.00	85.97
Plastics	38.00	75.00
Petroleum Coke	30.00	102.41
Other Fuels - Gaseous	**MMBtu/scf**	**kg CO_2/MMBtu**
Blast Furnace Gas	9.200E-05	274.32
Coke Oven Gas	5.990E-04	46.85
Propane Gas	2.516E-03	61.46
Fuel Gas	1.388E-03	59.00
Biomass Fuels - Solid	**MMBtu/short ton**	**kg CO_2/MMBtu**
Wood and Wood Residuals (dry basis)	17.48	93.80
Agricultural Byproducts	8.25	118.17
Peat	8.00	111.84
Solid Byproducts	10.39	105.51
Biomass Fuels - Gaseous	**MMBtu/scf**	**kg CO_2/MMBtu**
Landfill Gas	4.85E-04	52.07
Other Biomass Gas	6.55E-04	52.07
Biomass Fuels - Liquid	**MMBtu/gallon**	**kg CO_2/MMBtu**
Ethanol	0.084	68.44
Biodiesel (100%)	0.128	73.84
Rendered Animal Fat	0.125	71.06
Vegetable Oil	0.120	81.55

Table C-2
40 CFR Part 98

Table C-2 of Subpart C
Default CH_4 and N_2O Emission Factors for Various Types of Fuel

Fuel Type	Default CH_4 Emission Factor (kg CH_4/MMBtu)	Default N_2O Emission Factor (kg N_2O/MMBtu)
Coal and Coke (All fuel types in Table C-1)	1.10E-02	1.60E-03
Natural Gas	1.00E-03	1.00E-04
Petroleum (All fuel types in Table C-1)	3.00E-03	6.00E-04
Fuel Gas	3.00E-03	6.00E-04
Municipal Solid Waste	3.20E-02	4.20E-03
Tires	3.20E-02	4.20E-03
Blast Furnace Gas	2.20E-05	1.00E-04
Coke Oven Gas	4.80E-04	1.00E-04
Biomass Fuels-Solid (All fuel types in Table C-1, except wood and wood residuals)	3.20E-02	4.20E-03
Wood and wood residuals	7.20E-03	3.60E-03
Biomass Fuels - Gaseous (All fuel types in Table C-1)	3.20E-03	6.30E-04
Biomass Fuels - Liquid (All fuel types in Table C-1)	1.10E-03	1.10E-04

Table AA-1
40 CFR Part 98

Table AA-1 of Subpart AA

Kraft Pulping Liquor Emissions Factors for Biomass-Based CO_2, CH_4, and N_2O

Wood Furnish	Biomass-Based Emissions Factors (kg/MMBtu HHV)		
	CO_2	CH_4	N_2O
North American Softwood	94.4	0.0019	0.00042
North American Hardwood	93.7	0.0019	0.00042
Bagasse	95.5	0.0019	0.00042
Bamboo	93.7	0.0019	0.00042
Straw	95.1	0.0019	0.00042

Table AA-2
40 CFR Part 98

Table AA-2 of Subpart AA

Kraft Lime Kiln and Calciner Emissions Factors for CH4 and N2O

Fuel	Fossil Fuel-Based Emissions Factors (kg/MMBtu HHV)			
	Kraft lime kilns		Kraft calciners	
	CH_4	N_2O	CH_4	N_2O
Residual Oil (any type)	0.0027	0.000	0.0027	0.0003
Distillate Oil (any type)	0.0027	0.000	0.0027	0.0004
Natural Gas	0.0027	0.000	0.0027	0.0001
Biogas	0.0027	0.000	0.0027	0.0001
Petroleum Coke	0.0027	0.000	N/A[(a)]	N/A[(a)]
Other Fuels	See Table C-2	0.000	See Table C-2	See Table C-2

(a) Emission factors for kraft calciners are not available.

Table TT-1
40 CFR Part 98

Table TT-1 of Subpart TT
Default DOC and Decay Rate Values for Industrial Waste Landfills

Industry/Waste Type	DOC (weight fraction, wet basis)	k [dry climate[a]] (yr^{-1})	k [moderate climate[a]] (yr^{-1})	k [wet climate[a]] (yr^{-1})
Food Processing (other than industrial sludge)	0.22	0.06	0.12	0.18
Pulp and Paper (other than industrial sludge)	0.20	0.02	0.03	0.04
Wood and Wood Product (other than industrial sludge)	0.43	0.02	0.03	0.04
Construction and Demolition	0.08	0.02	0.03	0.04
Industrial Sludge	0.09	0.02	0.04	0.06
Inert Waste [i.e., wastes listed in §98.460(c)(2)]	0.00	0.00	0.00	0.00
Other Industrial Solid Waste (not otherwise listed)	0.20	0.02	0.04	0.06

Notes:

(a) The applicable climate classification is determined based on the annual rainfall plus the recirculated leachate application rate. Recirculated leachate application rate (inches/year) is the total volume of leachate recirculated and applied to the landfill divided by the area of the portion of the landfill containing waste (with appropriate unit conversions).

(1) Dry climate = precipitation plus recirculated leachate less than 20 inches/year.

(2) Moderate climate = precipitation plus recirculated leachate from 20 to 40 inches/year (inclusive).

(3) Wet climate = precipitation plus recirculated leachate greater than 40 inches/year.

(b) The above table is comprised of DOC and k values from Table TT-1 to Subpart TT of Part 98 as Revised in November 2013.

APPENDIX B -
GHG FUEL SAMPLING PLAN

Sampling Procedures for Tire Derived Fuel (TDF), Sludge, Woodwaste, Pellet Fuel, No. 6 Fuel Oil, Black Liquor, & Coal

Revised March 8, 2017

Analyses:

TDF (Monthly) - Moisture, Ash, High Heating Value (HHV or BTU), Sulfur, and Wire Content, Carbon Content
TDF (Annual) - Metals, Mercury, Wire Content, & Moisture
Pellet Fuel - Moisture, Ash, High Heating Value (HHV or BTU), and Sulfur
Sludge - Moisture, Ash, and HHV (BTU)
Woodwaste – Moisture, Ash, and HHV (BTU)
Fuel Oil - Carbon Content (CHN)
Black Liquor - Moisture, Ash, & HHV (BTU)
Coal (Annual) - Moisture, Ash, HHV (BTU), & Sulfur
Note: See the example Chain of Custodies at L:\Local Initiatives\Environmental\ENVIRO\Air\GHG\Lab Analyses\Chain of Custodies

Sample ID's: TDF, Pellet Fuel, Sludge, Woodwaste No. 6 Fuel Oil, Black Liquor, & Coal

Sample Type: Grabs, composited into representative sample. See Collection Section.

Sample Frequency:

TDF, Sludge, Woodwaste & Pellet Fuel - Weekly samples composited into monthly composite.
Black Liquor – Quarterly Sample
No. 6 Fuel Oil – Monthly Sample
Coal - Annual Sample for ROP compliance (EU No. 11, VI.5 & 6)
TDF (Metals) - Annual Sample for ROP compliance (EU No. 11, VI.5 & 6)

Collection:

TDF, Sludge, Woodwaste & Pellet Fuel (Monthly) – These fuels are all stored on the Woodwaste and Coal Pad. There is a lot of heavy traffic in this area. Drive very carefully and notify the Woodwaste & Coal Area at 2464 when you will be sampling.

Note: Occasionally there is no sludge on the pad, in this case call the wastewater treatment plant operator at 2451 and get a sample from the waste treatment plant. If there is no pellet fuel on the pad, omit this sample.

1. Each week, select 5 representative sampling locations evenly spaced around each pile. **Please note that woodwaste includes woodwaste, bark, and fines. These materials are stored in several piles. To be sure you get some woodwaste, bark, and fines you can collect the already mixed woodwaste sample that the Hough drivers put into No. 11 Boiler. This is a representative sample.**
2. At each sampling site, dig into the pile at least 18", at about waist height.
3. Insert a clean shovel into the hole and withdraw a representative sample.

4. Place sludge samples into clean jars. Place TDF, Woodwaste and Pellet Fuel samples into clean plastic Ziploc bags. Seal all samples and mark the containers with contents and the date sampled.
5. At the end of the month, mix all the weekly samples in their separate containers then composite the weekly samples into one monthly sample. The TDF, Woodwaste and Pellet Fuel samples are to be placed into gallon-size Ziploc bags and double bagged. The sludge sample is to be placed into a clean glass jar provided by the lab.
6. Label samples either TDF, Sludge, Woodwaste or Pellet Fuel and fill out the appropriate Chain-of Custody. (See L:\Local Initiatives\Environmental\ ENVIRO\Air\ GHG\Lab Analyses\Chain of Custodies).

No. 6 Fuel Oil (Monthly) – The Fuel Tester collects these samples. Get the Fuel Oil sample from the Fuel Tester once per month. Store the sample in a well marked clean glass container. Label the sample as No. 6 Fuel Oil and fill out the appropriate Chain-of Custody.

Black Liquor (Quarterly) - The Fuel Tester collects these samples each week. Get a Black Liquor sample from the Fuel Tester once per quarter as opposed to weekly. The sample is to be placed into a clean glass jar provided by the lab. Label the sample as Black Liquor and fill out the appropriate Chain-of Custody.

Coal (Annual) - The Fuel Tester collects these samples. Get the coal sample from the Fuel Tester once per year. Store the sample in a well marked clean container. Label the sample as Coal and fill out the appropriate Chain-of Custody.

TDF (Annual) – You can use a portion of the monthly TDF sample for this annual sample.

Preservative: None of the samples need to be preserved or shipped on ice.

Shipping: Send the samples to ALS for analysis on a monthly basis. **Fuel Oil samples and Black Liquor samples must be shipped separately and must be accompanied by their MSDS's. Talk to the Shipping Department before sending Fuel Oil or Black Liquor samples. The TDF, sludge, woodwaste, pellet fuel, and coal samples can be shipped together.** All Samples should be shipped Fed Ex Overnight as some are considered hazardous and Accounting wants the results as asap.

ALS
3860 S. Palo Verde Rd., Suite 302
Tucson, Arizona 85714

Holding Time: Six Months

Call Adam Becker @ 2929 with any questions. ALS can be contacted at 520-573-1061 or contact Wendy Hyatt at Wendy.Hyatt@alsglobal.com.

APPENDIX C -
GHG INSPECTION & MAINTENANCE PLAN

Inspection and Maintenance Plan for Title V and Greenhouse Gas Compliance

File 8.24.4

Note: See Other Tab for the Title V I&M Plan

2017

Area	Equipment	Required Preventative Maintenance	Functional Location PM is written to	Frequency of Work	Who Performs the Work	Maintenance Plan Numbers/Recordkeeping
Kraft Mill	Lime Kiln #6 Fuel Oil Flow Meter Rosemount Model 3051C dP Flowmeter	Calibrate meter to loop sheet specs. Verify signal to Foxboro.	EM-CRC-LKN1-290400	Annually when burning fuel oil	Kraft Mill E&I Technicians	55563
Kraft Mill	Lime Kiln to PCC Plant Flue Gas Flow Meter Rosemount Annubar 3051SFA1G300ZSHPH2T100T31DA1A5Q4M5 29-FX-0458	Calibrate meter to loop sheet specs. Verify signal to Foxboro.	EM-UTL-COMP-290458	Annually	Kraft Mill E&I Technicians	63431
Boilerhouse	No. 8 Boiler #6 Fuel Oil Flow Meter Moore 340D2AH12BNNN13	Calibrate meter to loop sheet specs. Verify signal to Foxboro.	EM-PWB-BL08-130105	Annually	BoHo E&I Technicians	55562
	No. 8 Boiler Natural Gas Flow Meter Moore 344BN5N1N	Calibrate all 4 transmitters, 13-DP-103B, 13-DP-103A, 13-TX-0103, 13-PX-0103	EM-PWB-BL08-130103	Annually	BoHo E&I Technicians	54202
	#6 Fuel Oil Tank Level Indicator Rosemount Model 3051S1LD3AA.... (Flange Mounted) New in 3/13/12	Calibrate Transmitter to loop sheet specs. Verify Signal in Foxboro	EM-PWB-BL08-130144	Annually	BoHo E&I Technicians	54203
	No. 9 Boiler Natural Gas Flow Meter Moore 340DDBHABBNN213	Calibrate Transmitter to loop sheet specs. Verify Signal in Foxboro	EM-PWB-BL09-030108	Annually	BoHo E&I Technicians	54204
	No.11 Boiler Natural Gas Flow Meter Rosemount 1151EP4E22M2B3L1	Calibrate Transmitter to loop sheet specs. Verify Signal in Foxboro	EM-PWB-BL11-682804	Annually	BoHo E&I Technicians	54187
	No. 10 Rec Furnace BLS Flow Yokogawa 210DN-AA1-LSA/ND & two Yokogawa ADMG AXR040G-E1AH1L-CA11-21B (recirc).	There are 3 Mag Flow Meters. These meters are sent to the manufacturer for calibration. This was last done on 10/14/09. The two recirc flow meters were installed calibrated in October of 2012.	EM-CRB-BL10-150203 EM-CRB-BL10-150210	As needed	Outside Source (Graftel, Inc in Elk Grove Village, IL did it last)	54206
	No. 10 Rec Furnace #6 Fuel Oil Flow to Aux Burners Rosemount 3051CD2A22AIAJI	Calibrate Transmitter to loop sheet specs. Verify Signal in Foxboro	EM-CRB-BL10-150407	Annually	BoHo E&I Technicians	54188
	No. 11 Boiler CO2 Analyzer Sick Model GM 35-3 L-68-0516	Perform quarterly cylinder gas audits and maintain as necessary. There is a 3 month PM on this as well.	EM-PWB-BL11-680516	Quarterly CGAs and /or annual RATAs plus there is a 3 month PM on this	BoHo E&I Technicians	56031