U.S. Department of Energy/Placer County Biomass Utilization Pilot Project
DE-FG36-08GO88026
Phase I Report

Air/Water Emissions and Carbon Credits/Emissions Offsets Task 1.0

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1.0 Introduction

This first task (Task 1.0) of the U.S. Department of Energy (DOE) award No. DE-FG36-08GO88026 is to study potential air/water emissions and carbon credits/emission offsets for the successful deployment of a 1 to 3 megawatt woody biomass fueled bio-energy facility in the Lake Tahoe Region (LTR). Such a facility is critical to serving the hazardous forest fuels reduction programs in the LTR in future years.

This task and its subtasks determine how projected air and water emissions from the bio-energy project will be offset to conform to air quality and water quality regulations. Both criteria air pollutants and greenhouse gas (GHG) emissions are quantified using data from previous Placer County Air Pollution Control District (PCAPCD) projects, technology vendor information and data, and other relevant sources. Emissions from open in-forest pile burning of biomass are compared against those from the bio-energy project. The anticipated reduction in emissions due to processing for bio-energy conversion may yield offset credits for mitigation, which could be critical to the permitting process of a bio-energy project in the LTR. The following Tasks and Subtasks were agreed to by Placer County and the DOE in 2008 for the scope of this report. The agreed upon tasks were modified in 2011 to reflect a change from the original project site of Kings Beach, CA which was within the Lake Tahoe Basin (LTB) to the alternative site located within the Eastern Regional Landfill (now inactive and a.k.a. Cabin Creek) area just outside the LTB by the Placer County Board of Supervisors. The reason for the site location change was due to the generation of noise levels above ambient levels that could not be adequately mitigated. All of the analyses for both sites are included in this report.

The emissions/offset study consists of several subtasks as outlined below (as agreed to in DOE approved work plan):

<u>Subtask 1.1 (Section 2.0)</u> – Determine criteria air pollutant and GHG emissions from the bio-energy project, using process operations selected from the bio-energy conversion technology assessment. Emissions include those from the biomass removal, processing (chipping/grinding), and transport. Also, the impact of processing biomass fuel at the Placer County Cabin Creek Transfer Station and other potential processing facilities will be assessed. This subtask will ultimately be connected to the "New Source Review Permit Analysis" to be conducted in the project's Task 6.

<u>Subtask 1.2 (Section 3.0)</u> – In coordination with the "Woody Biomass Fuel Source Analysis" study (Task 7), estimate the amount of biomass, location, and distance from Kings Beach:

- Current available and planned, wood biomass slash piles within the LTR.

- Future available biomass fuels generated from the wildland/urban interface (WUI) in the LTR.
- Biomass fuels currently being transported to biomass energy facilities outside the LTB (i.e. the biomass plant at Loyalton, CA).

Subtask 1.3 (Section 4.0) – This subtask quantifies air emissions that are avoided as the result of the LTR bio-energy project, based on the bio-energy results of Subtask 1.2:

- Open, in-forest, and pile burning of wood biomass slash piles.
- Power generation from fossil fuels plants that is displaced by the proposed LTR facility.
- Reduction in the occurrence and/or intensity of forest fires as a result of forest biomass thinning operations that are supported by the LTR project. This will be assessed to the extent possible, based on the progress of currently on-going research efforts being sponsored by the United States Forest Service (USFS) and the PCAPCD.
- Transporting biomass fuels to bio-energy energy facilities outside of the LTB (i.e. the bio-energy plant at Loyalton, CA).

Subtask 1.4 (Section 5.0) – The increased rate of carbon sequestration in the LTR treated forest as the result of the bio-energy sponsored forest biomass fuel thinning activities is quantified -- to the extent possible relying on the USFS research efforts mentioned above in Subtask 1.3.

Subtask 1.5 (Section 6.0) – Projected GHG emissions offset credits from the LTR project to assist in development of procedures to validate the offset credits. This subtask will ultimately be connected to the "New Source Review Permit Analysis" to be conducted in the project's Task 6 of the Phase I DOE Grant.

Subtask 1.6 (Section 7.0) –The feasibility of establishing a local Placer County GHG Offset Credit Trading market, with emphasis on activities including forest fuel thinning for improved forest health, and diversion of bio-energy conversion that would have otherwise been consumed in the field is outlined in this section.

Subtask 1.7 (Section 8.0) – LTR bio-energy project water requirements, water availability, and wastewater discharge for the different technologies described in Section 2.1 are to be examined.

2.0 Determination of Criteria Air Pollutants and GHG Emissions

Air emissions from bio-energy conversion systems include:

- Particulate matter with diameter less than 10 microns (PM10). Result from inorganic, non-combustible constituents in the biomass fuel, and the formation of soot and organic compounds from incomplete conversion of the biomass fuel. Inhalation of fine particulate causes damage to human respiratory and circulatory systems. Fine particulate emissions also impact water quality.
- Nitrogen oxides (NOx). Forms during high temperature reactions from nitrogen in the biomass fuel and nitrogen in the supplied air. Responsible for the formation of ground level ozone and smog.
- Carbon monoxide (CO). Results from the incomplete conversion of the organic content of the biomass fuel.
- Volatile organic compounds (VOC). Form in a similar manner to CO. Responsible for ground level ozone and smog.
- Sulfur oxides (SO_2). Form from the sulfur content of the biomass fuel. Because the sulfur content of conifer forest waste derived biomass used in the Kings Beach plant is very low, SO2 emissions are not considered in this report.
- GHG, including carbon dioxide (CO2) and methane (CH4). Result from the conversion of the carbon in the biomass fuel.
- Air toxics. Trace levels of inorganic and organic air toxics depend on biomass composition and conversion technology design. Air toxics from the bio-energy conversion units considered for this project will be very low due to the utilization of virgin conifer forest derived biomass wastes, and the use of state of the art conversion and control technology. Air toxics are not considered in this report.

The emissions levels and control methods, for the criteria air pollutants (including PM10, NOx, CO, VOC, and SO2), and air toxics, are critical information needed to demonstrate compliance with PCAPCD and Tahoe Regional Planning Agency (TRPA) rules and regulations.

2.1. Description of Bio-energy Power Technologies for Evaluation

Biomass, such as woody wastes from forest residues can be supplied to energy conversion systems and converted to useful steam, heat, or combustible gases.

These energy conversion systems vary widely but fall under two basic types, gasification[1] and direct combustion[2] for electricity generation. These two types are the focus of the emissions study conducted as part of this task.

Direct combustion / steam cycles produce electricity at an efficiency of around 15 - 20%; and gasification / internal combustion cycles are projected from 20 – 35% depending on gasification technology selected. Both of these are conservative estimates.

Other technology systems for biomass conversion to electricity, such as fuel cells are neither currently economically available nor projected to be available within the proposed timeframe of this project (operations in 2014)

Unlike larger-scale biomass to electricity systems (10 MW or larger), of which there are scores of in the United States and internationally, the number of operating small-scale biomass to electricity facilities appears much less. Table 2-1 below displays some of the small-scale biomass to electricity facilities found domestically and internationally.

The two basic technologies, gasification and direct combustion, are further detailed in Section 2.1.1 below.

2.1.1. Gasification

Gasification is the thermo-chemical conversion of organic solids and liquids into a synthetic gas (syngas) under very controlled conditions of heat and strict control of air or oxygen. The syngas formed by gasification is composed primarily of hydrogen (H_2), methane (CH_4), and carbon monoxide (CO). Gasification also produces carbon char (also commonly named 'bio-char') and ash that remain as solids and may be used for commercial products (e.g., ash as a soil amendment).
The syngas can be used as a primary fuel in electrical generating units such as a reciprocating internal combustion engine or in a gas turbine. It can also be used as fuel to produce steam or hot water for heating and/or manufacturing processes. In addition to producing syngas from biomass, there are several processes and technologies attempting to produce commercially viable liquid

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[1] *Gasification systems generate electricity through combustion of syngas in an internal combustion engine or turbine generator. Electricity generation efficiency can range from 20 – 35%.*

[2] *Direct combustion systems generate electricity through the production of steam in a boiler, and utilization of the steam in a steam turbine. For units on the scale of the scale of the Kings Beach operation, electricity generation efficiency is on the order of 15-20%.*

fuels such as ethanol and “green” diesel from biomass (also known as bio-diesel).

Exhibit 2-1 illustrates a typical process flow diagram for a gasification system.

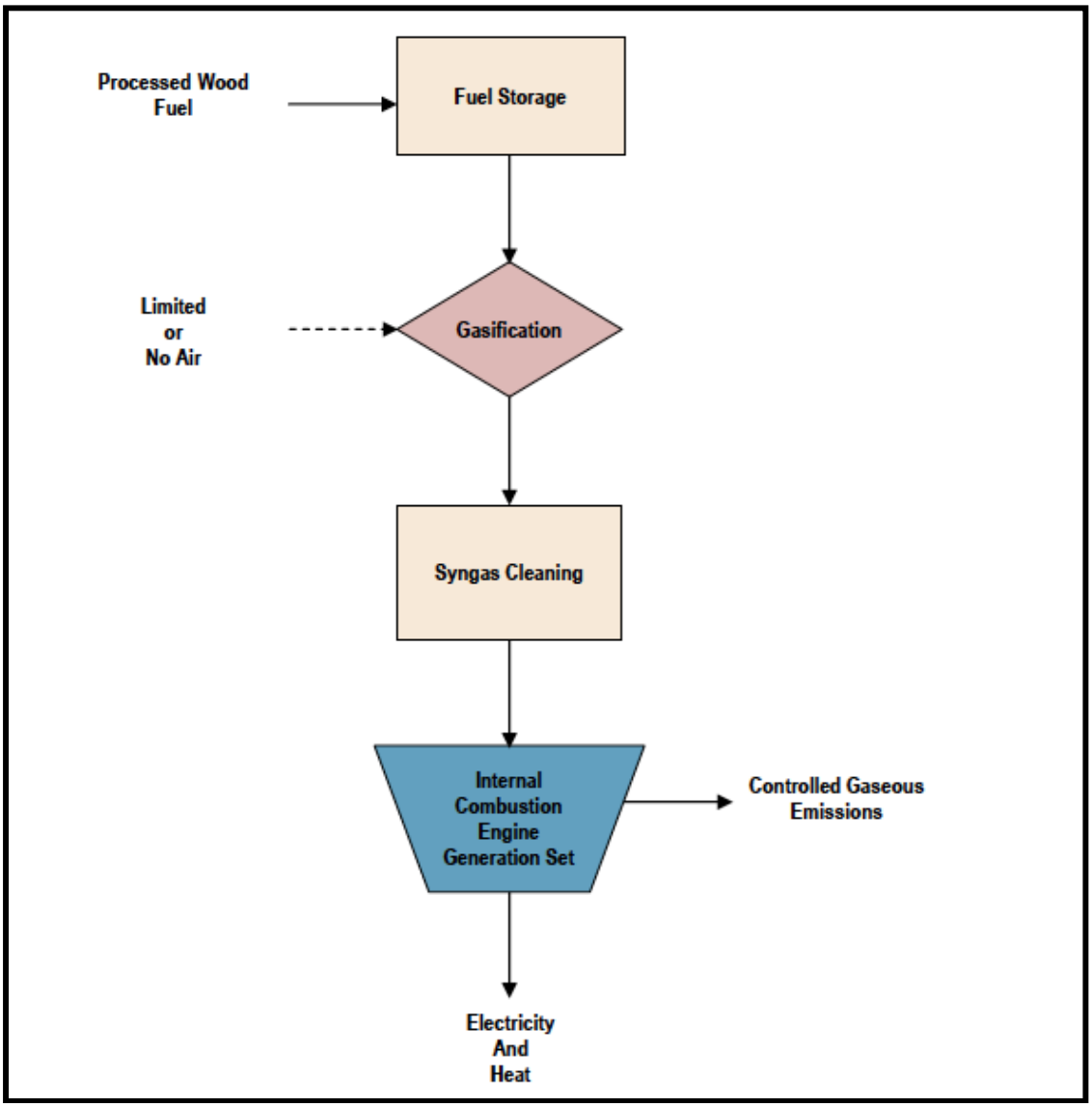

Exhibit 2-1 Small Gasification System Process Flow

Table 2-1 Small-Scale Biomass to Electricity Systems

Biomass Gasification to Electricity – Small Scale Systems				
Facility	**Location**	**Type/Size**	**Manufacturer/Vendor**	**Notes**
Phoenix Merced	Merced, CA	500 KW	Ankur/Phoenix Energy	System fully constructed awaiting interconnect with PG&E in 1/11
Phoenix Oakdale	Oakdale, CA	1 MW	Ankur/Phoenix Energy	Permitting completed. Construction to begin 1st Quarter 2011
Nexterra Product Development Center	Kamloops, BC	250 KW	Nexterra	This is a test unit to verify syngas cleanup and use in Jenbacher IC engine. As of 10/10
Dixon Ridge Farms	Winters, CA	50 KW	Community Power Corporation	Fueled by nut shells
Biomassenkraftwerk Güssing	Güssing, Austria	2MW	Repotec/Austrian Energy	Wood chips
Pyrotherm Güssing	Güssing, Austria	350 KW	Pryoforce/CTU	Waste wood from flooring factory. Uses Jenbacher J312 ICE
Energie Oberwart	Oberwart, Austria	2.7 MW	Ortner Anlagenbau	Wood chips
Harboore CHP Plant	Harboore, Denmark	1.4MW	BW Volund	Woodchips
Gjol Kraftvarmevaek	Gjol, Denmark	500 KW	TK Energi A/S	Woodchips
Tervola	Tervola, Finland	500 KW	Entimos Oy	Wood waste
NOVEL	Kokemaki, Finland	1.8 MW	Condens Oy	Uses 3 IC engines
Nidwalden	Nidwhalden, Switzerland	1.2 MW	Pyroforce	Uses waste/demolition wood. Electricity via Jenbacher ICE
Woodpower Wila	Wila, Switzerland	350 KW	Dasagren/Netpro	Waste wood. Electricity via Jenbacher ICE
PRM Rossano	Rossano, Italy	3.8 MW	PRM Energy Systems	Uses waste wood and olive pits.
PRM Moissanes	Moissannes, France	3.8 MW	PRM Energy Systems	Uses waste wood
Ankur	India (several)	25 to 400 KW	Ankur Scientific	Various biomass fuels

Biomass Direct Combustion to Electricity – Small Scale Systems[1,2]				
Northern NV Correctional Center	Carson City, NV	1.2 MW	APS	Used wood waste. Ceased operations in Summer 2010. Currently seeking buyer
Kankaanpaan Kaukolampo	Kankaanpaa, Finland	6 MW		Peat and wood waste
Kuusamo Power Plant	Kuusamo, Finland	6.1 MW	Fortum Oyj	Peat and wood waste
Lomma Power Plant	Lomma, Sweden	3.5 MW		Wood and paper
Mala Power Plant	Mala, Sweden	3 MW		Waste wood
Ludwigsfelde CHP Plant	Ludwigsfelde, Germany	1.5 MW	Thenegro	Waste wood
Zelezniki CHP Plant	Zelezniki, Slovenia	600 KW		Waste wood

[1] These are facilities not located within a sawmill or other wood products manufacturing building.

[2] These are just examples – there are many small direct combustion CHP plants around the world

The earliest uses of gasification date back to the production of city gas from coal in the late 1800's. Gasification has been in commercial use for more than 50 years with the production of syngas (as a substitute for natural gas). More recently, gasification has been applied to power generation at a few large integrated gasification combined cycle (IGCC) plants in the U.S. and others outside the U.S. with coal as the fuel.

There are several variations on biomass gasification systems, but general fall into one of the two common types - updraft or downdraft gasifiers.

Updraft gasifiers consist of a fixed bed of biomass fuel through which the "gasification agent" (steam, oxygen and/or air) flows in counter-current configuration. Thermal efficiency is high as the gas exit temperatures are relatively low. However, this means that tar and methane production is significant at typical operation temperatures, so product gas must be extensively cleaned before use. The tar can be separated from the syngas in scrubbers and collected and recycled to the gasification reactor.

Downdraft gasifiers are similar to the counter-current type, but the gasification agent gas flows in co-current configuration with the fuel (downwards, hence the name "down draft gasifier"). The produced gas leaves the gasifier at a high temperature, and most of this heat is often transferred to the gasification agent added in the top of the bed, resulting in energy efficiency on level with the counter-current type. Since all tars must pass through a hot bed of bio-char in this configuration, tar levels are much lower than the counter-current type and thus the syngas require less cleaning.

Bio-energy-based syngas delivered to an IGCC process allows for significant efficiency increases over direct combustion energy production. However, gasification of biomass fuel feedstocks is not as commonly applied as IGCC within the U.S. Gasification of biomass resources is currently on the upswing in Europe and there is much interest in the U.S. Advanced technologies are beginning to produce biomass-based syngas at rates that are competitive with natural gas rates and traditional direct combustion biomass energy production.

2.1.2. Direct Combustion

In direct combustion systems, the biomass fuel is directly burned (combusted) in some type of furnace or combustion unit that then supplies heat to a boiler. Nearly all commercial biomass power applications today use boilers in conjunction with a steam turbine to generate electricity. Common boilers used

for biomass direct combustion systems include traditional stoker boilers[3] and bubbling fluidized bed boilers[4]. Each boiler technology allows for and requires differing fuel specifications, which requires careful analysis to select boiler technology that is appropriate for available fuels and project conditions.

Exhibit 2-2 below illustrates a direct combustion system flow process.

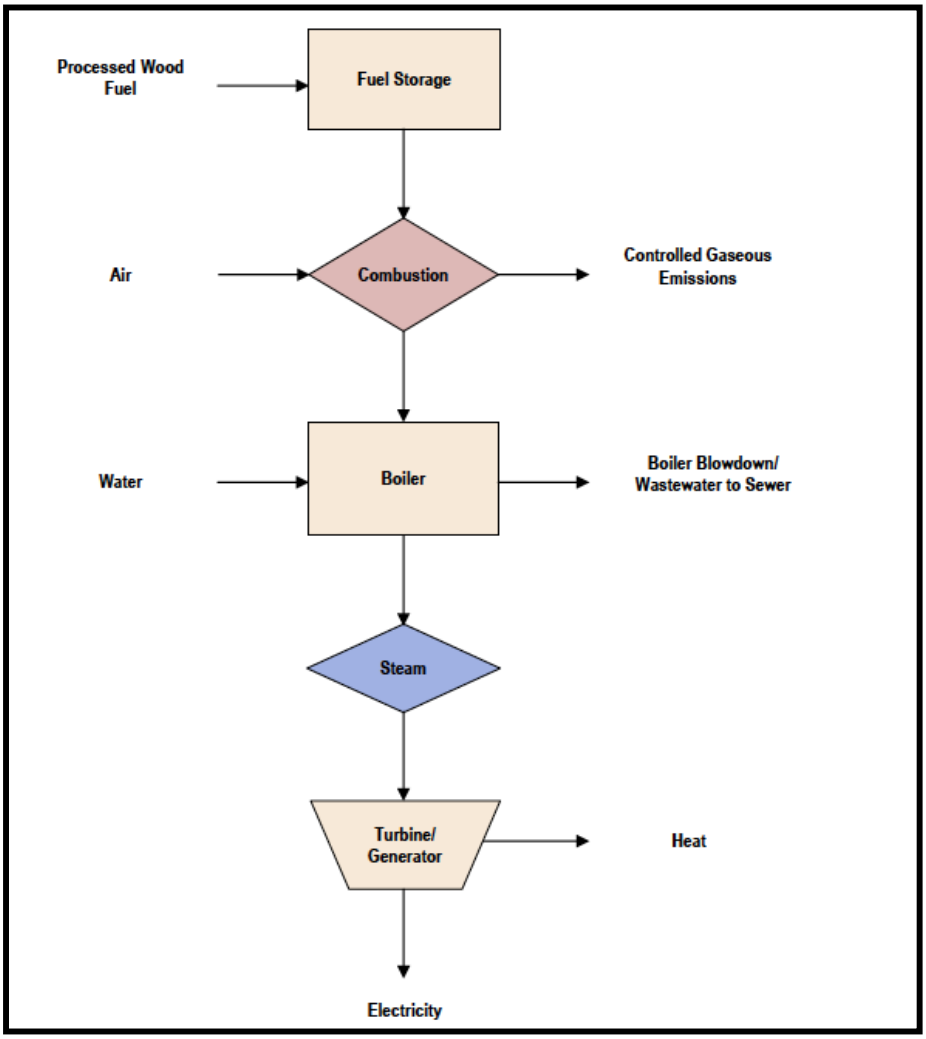

Exhibit 2-2 Direct Combustion System Process Flow Design

[3] *In stoker boilers, wood chips burn on a grate, with combustion air supplied both from under the grate and above the burning bed.*

[4] *In fluidized bed boilers, wood chips burn in a suspension with inert materials, forced through upward air jets.*

2.1.3. Specific Technology Emissions to be Evaluated

Since 2008, ongoing technology assessment activities have been reviewing numerous small-scale gasification and direct combustion technologies to determine how technologies are in, or entering, the market place that can meet the air and water emissions goals of the Placer County Biomass Utilization Pilot Project. The technology assessment has sought to find representative technologies that could meet the air emissions necessary for siting in the Lake Tahoe Basin as well as outside of the basin (within the Basin the siting requirements are more stringent), and also have very low water supply and discharge requirements. With various technical information requests and direct contact with various vendors of biomass to electricity technology, it was determined that the following three technologies represented potential candidate technologies for use at the LTR bio-energy facility site:

- Nexterra – A Vancouver, British Columbia based company specializing in woody biomass gasification. Currently, Nexterra has several bio-energy thermal gasification projects in both the U.S. and Canada. At their Kamloops (B.C.) Product Development Center Nexterra is conducting a long term test of woody biomass gasification, whereby the syngas produced is used in an internal combustion engine (250 KW Jenbacher). This test has over 1400 hours of run time to date on the IC engine using woody biomass produced syngas. Some of Nexterra's other project can be seen Table 2-1. Nexterra (and partners) is currently developing several biomass to electricity projects in BC and the U.S.
- Phoenix Energy – A San Francisco, CA based company specializing in woody biomass gasification, with principal emphasis on producing electricity for co-located use or transmission to the grid. Phoenix is currently starting up a 500KW gasification system in Merced, CA, using local woody biomass waste. Phoenix is also about to site a 1 MW unit at an agricultural woody waste facility in the Central Valley. Waste heat from the electrical generating system will be also used to dry food and feed processing wastes. Phoenix also has several other California projects in various stages of development.
- Envio Energie - The sole North American design, marketing and manufacturing licensee for KMW Energi, a market and technology leader in Scandinavia in biomass combustion plants. Although Envio Energie does not have an operating KMW system in the U.S. as yet, several are reported under development. KMW Energi has scores of their direct combustion units operating in Europe.

Nexterra

Nexterra uses technology that gasifies biomass into syngas, and then proposes to send that syngas in an internal combustion engine. Major advantages of Nexterra's proposal include the high thermal efficiencies of internal combustion versus direct combustion technology, while a major drawback is that the technology system is not yet widely dispersed in the U.S.

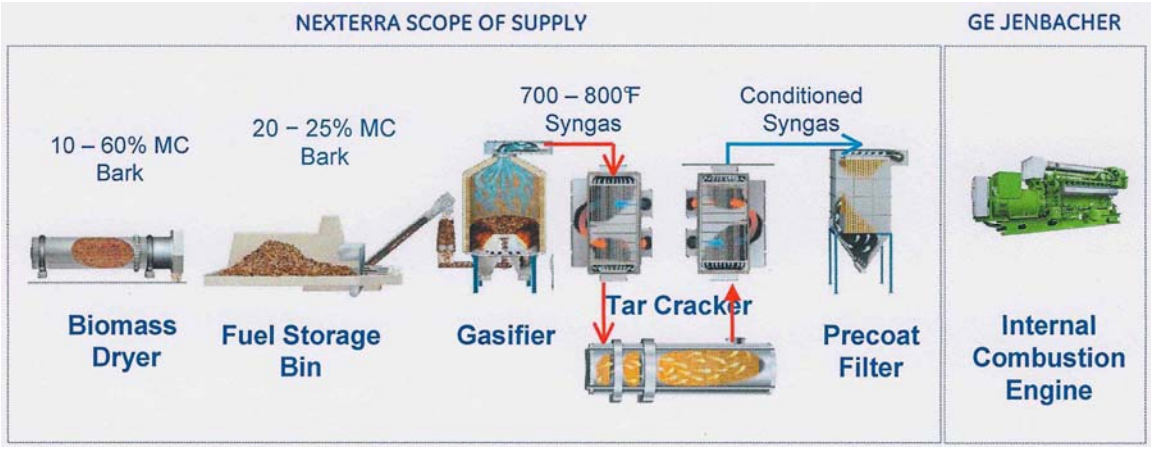

Exhibit 2-3 Nexterra Gasification System

Nexterra's technology proposes gasifies biomass in their proprietary gasifier that partially oxidizes the biomass material at high temperatures (1500-1800 °F) and long residence times. The raw syngas is then delivered to a tar cracker and filter for processing before being delivered to an internal combustion engine. Nexterra uses a GE Jenbacher internal combustion engine, a "lean-burn" engine[5], which connects to an electrical generator to produce electricity. Nexterra has confirmed an agreement with GE to use the Jenbacher engine on clean syngas from their proprietary process.

[5] *The Nexterra unit utilizes a "lean-burn" internal combustion engine, where operation involves supplying a sufficient excess of air for the combustion of the syngas, acting to minimize NOx formation through diluting, and cooling, the combustion zone. For additional NOx control, selective catalytic reduction would be required.*

Air Emissions

Air emissions for Nexterra's gasification technology combined with a Jenbacher IC engine, and selective catalytic reduction[6] (SCR) control, were estimated for a 2 MW facility:

- CO 6.5 lb/hr (26 tons/year)
- NO_x 0.5 lb/hr (2.1 tons/year)
- SO_2 0.01 lb/hr (0.04 tons/year)
- VOC 3.0 lb/hr (11.8 tons/year)
- PM10 0.6 lb/hr (2.4 tons/year)

The emissions estimates are based on emissions factors from U.S. EPA AP-42[7] emission factors handbook (Chapter 2.4, Table 2.4-5, landfill gas IC engines and Chapter 3.2, gas fired reciprocating engines), engine performance specifications literature from Jenbacher on their Type 6 engine, and discussions with Nexterra. It has been conservatively assumed that SCR will lower the NOx by 85%.

Phoenix Energy

Phoenix Energy's gasification process is similar in general concept to Nexterra. The Phoenix Energy system is distinctly different than the Nexterra model in how it handles biomass feedstock. The Phoenix technology is a downdraft gasifier[8] that contains all the components of the process in a vertical column. Feedstock enters the top of the vessel where drying occurs. The next section of the process vessel is where pyrolysis[9] occurs and combustible hydrogen and methane are released from the feedstock in a partial oxidation reaction. This is the syngas that is produced from the pyrolysis reaction. Feedstock continues further down the vessel where it further decomposes and ash exits the bottom of the vessel. Ash collected here can then be stored and removed from site. Gases and fly ash are blown into filters which removes ash components and the syngas is then enters the combustion chamber.

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[6] *Selective Catalytic Reduction (SCR) involves reduction of NOx through introduction of ammonia in the presence of a precious metal catalyst at temperature approx. 700F*

[7] *AP-42 is an U.S. EPA compendium of default emission factors used for air quality permitting and compliance. It is used in lieu of emissions testing, particularly for planned projects that do not yet have emissions testing performed.*

[8] *In a down-draft gasifier biomass fuel is fed from the top of the unit and syngas exits at bottom*

[9] *Pyrolysis involves the thermal breakdown of organic constituents in the absence of oxygen.*

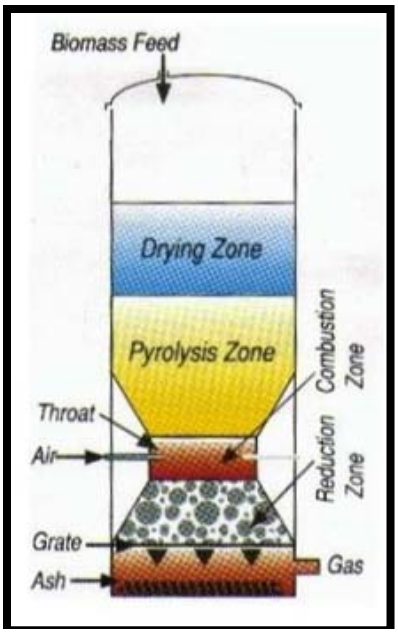

Exhibit 2-4 Phoenix Energy Concept Diagram

Phoenix uses this downdraft orientation of their technology for more full oxidation of biomass feedstock leading to more full reduction of tar in the syngas compared to updraft orientation gasifiers. Phoenix states that there is a 99% reduction in tars compared to updraft gasifiers and fluidized bed gasifiers. Syngas cleanup is conducted using a low-volume and recycled water scrubber.

Unlike the Nexterra unit, Phoenix Energy does not specify a particular favorable IC engine that is preferential for their system. The rich burn engine is configured with a three-way catalytic converter[10] for control of NOx, CO, and VOC emissions.

Air Emissions

Phoenix Energy has committed to meeting the following emissions from its gasifier and associated IC engine, scaled to a 2 MW facility[11]:

- CO 3.4 lb/hr (13.39 tons/year)
- NOx 0.64 lb/hr (2.58 tons/year)

[10] *The Phoenix unit utilizes a "rich-burn" internal combustion engine, involving minimizing (starving) the air to combust the syngas. This allows for the use of a three-way catalytic converter to reduce NOx, CO, and VOCs.*

[11] *Authority to Construct Engineering Evaluation, San Joaquin Valley Air Pollution Control District, 7/28/08 – Assume 7,644 operating hours per year*

- SO2 0.05 lb/hr (0.19 tons/year)
- VOC 0.64 lb/hr (2.58 tons/year)
- PM10 0.3 lb/hr (01.2 tons/year)

Envio Energie

Envio Energie (Envio) technology in essence is a modified version of a stoker grate furnace system[12]. Envio has developed their technology in Sweden and Norway and has a significant number of facilities in operation in Scandinavia. Since 1984, Envio has developed over 100 facilities in Norway and Sweden, mainly heat and steam plants. Envio installed their first CHP[13] plant in 2005.

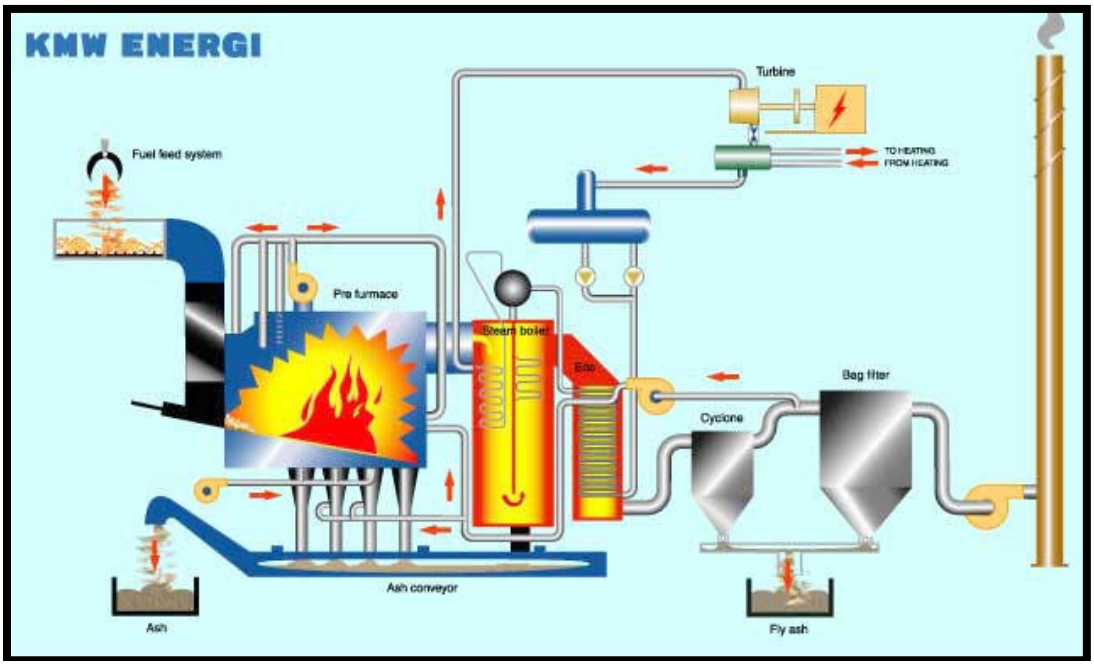

Exhibit 2-5 Envio Boiler System Schematic

[12] *The entire bottom of the furnace is a slow moving platform or conveyor forming the grate*
[13] *Combined Heat and Power (CHP) is the use of a heat engine or a power station to simultaneously generate both electricity and useful heat, also known as cogeneration.*

Air Emissions

The Envio system has the following emissions for a 2 MW facility, based on vendor supplied emissions data from source tests on European units and engineering performance estimates[14]

- CO 5.6 lb/hr (22.6 tons/year)
- NO_x 2.24 lb/hr (9.05 tons/year)
- SO_2: Negligible
- VOC 0.24 lb/hr (0.96 tons/year)
- PM 0.56 lb/hr (2.3 tons/year)

The emissions estimates are shown assuming the use of a baghouse[15] for particulate matter (PM) control, and the use of SNCR[16] for NOx control, which is commercially available and well demonstrated for NOx control in bio-energy units, and is assumed to reduce the NOx level by 60%.

2.1.4. Residual Waste Heat Utilization

Existing buildings in Kings Beach and planned future buildings are candidates for the sale of residual heat (a.k.a. waste heat). Information concerning these buildings was provided by the Placer County Redevelopment Agency. Existing buildings are probably using natural gas, propane or electricity for space heating and other heating needs. These buildings have lower potential as customers for residual heat from the facility since conversion from existing systems to a high-temperature (HTW) hot water heating system can be expensive. New buildings, however, can be designed to utilize HTW and are therefore more likely candidates. This would be the similar situation at the Cabin Creek site, except no new buildings are planned.

The potential for using waste heat for existing and future buildings at the various alternative bio-energy facility sites is evaluated in detail in the Task 4 report ("Siting Analysis for Small-Scale Biomass Combined Heat and Power in the LTR"). Alternative sites to the Kings Beach site, located at the Cabin Creek Transfer

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[14] *Emission limits are based on an assumption of clean fuel that has a composition of 49% carbon, 6% hydrogen, 43% oxygen, 0.3% nitrogen, and 1.7% ash*

[15] *A baghouse has fine porous filter bags that removed particulate from the exhaust gas similar to that in household vacuum cleaner.*

[16] *Selective Non-Catalytic Reduction (SNCR) involves reduction of NOx through introduction of ammonia at a temperature of approx. 1500F.*

Station, Tahoe City (former quarry), and the Burton Creek Government Center are also evaluated for their potential in the Task 4 report.

Another potential use of residual heat, which is not necessarily site specific could be the use of an Organic Rankine Cycle (ORC) engine to produce additional electricity. An ORC uses the waste heat to heat a fluid which will boil into a gas to drive an electrical turbine. Such a system is completely enclosed, with no combustion, and thus no air emissions. Electrical production using this waste heat could exceed 100 kW or more depending on the technology employed by the LTR bio-energy facility.

2.2. Air Emissions Calculations

The criteria air pollutants such as nitrogen oxides (NOx), carbon monoxide (CO), particulate matter less than 10 microns (PM10), and volatile organic compounds (VOCs), along with GHG (including carbon dioxide (CO2) and methane (CH4)) and GHG emissions of the three technologies described in Section 2.1 are presented in Tables 2-2, 2-3, and 2-4 below.

The top half of Table 2-2 summarizes air pollutant emissions for the Envio Energie direct combustion system operations -- for system electricity outputs of 2 and 3 MW:

- Envio bio-energy unit, including uncontrolled (prior to air pollution control system) and controlled (at the stack) emissions with use of baghouse and SNCR, with electricity production efficiency of 16%.
- Fuel is solely excess biomass waste from local forest management thinning operations, consisting of conifer limbs and tops and surface fuels (brush). The fuel is assumed to have heat value of 8,000 Btu/dry lb.
- Permitting thresholds for the requirement for Best Available Control Technology (BACT) and Emission Offsets for Placer County Air Pollution Control District and Tahoe Regional Planning Agency.
- Biomass processing, involving in-field grinding of bulk biomass into chips using portable chipper with an assumed processing efficiency of 0.2 BDT/HP-hr.
- Biomass transporting from the field harvest location to proposed Kings Beach (or Cabin Creek) bio-energy energy facility in chip vans (16 wet ton capacity with a van mileage of 4.5 miles/gallon of diesel). It is estimated that average transportation distance from the field to the energy plant is 25 miles one-way – for either the Kings Beach or Cabin Creek locations being considered.

- Biomass transporting from the field harvest location to the Tahoe Regional Bio-energy facility. It is estimated with the use of chip vans with 16 wet ton capacity with a van mileage of 4.5 miles/gal of diesel. It is estimated that average transportation distance from the field to the energy plant is 25 miles one-way – for either the Kings Beach or Cabin Creek locations being considered.

Table 2-3 summarizes similar information for the Phoenix gasification system operations. The system is assumed to have an electricity production efficiency of 23%.

Table 2-4 summarizes similar information for the Nexterra gasification system operations. The system is assumed to have an electricity production efficiency of 32%.

Table 2-5 summarizes the three systems emissions and compares them to the thresholds of both the PCAPCD and TRPA BACT and the need for emissions offsets thresholds.

Emissions factors, and other assumptions, that have been used for the emissions analyses of this section are provided in Appendix C.

Table 2-2 Summary of Envio Air Emissions Calculations

	Air Emissions (tons per year)									
	2 MW					3 MW				
	NOx	PM10	VOC	CO	CO2	NOx	PM10	VOC	CO	CO2
TAHOE REGIONAL BIOMASS PLANT										
Envio, Direct Combustion, Steam										
Uncontrolled	22.6	22.30	0.96	22.6	39076	33.9	33.45	1.44	33.9	58615
Controlled	9.0	2.23	0.96	22.6	39076	13.6	3.35	1.44	33.9	58615
Permitting Thresholds										
BACT										
PCAPCD -- Cabin Creek & Kings Beach	1.8	14.60	1.80	100.4	--	1.8	14.60	1.80	100.4	--
TRPA	1.2	0.80	3.20	4.0	--	1.2	0.80	3.20	4.0	--
Offsets										
PCAPCD -- Kings Beach	0.0	0.00	0.00	0.0	--	0.0	0.00	0.00	0.0	--
PCAPCD -- Cabin Creek	10.0	15.00	10.00	99.0	--	10.0	15.00	10.00	99.0	--
TRPA	4.4	4.00	22.90	40.2	--	4.4	4.00	22.90	40.2	--
Biomass Processing and Transport										
Tub Grinder	1.5	0.06	0.08	2.0	291	2.3	0.09	0.12	3.0	437
Chip Van Transport	2.1	0.05	0.06	4.9	272	3.1	0.07	0.09	7.3	408
TOTAL	12.6	2.34	1.10	29.5	39640	19.0	3.51	1.65	44.2	59460
BASELINE WITHOUT BIOMASS PLANT										
Open Pile Burning	60.7	151.85	101.23	1265.4	37123	91.1	227.78	151.85	1898.1	55684
Displaced Power, Existing Grid	0.6	0.35	0.03	0.6	7534	0.9	0.52	0.05	0.9	11300
TOTAL	61.3	152.20	101.27	1266.0	44656	92.0	228.30	151.90	1899.0	66984
Emission Reductions	48.7	149.86	100.17	1236.5	5017	73.0	224.79	150.25	1854.8	7525
% Reduction	**79%**	**98.5%**	**99%**	**98%**	**11%**	**79%**	**98.5%**	**99%**	**98%**	**11%**

Table 2-3 Summary of Phoenix Air Emissions Calculations

	Air Emissions (tons per year)									
	2 MW					3 MW				
	NOx	PM10	VOC	CO	CO2	NOx	PM10	VOC	CO	CO2
TAHOE REGIONAL BIOMASS PLANT										
Phoenix, Gasification, IC Engine										
Uncontrolled	2.6	1.2	2.6	13.4	26051	3.9	1.80	3.90	20.1	39077
Controlled	2.6	1.2	2.6	13.4	26051	3.9	1.80	3.90	20.1	39077
Permitting Thresholds										
BACT										
PCAPCD -- Cabin Creek & Kings Beach	1.8	14.60	1.80	100.4	--	1.8	14.60	1.80	100.4	--
TRPA	1.2	0.80	3.20	4.0	--	1.2	0.80	3.20	4.0	--
Offsets										
PCAPCD -- Kings Beach	0.0	0.00	0.00	0.0	--	0.0	0.00	0.00	0.0	--
PCAPCD -- Cabin Creek	10.0	15.00	10.00	99.0	--	10.0	15.00	10.00	99.0	--
TRPA	4.4	4.00	22.90	40.2	--	4.4	4.00	22.90	40.2	--
Biomass Processing and Transport										
Tub Grinder	1.0	0.04	0.05	1.3	194	1.5	0.06	0.08	2.0	291
Chip Van Transport	1.4	0.03	0.04	3.3	181	2.1	0.05	0.06	4.9	272
TOTAL	5.0	1.27	2.69	18.0	26426	7.5	1.91	4.04	27.0	39640
BASELINE WITHOUT BIOMASS PLANT										
Open Pile Burning	40.5	101.23	67.49	843.6	24748	60.7	151.85	101.23	1265.4	37123
Displaced Power, Existing Grid	0.6	0.35	0.03	0.6	7534	0.9	0.52	0.05	0.9	11300
TOTAL	41.1	101.58	67.52	844.2	32282	61.6	152.37	101.29	1266.3	48423
EMISSION REDUCTIONS	36.1	100.31	64.8	826.2	5856	54.1	150.47	97.25	1239.3	8783
% Reduction	**88%**	**99%**	**96%**	**98%**	**18%**	**88%**	**99%**	**96%**	**98%**	**18%**

Table 2-4 Summary of Nexterra Air Emissions Calculations

	Air Emissions (tons per year)									
	2 MW					3 MW				
	NOx	PM10	VOC	CO	CO2	NOx	PM10	VOC	CO	CO2
TAHOE REGIONAL BIOMASS PLANT										
Nexterra, Gasification, IC Engine										
Uncontrolled	14.0	24.10	11.75	26.5	19538	21.0	36.15	17.63	39.8	29307
Controlled	2.1	2.41	11.75	26.5	19538	3.2	3.62	17.63	39.8	29307
Permitting Thresholds										
BACT										
PCAPCD -- Cabin Creek & Kings Beach	1.8	14.60	1.80	100.4	--	1.8	14.60	1.80	100.4	--
TRPA	1.2	0.80	3.20	4.0	--	1.2	0.80	3.20	4.0	--
Offsets										
PCAPCD -- Kings Beach	0.0	0.00	0.00	0.0	--	0.0	0.00	0.00	0.0	--
PCAPCD -- Cabin Creek	10.0	15.00	10.00	99.0	--	10.0	15.00	10.00	99.0	--
TRPA	4.4	4.00	22.90	40.2	--	4.4	4.00	22.90	40.2	--
Biomass Processing and Transport										
Tub Grinder	0.8	0.03	0.04	1.0	146	1.1	0.04	0.06	1.5	218
Chip Van Transport	1.0	0.02	0.03	2.4	136	1.6	0.04	0.05	3.7	204
TOTAL	3.9	2.46	11.82	29.9	19820	5.9	3.70	17.73	44.9	29730
BASELINE WITHOUT BIOMASS PLANT										
Open Pile Burning	30.4	75.93	50.62	632.7	18561	45.6	113.89	75.93	949.1	27842
Displaced Power, Existing Grid	0.6	0.35	0.03	0.6	7534	0.9	0.52	0.05	0.9	11300
TOTAL	30.9	76.27	50.65	633.3	26095	46.4	114.41	75.98	949.9	39142
EMISSION REDUCTIONS	27.0	73.81	38.83	603.4	6275	40.6	110.71	58.25	905.0	9413
% Reduction	**87%**	**97%**	**77%**	**95%**	**24%**	**87%**	**97%**	**77%**	**95%**	**24%**

Table 2-5 Summary of Emissions

	Emissions (Tons per Year)				
	NOx	**PM_{10}**	**VOC**	**CO**	**CO_2**
Biomass Energy Plant – 2 MW					
Gasification -- Nexterra	2.1	2.4	11.8	26.5	19,538
Gasification -- Phoenix	2.6	1.2	2.6	13.4	26,051
Direct Combustion -- Envio	9.1	2.2	1.0	22.6	39,076
Permitting Thresholds					
BACT Threshold					
PCAPCD – Cabin Creek, Kings Beach	1.8	14.6	1.8	100	
TRPA	1.2	0.8	3.2	4	
Offsets Threshold					
PCAPCD – Cabin Creek	10	15	10	99	
PCAPCD – Kings Beach*	---	---	---	---	
TRPA	4.4	4	22.9	40.2	

* Offsets not required by PCAPCD at the Kings Beach site

For a biomass facility located in Cabin Creek, all three technologies are projected to meet PCAPCD emission requirements for the 2 MW size capacity, without obtaining offset credits. For the Envio Energie direct combustion system, for the 3 MW sized unit, NOx emission reduction credits will be required for PCAPCD permitting

For a biomass facility in Kings Beach, the two gasifier/IC engine systems are projected to meet all TRPA and PCAPCD requirements without the need for emission offset credits. For both the 2 or 3 MW plants, the Envio Energie direct combustion system either needs to obtain NOx emission offset credits to meet TRPA regulations or be granted equivalent credit through the reduction of NOx compared with the alternative of open pile burning.

3.0 Estimated Amount of Biomass Fuel Available for Project

The estimated amount of biomass fuel available for the LTR project was determined as part of the project fuel assessment task (Task 7 - "Fuel Procurement Plan for the Lake Tahoe Basin Biomass Energy Generation Facility"). Only strategic, sustainable fuel resources consistent with the project objectives, and compliant with state (California Environmental Quality Act, State of Nevada Title 47 Regulations), regional (Tahoe Regional Planning Agency rules and guidelines), and federal (National Environmental Policy Act) regulations were considered as potentially available fuel.

Results of this fuel assessment concur that there is more than sufficient biomass material available to sustain a proposed 1 to 3 MW bio-energy power generation facility sited at Kings Beach or Cabin Creek, California. As reported in Table 3-1 below there is approximately 112,440 bone dry tons (BDT) per year of biomass fuel practically available within a 30-mile radius of Kings Beach or Cabin Creek (Figure 3-1). Current demand amounts to about 40,350 BDT per year resulting in a net availability of 72,090 BDT per year.

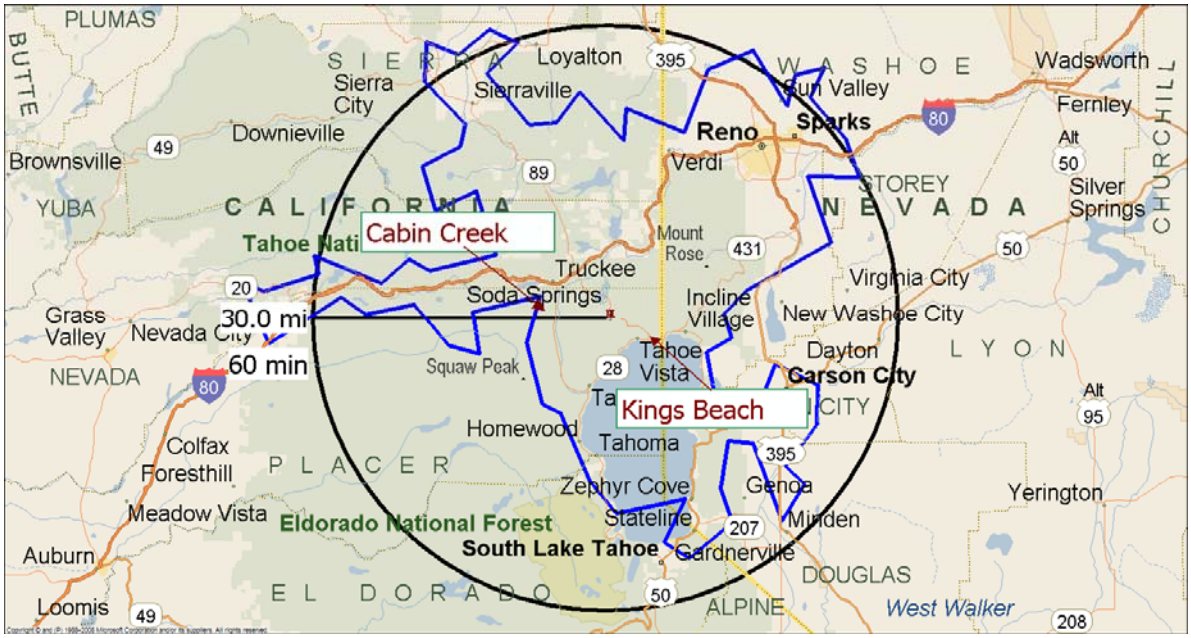

Exhibit 3-1 One hour drive time/30 mile radius

Table 3-1 Practically Available Biomass Fuel by Type For the LTR Project
(Expressed in BDT/Year)

FUEL TYPE	VOLUME
Hazardous Fuels Reduction Residuals – Inside the LTB	16,030
Hazardous Fuels Reduction Residuals – Outside the LTB	6,500
Forest Thinning and Harvest Residuals	8,450
Tree Trimmings	17,820
Pine Needles	180
Clean Construction and Demolition Wood	63,460
TOTAL	**112,440**

Exhibit 3-2 Summary of Biomass Material Generated within the LTR Fuel Study Area

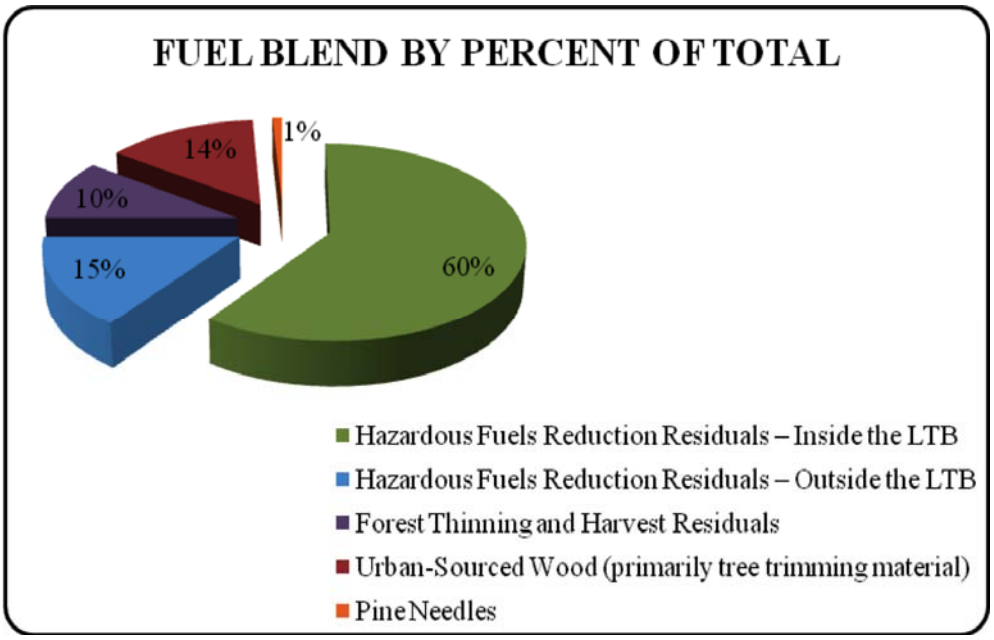

Exhibit 3-2 Practically Available Fuel Type by Percent of Total

Assuming that the LTR bio-energy project is scaled at 2 MW of electrical output and utilizes 20,000 BDT of biomass fuel (or less) annually, and then a 3.1:1 fuel cover ratio

exists. Fuel coverage ratio represents the net availability of fuel relative to new demand (the proposed LTR project) in the marketplace. The higher the fuel coverage ratio, the more fuel is forecast to be available. Private financial markets and project developers prefer a fuel coverage ratio of 2:1 or more.

This fuel assessment confirmed that the proposed facility (scaled at two MW) could be sustainably supplied with biomass fuel sourced from within a 30-mile radius of Kings Beach or Cabin Creek. With a 30-mile radius fuel-sourcing area, 100% of the fuel could be provided by fuels treatment activities within the LTB or LTR (storage issues are discussed in the Task 3 Logistics Report). Most of this forest material would not be available economically to other markets or biomass power plants, as transport costs are very significant and Placer County is working with land management agencies to cost share the collection, processing and transport expenses for biomass material that is currently open pile burned or masticated (chipped and scattered).

An optimized fuel blend for this facility assumes that 75% of the facility's fuel usage will be sourced from hazardous fuels treatment activities, with the balance being made up of forest thinning residuals and urban-sourced (primarily tree trimmings and pine needles) wood. While urban-sourced wood represents the most cost effective fuel, utilizing large volumes of urban wood fuel would defeat the primary objective of the proposed project – which is to provide a ready, sustainable market for biomass fuel generated as a byproduct of hazardous fuels reduction activities.

4.0 Quantification of Avoided Air Emissions

The bottom half of Tables 2-2, 2-3, and 2-4 (see Section 2.2 above) summarize air emissions from the three power technologies described in Section 2.1 that are avoided as a result of utilization of biomass in the proposed LTR facility operations:

- In-forest, open pile burning of biomass, the economic alternative performed in absence of a proposed facility operations for the majority of the bio-energy site operation. Without the LTR facility, this waste biomass would be open pile burned because it is too expensive to chip and transport this material to the nearest alternative use. Note that the two nearest biomass facilities to the Tahoe Region in Loyalton or Carson City, have both shut down. The current nearest biomass facility is over 90 miles away in Lincoln, CA.
- Power generation from the existing grid (including 100% fossil fuels) that is displaced by the proposed bio-energy operations.
- Reduction in size and intensity of forest fires resulting from forest fuel treatment thinning operations supported by the proposed facility biomass operations. Note that this work is currently in process, the results are not available at the time of this report.

Emissions reductions resulting from the proposed bio-energy project are significant. PM10 is reduced by over 95%, NOx is reduced by 60-90%, and VOC and CO is reduced by over 95%.

Significant amounts of excess waste biomass will be generated from the numerous future planned forest fuel treatments within the LTR area. Much of the waste woody biomass will be open pile burned at the site of generation, based on current economics and forest safety considerations. Alternative utilization of the waste biomass for energy at the proposed facility would produce significant overall reduction to the criteria air pollutant, GHG, and air toxics emissions loading to the LTR. These emission reductions should be appropriately considered when evaluating any offsets required under TRPA or PCAPCD rules and regulations.

Further, although not an economically realistic option for the waste biomass that will be processed in the proposed Tahoe Regional Facility, Table 4-1 compares the significant emissions benefits that would come from a Tahoe Regional Facility compared with waste biomass use in the closest existing biomass facility in Lincoln. These benefits come from both the significantly increased transport distance to Lincoln and higher emissions from the Lincoln plant.

Table 4-1. Comparison of Air Emissions Impact of
Tahoe Regional Facility Compared with SPI Lincoln

	NOx	PM10	NMOC	CO	CO2
	lb/MW-hr electricity				
Tahoe Regional Facility					
Biomass Plant (Phoenix)	0.31	0.144	0.312	1.6	3128
Transportation	0.17	0.004	0.005	0.4	22
TOTAL	0.48	0.148	0.317	2.0	3150
SPI Lincoln					
Biomass Plant	3.55	0.489	0.142	13.3	5210
Transportation	1.67	0.039	0.049	3.9	218
TOTAL	5.22	0.528	0.191	17.2	5428
% Reduction	**90.8%**	**72.0%**	**-65.9%**	**88.4%**	**42.0%**

Emissions factors, and other assumptions, that have been used for the emissions analyses of this section are provided in Appendix C.

5.0 Quantification of Rate of Carbon Sequestration

Numerous on-going research efforts are quantifying the GHG lifecycle impact of forest fuel treatments – including work conducted by the U.S. Forest Service Pacific Southwest Research Station and Placer County Air Pollution Control District, both integral members of this project. Forest fuel treatments remove excess hazardous fuels to reduce the potential for catastrophic wildfire -- which has significant negative environmental, economic, and social impacts. Fuel treatments involve the strategic removal of small diameter trees, small lower ladder fuels, and surface fuels, and prescribed fire, to (1) reduce the size and intensity of wildfire, and (2) aid in the growth of large diameter trees that are stable and resistant to fire, disease, and insect attack. There are numerous impacts that must be considered

- Reduction in wildfire size and intensity, with accompanying reduction in carbon lost through wildfire.
- Diesel fuel used for equipment engines for conducting fuel treatments (e.g., chain saws, loaders, and fellers).
- Diesel fuel used for engines for biomass for energy activities (biomass grinding and chip van transport).
- Displaced fossil fuel combustion resulting from biomass activities.
- Diesel fuel used for engines for wood products.
- Sequestered carbon in wood products.
- Increased forest growth rate (sequestration rate), resulting from improved growing conditions (space and light).

An example preliminary accounting for a fuel treatment project on Sierra Nevada forested land is shown in Table 5-1.

Table 5-1 GHG impacts of Forest Fuel Treatment Projects

Project Activity	CO2 Impact (1000 tons CO2e)	
	Baseline	Fuel Treatment Project
Change in Forest Carbon	74.3	188.6
Wildfire	-109.6	-67.9
Fuel Treatment		
Engines		-0.4
Removal		-163.4
Prescribed Burn		-32.7
Biomass Energy		
Engines		-4.0
Displaced Fossil Fuel		40.1
Wood Products		
Engines		-0.2
Stored Wood Product		9.8
TOTAL	-35.3	-30.1

Assumptions:	
Fireshed	10000 acres
Baseline Carbon in Forest	300 tons C/ha
Wildfire Base Emission Coefficient	0.4
Wildfire Rx Emission Coefficient	0.1
Wildfire Shadow Emission Coefficient	0.15
Wildfire Shadow Area Coefficient	1.5
Wildfire Risk	0.0041
Rx Area	2200 acres
Rx Removal	50 tons C/ha
Biomass Energy	45 tons C/ha
Wood Products	5 tons C/ha
Rx Prescribed Burn	10 tons C/ha
Life of Rx Fuel Treatment Project	15 years
Engines for Fuel Treatment	0.2 tons CO2/ac treated
Engines for Biomass Energy	0.05 tons CO2/BDT biomass
Forest Growth Baseline	5 tons C/ha
Forest Growth Rx Fuel Treatment Project	40 tons C/ha
Wood Products Stored	0.6
Engines Used for Wood Products	0.025 tons CO2/BDT
Biomass Energy Production Rate	1 MWh/BDT
Fossil Fuel Energy Displacement	0.5 ton CO2 displaced/MWh
Carbon Content of Biomass	2 BDT/ton C

It is projected that under the baseline condition (no fuel treatment) there will be a loss of carbon through both wildfire and pile burning. With the fuel treatment there will be a smaller loss of carbon and more stable forest. These numbers will change as wildfire and forest growth models are refined.

As concluded in Section 4.0 and 5.0 of this report, the proposed Lake Tahoe Region bio-energy operation will have a beyond-carbon neutral benefit resulting from the nature of the biomass wastes materials that are used as fuel. The facility operation will utilize excess biomass waste materials from hazardous fuel treatments and defensible space clearing operations that are conducted solely for independent forest management purposes, and will occur with or without the facility operation. Biomass will not be harvested for the use as fuel – biomass will only come from wastes as a byproduct of forest management projects for wildfire mitigation that are conducted under the oversight of NEPA, CEQA, and California Forest Practices rules. Biomass wastes will be open pile burned or masticated at the site of generation if the proposed facility is not available. Thus, through displacement of fossil fuel required for equivalent energy production, and avoidance of methane emissions released during pile burning and mastication, the facility operation will actually produce reductions in GHGs compared with the baseline business as usual. The proposed biomass facility operation is in stark contrast to recent studies in by the Mahomet Group in Massachusetts that have received attention for concluding that for GHGs, coal is preferable to biomass. This is because the Mahomet study was based on the use of biomass that is harvested solely for the purpose of fuel value.

6.0 Determination of GHG Offset Credits

Under AB32, the State of California has committed to reduce greenhouse gas (GHG) emissions. As part of this, the State is in the process of various activities related to reducing GHG emissions from forest management and biomass utilization: (1) development of a GHG cap and trade system for electricity generators; (2) procedures to ensure that State forests are maintained as a net carbon sequestration asset; and (3) a renewable energy standard that will encourage and accelerate the development of renewable energy. In addition, recent state legislation SB2X raised the requirement for California utilities and their Renewable Portfolio Standards from 20% renewable energy to 33% renewable energy by 2020. The local Lake Tahoe area utility, CALPECO (a.k.a Liberty Energy) , will need to meet this new requirement.

At the same time at the local level, PCAPCD is developing a procedure for generating emission offsets from biomass waste energy conversion projects, such as the Tahoe Region facility. It is planned to issue these offsets for direct mitigation for local projects, which require emission reductions based on CEQA compliance obligations; and eventually within a statewide program.

6.1. Bio-energy Project GHG Offset Protocol

A bio-energy project GHG offset protocol document was developed by our team. The protocol is intended to support projects, which produce GHG benefits through the use biomass waste for energy as opposed to disposal through open pile burning or on-site mastication. The protocol contains a detailed accounting procedure used to ensure offsets are:

- Real - Bio-energy projects must be determined to be “additional” and beyond that of “business as usual” – requiring demonstration that biomass wastes would have been pile burned without the GHG offset project support.
- Enforceable - Conditions are placed on the reductions, such as a binding and an auditable contract, or other enforceable methods employed to verify the emissions are being reduced.
- Quantifiable - Project monitoring procedures are used to accurately measure emission reductions.
- Surplus - Bio-energy projects are not required by federal, state, or local law.
- Permanent - Bio-energy project emission reductions are permanent and not reversible.

In addition, protocol eligibility requires that all bio-energy projects utilize only biomass wastes that come from harvesting that has undergone all necessary environmental assessments such as those for the National Environmental Policy Act (NEPA), California Environmental Quality Act (CEQA), California Forest Practices Rules and Regulations, Timber Harvest Plans, and/or Best Management Practices assessments.

The offset protocol has undergone thorough peer review with groups and individuals involved in the forestry, power generation, electrical utility, local regulatory agencies, California state level environmental regulators, and federal agencies. In October 2009, the protocol and planned pathway for offset management was presented to the California Board of Forestry (BOF). The BOF passed a resolution supporting the initiative and protocol. Currently, the protocol is undergoing further review by the California Air Resources Board and California Air Pollution Control Officers Association. A copy of the biomass waste for energy project accounting protocol is in Appendix C.

6.2. Local Program Implementation of Bio-energy Project GHG Offset Protocol

A local offset program will implement the bio-energy offset protocol. The program is being designed to eliminate conflict with other accounting protocols, fraudulent transactions, risk of reversal or leakage to both the offset purchaser and seller, and minimize administrative requirements and transaction costs. Exhibit 6-1 illustrates offset program implementation.

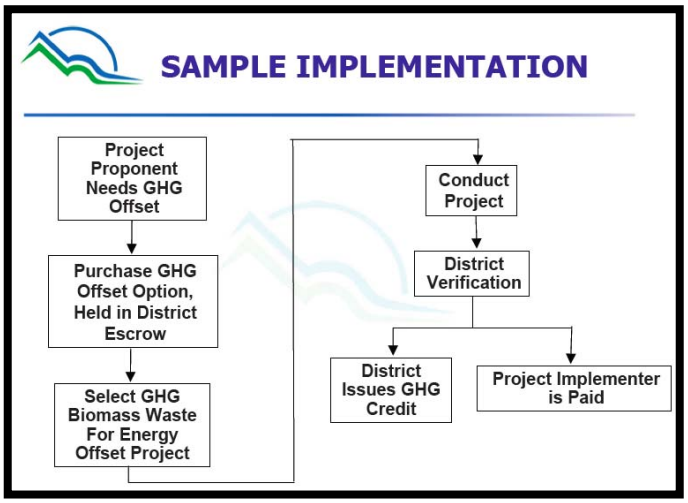

Exhibit 6-1 Sample Implementation of GHG Emission Offset Protocol Transaction

Table 6-1 described the implementation steps of the Protocol.

Table 6-1 Steps for GHG Emission Offsets Protocol Implementation

Step 1: Project Proponent Needs Emission Offset: The project proponent (an individual or organization) needs emission offsets. They contribute monetary funds to support a bio-energy project in exchange for ownership of the GHG benefits that result from the project. The funds are distributed to the project implementers to facilitate the collection, processing, and transport of biomass material that would not otherwise be disposed through a power plant or landfill.
Step 2: Purchase Emission Offset Option, Held in Escrow: The project proponent provides monetary funds to an escrow account managed by the program administrator. An emission offset credit option is placed in escrow, which will be transferred to the project proponent upon completion of the 5th step.
Step 3: Select Bio-energy Offset Project: The program administrator will maintain a list of contractors and managers that have pre-certified their projects as valid bio-energy offset projects. Project proponents will select projects from this list of pre-certified projects, or they alternatively they may select alternative projects subject to approval by the program administrator. Project proponent and implementer enter into a contractual agreement that is facilitated by the program administrator.
Step 4: Conduct project: Project is implemented, monitored, and data is submitted to the administrator for verification. The administrator will track all on-going projects for verification purposes.
Step 5: Verification: The administrator verifies that all project activities under the scope of the accounting protocol are recorded accurately and calculations are correct. The administrator utilizes the verification protocol that is currently being drafted for this offset program.
Step 6: Issuance of Emission Credit and Project Implementer is Paid: The administrator releases the credit option from the escrow account as an offset credit to the project proponent and releases funds from the escrow account to the project implementer.

On-going work to implement the program include developing a project verification protocol and contractual agreements for implementers and proponents.

6.3. Applicability to the LTR Bio-energy Facility

The biomass energy GHG emissions offset protocol would be directly applicable to the Tahoe Region energy conversion facility for biomass waste materials that are used for energy conversion that would have otherwise, under baseline business as usual conditions, been disposed of through open pile burning. The protocol requires that the following information be determined:

- Economic evaluation of all realistic biomass utilization or disposal options.
- Quantification (measurement and logging) the amount of diesel fuel used in biomass waste processing and transport operations.
- Quantification of the amount of biomass wastes that are used for electricity production and that would have otherwise been open pile burned.
- Quantification of the bio-energy waste fuel heating value.
- Quantification of the electricity producing utilizing the bio-energy, including the portion of electricity that might be claimed as "renewable energy credits" and/or used for compliance with renewable energy portfolio standards.
- Documentation of environmental assessments required as part of the bio-energy generating activities, such as those for the National Environmental Policy Act (NEPA), California Environmental Quality Act (CEQA), California Forest Practices Rules and Regulations, Timber Harvest Plans, and Best Management Practices assessments.
- Evaluation to confirm that bio-energy wastes are generated from "sustainable" harvesting operations.

Each individual bio-energy energy emission offset project will need to be arranged to delineate the "owner" of the offset credits, assignment of the appropriate verifiers, and registry and tracking of the offset credits.

7.0 Establishing a GHG Emission Offset Credit Trading Market Program

The PCAPCD project team is developing a local offset credit trading market from emissions reductions generated from bio-energy projects under the protocol described above in Section 6.0.

7.1. Local GHG Offset Credit Trading Market

The program would involve voluntary participation of the exchange of GHG emission offset credits. Issues being considered to create an effective local market include:

- Need for sufficient bio-energy projects to supply credits -- Based on work conducted by Placer County, local agencies, CALFIRE, USFS, and other agencies and organizations, there are significant quantities of bio-energy residual material generated each year as a byproduct of forest health, forest thinning, and defensible space clearing projects where otherwise biomass wastes are being disposed through open pile burning.
- Willing project proponents – The PCAPCD team is in current discussion with a California oil exploration project that is in need of offsets to meet CEQA obligations. They are interested in supporting bio-energy projects through our protocol and implementation program. A letter of interest is included at the end of this report.
- Market credibility -- The PCAPCD team is working to ensure that the offset credit trading program components -- including calculations, verification, reporting -- are completed accurately and with strict and thorough oversight. Additionally, we are working to obtain recognition of the protocol calculation and measurement methodology by a diverse set of peer, stakeholder, and regulatory groups. Discussions and vetting of the technical material is essential for market credibility of offset credits.
- Market pricing -- Credits will be charged at the marginal cost of conducting the bio-energy project and transaction. That is to say, funds will go directly into financing bio-energy projects, where the cost of the offset credits will be a direct function of project conditions, operating efficiency, and local bio-energy market conditions. Offset credit costs will be variable depending on the project situation

7.2. Participation in GHG Offset Market by the LTR Bio-energy Project

To participate in the offset credit market, the LTR bio-energy facility must identify candidate bio-energy waste streams that are planned for sustainable harvest, and are under current conditions being disposed of through open pile burning. Next, it must either: (1) locate project partners who need emissions reduction credits – such as land developers or new or expanding emissions sources, or potentially speculators who desire to own, and later sell, reduction credits – and utilize their monetary investment to run the bio-energy project; or (2) subsidize the bio-energy waste delivery and assume direct ownership of the credits for later speculative sale. Participation would involve on-going coordination with project verifiers, bio-energy waste generators, credit bank administration, and credit purchasers.

The PCAPCD team has an identified potential client for this market. The letter of Interest is attached as Appendix D.

8.0 Water Availability and Discharge

The need for water supply and discharge of a proposed bio-energy facility at Cabin Creek or Kings Beach is driven by the technology to be employed at the site. Of the various technologies examined, the direct combustion steam cycle system would potentially use the most water and would have potential wastewater discharge. Such discharge would probably necessitate pretreatment prior to discharge to the sanitary sewer.

The direct combustion steam cycle system currently used as the example of such a system would have water supply need (principally as make up water for the water cooling system) of 5 to 8 gallons per minute (gpm) per MW. This amount of water appears available and supplied by the North Tahoe Public Utility District to the Kings Beach site. At the Cabin Creek site, there is currently a 100 gpm water well supplying the ERL facility. It may be possible to get the 5 to 8 gpm from this supply, or possibly a supplementary well be have to be drilled.

The other candidate technology, gasification with electrical generation via internal combustion engines, has a much less water consumption need. The Nexterra technology reportedly has no cooling water needs at all. The Phoenix gasification technology does cool the syngas produced through a small water-cooling system. Make-up water is needed for this syngas cooling with an amount of 500 gallons (or less) per day.

Given the size of the current water supply line to the proposed Kings Beach site, additional up scaling of the size of the proposed bio-energy plant to 2 or 3 MW appears to have adequate water supply potential. An adequate water supply is certainly possible for the Cabin Creek site as well.

Regarding the discharge of water from the proposed bio-energy facility at Kings Beach, and Cabin Creek sites, again the direct combustion steam cycle system would have the highest discharge potential. Approximately 2 to 3 gpm could be discharged from such a system. As there is municipal sewer system service to both the proposed Kings Beach and Cabin Creek sites (supplied by the Truckee/Tahoe Sanitation Agency), discussion with agency representatives indicate that 2 to 3 gpm would not be problematic, but pretreatment would probably be required. The agency has a list of pollutants and their thresholds that any discharge must meet prior to discharge to the sewer system (Appendix B).

The gasification technologies do not have discharge of any cooling (or process) water. As mentioned above, Nexterra does not use any process water. Phoenix

recycles the water until only solids remains. This material is not discharged to the sewer system, but instead is removed as a solid waste and transported to an appropriately permitted off-site disposal facility or as it primarily tars from the gasification process, it could be recycled back into the gasification process.

APPENDIX A – DISCHARGE WATER LIMITS

TAHOE-TRUCKEE SANITATION AGENCY
A Public Agency
13720 Joerger Drive
TRUCKEE, CALIFORNIA 96161
(530 587-2525 • FAX (530) 587-5840

Directors
O.R. Butterfield
Dale Cox
Erik Henrikson
S. Lane Lewis
Jon Northrop
General Manager
Marcia A. Beals

PRELIMINARY DISCHARGE GUIDELINES
Local Discharge Limits (a)

CONSTITUENT	MILLIGRAMS/LITER
Arsenic	1.0
Cadmium	1.0
Chromium (Total)	2.0
Copper	3.0
Cyanide (Amenable)	1.0
Cyanide (Total)	5.0
Iron	25.0
Lead	2.0
Manganese	1.1
Mercury	0.03
Nickel	10.0
Oil and Grease of Animal or Vegetable Origin	100.0
Oil and Grease of Petroleum Origin	20.0
Pesticides	0.01
Polychlorinated Biphenyls	0.01
Silver	0.05
Sulfide (Dissolved)	0.5
Sulfide (Total)	5.0
Suspended Solids	20.0
Total Petroleum Hydrocarbon (TPH)	1.0
Total Toxic Organics	0.58
Zinc	10.0
Sulfate	150
Total Dissolved Solids	1,000
Aluminum	22.0
pH 6.5 to 8.5	
	PARTS PER BILLION
Acetone (di methyl ketone)	700
Benzene	5
Carbon Tetrachloride	5
Ethylbenzene	680
MTBE	13
Styrene	100
Tert Butyl Alcohol	100
Tetrachloroethene (PCE)	5
Toluene	100
Vinyl Chloride	2
Xylene	620

LIMITS FOR WASTEHAULERS DISCHARGING DOMESTIC WASTE

CONSTITUENT	MILLIGRAMS/LITER
Cadmium	1.0
Chromium	2.0
Copper	25.0
Lead	10.0
Zinc	50.0

(a) Users subject to Federal Categorical Pretreatment Standards may be required to meet more stringent limits.

6/8/2009

APPENDIX B – RELEVANT AIR, WATER, AND GHG REGULATIONS AND GUIDELINES

- TRPA
- Lahonton RWQCB
- Placer County
- State of CA
- Federal

THIS APPENDIX WILL BE FILLED IN WITH REGULATORY INFORMATION TO BE PRESENTED IN THE FORTHCOMING ENVIRONMENTAL IMPACT REPORT

Appendix C – Emission Analysis Assumptions

Data Used for Emission Calculations

Emission Factors						
Process	Units	NOx	PM10	NMOC	CO	CO2
Open Pile Burning	lb/dry ton wood	6	15	10	125	3667
Chip Van Engine	g/mile	17	0.4	0.5	40	2222
Chip Van	g/mile unpaved road		2.1			
Grinder Engine Tier III	lb/wet ton wood	0.072	0.003	0.004	0.093	13.7
SPI Loyalton/Lincoln Boiler	lb/dry ton wood	2.5	0.344	0.1	9.36	3667
California Electricity Grid	kg/MWh	0.03	0.018	0.0018	0.03	390
Miscellaneous Factors						
Other factors	Units					
Open Pile Burning Efficiency	tons wood burned/dry ton	0.95				
Chip Van Engine Mileage	miles/gal	4.5				
Diesel CO2 Emissions	kg CO2/gal diesel	10				
Grinder Efficiency	gal diesel/wet ton wood	0.62		700 HP, 50 green ton/hr		
Other						
Wood Heating Value	Btu/dry lb	8000				
Electricity Production Efficiency						
Envio	%	0.16				
Nexterra	%	0.32				
Phoenix	%	0.24				
Phoenix Emissions	lb/dry ton wood	0.4	0.2	0.4	1.9	3667
Transportation (40 miles)	lb/dry ton wood	0.2	0.0046	0.0057	0.5	25.5

Data sources:

Bruce Springsteen, Tom Christofk, Steve Eubanks, Tad Mason, Chris Clavin, and Brett Storey, Emission reductions from woody biomass waste for energy as an alternative to open pile burning, Journal of the Air and Waste Management Association, Volume 61, pages 63-68, January 2011.

Technical literature and discussions from Envio, Nexterra, and Phoenix Energy biomass energy conversion system vendors.

Appendix D – Letter Of Interest

SANTA MARIA PACIFIC

July 25, 2011

VIA ELECTRONIC EMAIL
Thomas Christofk, APCO
Placer County Air Pollution Control District
110 Maple Street
Auburn, CA 95603

Dear Tom:

We are writing in support of Placer County Air Pollution Control District's ("District") Biomass for Energy GHG Offset program and to confirm our interest in working together to create the first public-private partnership aimed at creating a viable and beneficial market for GHG emissions offsets.

As we discussed, Santa Maria Pacific, LLC ("SMP") is an independent energy company committed to the responsible exploration and development of oil and gas resources in Santa Barbara County, California. SMP is currently seeking approval of an Oil Drilling Production Plan for a project in the State Designated Orcutt Oil Field (the "ODPP") located in Santa Barbara County. The ODPP includes a total of 136 production wells, three steam generators and related facilities. SMP is committed to developing the project in a manner that reduces GHG impacts to the maximum extent possible. By design, the project will include many onsite design elements that mitigate overall GHG emissions, including proximity to the California oil and gas market which offers inherent GHG benefits over foreign oil extraction projects. The project will also fully comply (to the extent applicable) with Assembly Bill 32, the landmark law designed to specifically address California GHG emissions. In addition, SMP is seeking other on- and off-site measures that will further mitigate the project's emissions.

The District has developed a carbon offset biomass program that is already successfully facilitating the conversion of forest waste into renewable energy within the Sierra Nevada of California. SMP recognizes that this program is carefully crafted to calculate carbon emissions through sound scientific and mathematical principles and can provide the credits required by permitting agencies. The program will make available offset credits for purchase by SMP that will finance "biomass waste for energy" projects within California.

SMP and the District will work together to ensure that issues relating to the differences between biogenic and geologic carbon are vetted, and will also work with the District to ensure that all aspects of the biomass program are focused on sound forest health and wild fire protection. SMP and the District are committed to implement greenhouse gas mitigation projects that are consistent with sound forest management activities and compliant with the California Forest Practices Act, CEQA, and NEPA. The California Board of Forestry has endorsed the District's Biomass for Energy GHG mitigation protocol because it furthers their mission in support of healthy and fire resilient forest landscapes in California.

SMP has already begun initial discussions with local agencies and has received support from the agencies in concept. By purchasing credits through the District's biomass program, SMP will enable the District to engage in collection and utilization of forest biomass (normally open burned) that would have not occurred but for SMP's participation in the program. SMP's participation in the program will provide real, permanent, verifiable, and quantifiable GHG offsets. It is expected the credits will support SMP's project compliance with CEQA and also meet its obligations under AB 32 and the California's Cap and Trade program, as well as meet its requirements under the Clean Air Act.

SMP supports the California-based "biomass waste for energy" program initiative because it offers a local solution to a global problem. As a California company, SMP can offset its impacts within California while supporting a variety of ecosystem service co-benefits beyond just greenhouse gases. Such benefits could include a reduction in criteria of air pollution, improved wildlife habitat, enhanced water quantity and quality, improved forest eco-system health, and reduction in catastrophic wildfire risks and hazards. SMP's operations already offer significant GHG benefits over oil and gas operations sited in less environmentally regulated parts of the world. They also help curb the ongoing decrease in California oil production, which in turn helps reduce California's dependence on more GHG-intensive foreign oil imports and the emissions generated from importing oil to the U.S. By participating in a partnership with the District, SMP will be able to fully mitigate its carbon footprint within California.

SMP looks forward to continuing to work with the District on what it hopes will be a beneficial public/private partnership that can serve as a model for others nationwide.

Very truly yours,

Beth A. Marino
VP – Legal & Corporate Compliance

BAM/je

cc: David L. Pratt, President, Santa Maria Pacific, LLC
Bob Poole, Public & Governmental Affairs Manager, Santa Maria Pacific, LLC

P.O.BOX 7202 • SANTA MARIA CA • 93456-7202
PHONE: 805.938.3320 • FAX: 805.938.3340

Appendix E – Bio-energy for Energy Project Reporting Protocol

Biomass Waste for Energy Project Reporting Protocol

GHG Emission Reduction Accounting

Version 4.0

June 2011

Placer County Biomass Utilization Pilot Project, Phase I
Air/Water Emissions and Carbon Credits/Emissions Offsets
November 2011

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1. Introduction

This protocol provides accounting, reporting, and monitoring procedures to determine greenhouse gas (GHG) reductions associated with biomass waste for energy projects.

The protocol is for projects which process and transport biomass waste for the generation of energy (e.g. electricity and process heat). The protocol is limited to projects where, under baseline, business as usual conditions, at the start of the project, the biomass waste would have otherwise been disposed of through: (1) open burning, (2) decay and decomposition in the field; or (3) landfill. The protocol is also limited to biomass waste that is the result of sustainable harvesting operations or urban biomass waste generation.

Biomass waste for energy projects reduce GHG emissions through: (1) avoiding methane (CH_4) and nitrous oxide (N_2O) emissions that occur during disposal through open burning, decay and decomposition, and/or landfilling; and (2) producing renewable energy that displaces GHG emissions from fossil fuel combustion needed for an equivalent energy supply.

2. GHG Reduction Project – Biomass Waste for Energy

Biomass waste is generated from forestry, agriculture, urban landscape, and related industries. Biomass is defined as non-fossilized and biodegradable organic material originating from plant material. Biomass waste is disposed of through open burning, decay and decomposition in the field, or landfill. Biomass includes:

- Forest slash / non-merchantable remains from forest management activities including timber harvesting or forest thinning. These include small trees, brush, tree tops, and branches.
- Defensible space clearing residues (brush, tree branches and trunks, clippings).
- Orchard and vineyard removals and prunings.
- Field straws and stalks.
- Urban prunings/cuttings residues

Biomass waste has energy content that can be utilized in energy recovery facilities, which include:

- Direct biomass combustion, producing heat and/or electricity.

- Biomass gasification, producing syngas used for heat or electricity production, or conversion into alternative transportation fuels (e.g. biofuels).

Sources of GHG emissions from a biomass waste for energy project are shown in Table 2.

2.1. Project Definition

For this protocol, the GHG reduction project involves the use of biomass for energy recovery, where otherwise under baseline, business as usual conditions, the biomass would have been disposed of through open burning, left to decay and decompose in the field, or landfilled.

The project developer must provide information defining the project operations, including:

- Location where the biomass is generated.
- Operation for which the biomass is a byproduct, i.e. how is the biomass generated.
- Generation (rate and timing) of the biomass.
- Composition of the biomass.
- Historical, current, and anticipated future, disposal practice for the biomass in the absence of the proposed biomass to energy project.
- Biomass processing operations prior to transport, such as conveyors, grinders, and loaders.
- Biomass transportation method.
- Location of energy recovery facility.

- Type of energy produced (e.g. electricity, heat, fuels).
- Estimated cost of processing and transporting biomass to the energy recovery facility.
- Generation rate of energy from biomass.
- User(s) / purchaser(s) of energy generated from biomass.
- Permitting status of the energy recovery facility.
- Documentation of environmental assessments required as part of the biomass generating activities, such as those for the National Environmental Policy Act (NEPA), California Environmental Quality Act (CEQA), California Forest Practices Rules and Regulations, Timber Harvest Plans, and Best Management Practices assessments.

This information must be provided in Form A, included as an attachment to the protocol.

2.2. Project Developer

Project developers can include biomass generators, biomass waste energy recovery operators, and/or third party aggregators. Ownership of the GHG reductions must be established by clear and explicit title, where ownership is determined through agreement between project developers. This is important to avoid double counting of reductions by the energy recovery operator, biomass processor, biomass owner (landowner), or third party investor.

2.3. Methane and Nitrous Oxide Global Warming Potential Characterization Factors

Methane (CH_4) has a global warming potential characterization factor of 21 tons of CO_{2e} per ton of methane.

Nitrous oxide (N_2O) has a global warming potential characterization factor of 310 tons CO_{2e} per ton N_2O.

3. Eligibility

Projects must meet the following requirements to be eligible for GHG offset credits under this protocol.

3.1. Biomass from Qualified Operations

The biomass waste material used for energy recovery must be characterized as:

- "Biomass" – The material must be non-fossilized and biodegradable organic material.
- "Excess waste" – The material must be an excess waste byproduct that, in the absence of the project, would be disposed of through open burning, or deposited in the field.
- "Sustainable" – The material must be a byproduct of operations which:
  - -- Protect or enhance long-term productivity of the site by maintaining or improving soil productivity, water quality, wildlife habitat, and biodiversity.
  - -- Meet all local, state, and federal environmental regulations, including National Environmental Policy Act (NEPA), California Environmental Quality Act (CEQA), California Forest Practices Rules and Regulations, Timber Harvest Plans, and Best Management Practices.

3.2. Additionality

Project GHG emission reductions must be "additional" to what would have otherwise occurred.

It must be demonstrated that the existing disposal practice of the excess biomass waste residues at the beginning date of the project is through either:

- Open burning in the vicinity of the production site.
- Decay and decomposition in the vicinity of the production site, with no commercial value derived from the end-product.
- Landfilled.

The project developer must demonstrate there are no alternative uses for the biomass waste. It must not be currently economical within the local market to sell biomass waste as a product or process feedstock. This requires providing documentation of previous historical disposal practices, current disposal practices (in the absence of the proposed project), and future planned/anticipated disposal practices.

3.3. Energy Recovery

The biomass must be used in an energy recovery facility. The energy recovery facility must:

- Meet all Federal, State, and local environmental regulations, including (but not limited to) air quality, water discharge, and solid waste.
- Produce energy (e.g. electricity, heat, fuel) that is under direct control of, the project developer or under the direct control of an entity that has a contractual agreement with the project developer (or an affiliate of the project developer) to produce energy.
- Produce energy that is valuable and utilized, and would not have otherwise been generated.

3.4 Energy Sales

Energy produced from the biomass waste project must not be claimed as renewable energy credits that are used for compliance with GHG renewable energy or portfolio standards.

If the energy sector for which the biomass waste energy is produced is under a GHG cap and trade regulation, GHG allowances, such as renewable energy "set-aside" allowances, must be obtained for the GHG offsets that are claimed under this accounting offset protocol.

3.5 Location

This protocol is applicable to biomass recovery project operations that are located in the United States.

3.6 Project Start Date

Projects are eligible which begin after the date of approval of the protocol, and after the necessary project initiation forms have been completed and approved.

4 GHG Assessment Boundary

The biomass waste for energy project boundary is defined to include all GHG emissions from operations that are the result of the biomass for energy project. The physical boundary of the biomass waste for energy project is shown in

Figure 1. GHG emissions must be accounted for operations, as detailed in Table 2, including:

Baseline, Business as Usual

- Open biomass burning. Includes quantification of CO_2, CH_4, and N_2O.
- Decay and decomposition of biomass disposal in field. Includes quantification of CH_4 and N_2O.
- Landfill. Includes quantification of CH_4.

Biomass Waste for Energy Project

- Fossil fuel fired engines, at the site where the biomass is generated, that would not have been used had the biomass been disposed of through open burning or left to decay. This includes engines that power biomass processing equipment used at the site of waste generation – including chippers, grinders, shredders, loaders, excavators, conveyors, etc. Includes quantification of CO_2.
- Fossil fuel fired engines used to facilitate transport of excess biomass waste from the site of generation to the energy recovery facility. Includes quantification of CO_2.
- Biomass usage at the energy recovery facility. For biomass combustion boilers, quantification of CO_2 is required. The quantification of CH_4 and N_2O is not required as it is considered negligible for a combustor that meets state and local air quality regulations. Other types of energy recovery units may require quantification of CH_4 and N_2O.
- Fossil fuel fired engines, at the energy recovery site, that are associated with the biomass usage that would not have been used otherwise used in the absence of the project. Includes quantification of CO_2 emissions.
- Fossil fuel fired engines used for transportation of equipment and personal to the excess biomass processing site. Includes quantification of CO_2 emissions.
- Fossil fuel fired engines used at biomass waste for energy facility for operation of auxiliary equipment, such as conveyors and loaders. Includes quantification of CO_2 emissions.

5 GHG Reduction Calculation Methods

5.4 Biomass Waste for Energy Project

5.4.1 Biomass Processing Rate

Determine the quantity of biomass (total wet weight), BM_W , meeting the above eligibility criteria, which is delivered to the energy recovery facility:

$BM_{T, W}$ Quantity of wet (green) biomass utilized at energy recovery facility (wet tons). Determined from the summation of direct weight measurement of every separate biomass delivery received at the energy recovery facility.

Determine the quantity of biomass (total bone dry weight), $BM_{T, D}$, as.

$$BM_{T, D} = BM_{T, W} * (1 – M) \quad \text{(Eq. 1)}$$

where:

M Moisture content of biomass (%). Determined through sampling and analysis of the biomass delivered to the energy recovery facility. (Sampling and measurement will be based on ASTM E870-82, ASTM D 3173, or equivalent. Sampling will occur at biomass energy recovery facility.)

5.4.2 Energy Produced from Biomass

Determine the energy content of biomass delivered to the biomass energy recovery facility, Q_{BM}, (MMBtu) as:

$$Q_{BM} = BM_{T, D} * HHV_{BM} \quad \text{(Eq. 2)}$$

where:

HHV_{BM} Higher Heating Value of biomass waste (MMBtu/dry ton). Determined by periodic or most current sampling and analysis of biomass. (Measurement of HHV will be based on ASTM E870-82, ASTM D 5865, or equivalent.). HHV is utilized within this protocol instead of LHV because it is more prominently used in the biomass energy recovery industry. If LHV is utilized, appropriate conversion factors must be used to calculate an equivalent HHV.

Next, determine the energy produced from the biomass at the energy recovery facility, E_{BM}, as:

$E_{BM} = Q_{BM} * f$ (Eq. 3)

where:

f Energy production generation efficiency. Determined as the ratio of net useful energy produced by the facility (gross energy produced minus parasitic plant energy requirements) to the total fuel heat input rate. This parameter must be determined on a basis of HHV.

For the production of electricity, this is referred to as the facility heat rate (determined as the kWh_e new electricity / MMBtu fuel input).

The efficiency will be based on measurements of facility operations using the biomass waste based on an annual facility average efficiency.

5.4.3 GHG Displaced by Energy Produced from Biomass

Determine the GHG emissions from fossil fuel combustion that are displaced by the energy produced from the biomass, GHG_E, as:

$GHG_E = E_{BM} * EF_E$ (Eq. 4)

where:

EF_E Emission factor for CO_{2e} from energy generation that is displaced by the biomass for energy project (tons CO_{2e} / unit of energy supplied by the excess biomass for energy facility).

It is recommended that for displaced electricity, the use of a factor of 800 lb CO_{2e} / MW – based on marginal electricity generation supplied by a combined cycle natural gas turbine plant.

5.4.4 GHG Emissions from Ancillary Biomass Handling, Processing, and Transportation Operations

Determine the amount of GHG resulting from ancillary biomass handling, processing, and transport operations, GHG_{AUX} , as:

$GHG_{AUX} = GHG_{TRANS} + GHG_{PROC}$ (Eq. 5)

where:

$GHG_{TRANS} = VM * MPG * EF_{FF}$ (Eq. 6)

GHG_{TRANS} CO_{2e} emissions from vehicles used to transport biomass to the energy recovery facility; and vehicles used to transport workers to the biomass processing site.

VM Vehicle miles driven for biomass transport (round trip); and miles driven to transport workers to the biomass processing site. In reporting period.

MPG Vehicle mileage achieved by transport vehicles (miles/gallon).

EF_{FF} Emission factor for CO_2 for fossil fuel combustion (lb CO_2 / gal fuel) -- for diesel, 22.23 lb CO_2/gallon; for gasoline, 19.37 lb CO_2/gal.

and

$$GHG_{PROC} = (T_{FF} * R_{FF}) * EF_{FF} \quad \text{(Eq. 7)}$$

where:

T_{FF} Time equipment used to operate biomass processing equipment, including grinders, chippers, shredders, conveyors, and loaders, bulldozers, and excavators. (Reported in hours).

R_{FF} Average volumetric fuel use rate (gallons per hour) for equipment used to operate biomass processing equipment, including grinders, chippers, shredders, conveyors, and loaders, bulldozers, and excavators. (Reported in hours).

5.1.4 GHG Emissions From Biomass Combustion

Determine CO_2 from biomass combustion, as:

$$GHG_{BCOM} = BM_{T,\,D} * EF_{CO2\ BM}$$

where:

$EF_{CO2\ BM}$ Emission factor for CO_2 from biomass combustion, recommended as 1.8 tons CO_2 / ton dry biomass.

5.4.5 GHG Emissions From Biomass for Energy Project

Determine the biomass for energy project GHG emissions, GHG_{PROJ}, as:

$$GHG_{PROJ} = GHG_{AUX} - GHG_{E} + GHG_{BCOM} \quad \text{(Eq. 8)}$$

5.5 ***Baseline***

5.5.1 *Baseline Biomass Disposal Practice*

Determine the quantity (dry tons) of biomass that would have been uncontrolled open burned, $BM_{OB, D}$, the quantity of biomass that would have been left to decay in the field, $BM_{DD, D}$, and the quantity of biomass that would have been landfilled, $BM_{LF, D}$:

$$BM_{OB, D} = BM_{T, D} * X_{OB} \quad \text{(Eq. 9)}$$

$$BM_{DD, D} = BM_{T, D} * X_{DD} \quad \text{(Eq. 10)}$$

$$BM_{LF, D} = BM_{T, D} * X_{LF} \quad \text{(Eq. 11)}$$

where:

X_{OB} Fraction (dry weight %) of biomass that would have been uncontrolled open burned. Based on historical, current, and future projected practices.

X_{DD} Fraction (dry weight %) of biomass that would have been left to decay in the field. Based on historical, current, and future projected practices.

X_{LF} Fraction (dry weight %) of biomass that would have been landfilled.

5.5.2 *GHG Emissions from Baseline Disposal*

Determine GHG emissions that would have resulted from the baseline disposal practices, GHG_{BASE}, as the sum of emissions from uncontrolled open burning, GHG_{OB}, field decay and decomposition, GHG_{DD} , and landfilled, GHG_{LF}, as:

$$GHG_{BASE} = GHG_{OB} + GHG_{DD} + GHG_{OB} \quad \text{(Eq. 12)}$$

where:

GHG_{BASE} Total baseline greenhouse gas emissions, as CO_2 equivalent (tons CO_{2e})

GHG_{OB} Greenhouse gas emissions from uncontrolled open burning, as CO_2 equivalent (tons CO_{2e})

GHG_{DD} Greenhouse gas emissions from field decay and decomposition, as CO_2 equivalent (tons CO_{2e})

GHG_{LF} Greenhouse gas emissions from landfilling, as CO_2 equivalent (tons CO_{2e})

and,

$$GHG_{OB} = (EF_{OB, CO2} * BM_{OB, D} * BF) + (EF_{OB, CH4} * BM_{OB, D} * BF * 21) + (EF_{OB, N2O} * BM_{OB, D} * 310) \quad \text{(Eq. 13)}$$

$$GHG_{DD} = EF_{DD, CH4} * BM_{DD} * 21 + EF_{DD, N2O} * BM_{DD} * 310 \quad \text{(Eq. 14)}$$

$$GHG_{LF} = EF_{LF, CH4} * BM_{DD} * 21 \quad \text{(Eq. 15)}$$

where:

EF_{OB} Emission factor for CO2, CH_4 and N_2O from uncontrolled open pile burning of biomass. Recommend the use of:

- CO_2 : 1.8 tons CO_2 / ton dry biomass
- CH_4 : 0.004 ton CH_4 / ton dry biomass
- N_2O : 0.00015 ton N_2O / tons dry biomass

BF Biomass burn out efficiency of the open pile burn. Recommend the use of 95%.

EF_{DD} Emission factor for CH_4 and N_2O from in-field decay and decomposition of biomass. Recommend the use of 0.05 ton CH_4 / ton dry biomass. Recommend the use of 0 tons N_2O / ton dry biomass.

EF_{LF} Emission factor for CH_4 from landfilling of biomass. Recommend the emission factor be determined using the procedure contained in the Climate Action Reserve Landfill Protocol for GHG Offset Projects.

5.6 Net GHG Project Reduction

Determine GHG reductions from biomass waste to energy recovery project, GHG_{NET}, as:

$$GHG_{NET} = GHG_{BASE} – GHG_{PROJ} \quad \text{(Eq. 14)}$$

6 Monitoring

Project data monitoring requirements are shown Form B.

7 Reporting and Recordkeeping

7.4 Project Commencement

Form A must be completed, submitted, and approved prior to project commencement, as discussed in Section 2 and 3.

7.5 Recordkeeping

Form B can be used to collect, maintain, and document the required information. Information is to be kept for a period of 10 years after it is generated, or 7 years after the last verification.

7.6 Reporting

Form C can be used to report on project emission reductions. Reporting must be made on a monthly basis.

Project developers must report GHG emission reductions on an annual (12-month) basis.

8 Glossary of Terms

Additionality: Biomass residue management practices that are above and beyond business as usual operation, exceed the baseline characterization, and are not mandated by regulation.

Biogenic CO_2 Emissions: CO_2 emissions resulting from the combustion and/or aerobic decomposition of organic matter. Biogenic emissions are considered to be a natural part of the Carbon Cycle, and are not part of the baseline or project emissions characterization/calculation.

Biomass energy recovery operator: Entity that owns and/or operates a facility that processes and utilizes biomass waste as a feedstock to generate useful energy (electricity).

Biomass generator: Landowner or independent contractor that conducts operations that result in the generation of biomass residuals.

Biomass residue: Non-fossilized and biodegradable organic material originating from plant material, which due to economic considerations are disposed of through open burning or deposited at the site of generation and left to decay and decompose or are transported to a landfill.

Carbon dioxide (CO_2): Greenhouse gas consisting of a single carbon atom and two oxygen atoms.

CO2 equivalent (CO_{2e}): The quantity of a given GHG multiplied by its total global warming potential.

Emission Factor (EF): A value for determining an amount of a greenhouse gas emitted for a given quantity of activity data (e.g. short tons of methane emitted per dry ton of biomass combusted).

Existing biomass for energy project: A project that generates biomass material that meets all qualification requirements of this protocol that diverts less than 100% of biomass waste material generated to a biomass energy recovery facility.

Flaring: Use of a combustion device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame.

Fossil fuel: A fuel, such as coal, oil, and natural gas, produced by the decomposition of ancient (fossilized) plants and animals.

Greenhouse gas (GHG): Includes carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs).

Global Warming Potential (GWP): The ratio of radiative forcing (degree to warming to the atmosphere) that would result from the emission of one unit of a given GHG compared to one unit of CO2)

kWh_e: Kilowatt-hour of electricity.

Methane (CH_4): Greenhouse gas with a GWP of 21, consisting of a single carbon atom and four hydrogen atoms.

MMBtu: Million British thermal units.

MWh_e: Megawatt-hour of electricity.

Nitrous oxide (N_2O): Greenhouse gas with a GWP of 310, consisting of two nitrogen atoms and a single oxygen atom.

Open Burning: The intentional combustion of biomass material without processing or energy recovery operations.

Project Developer(s): An entity (or multiple entities) that undertakes a project activity, as defined in the Biomass for Energy Protocol. Project developers include, but are not limited to biomass waste generators, biomass waste energy recovery operators, and/or third party aggregators.

Syngas: Synthetic gas produced through industrial processing of biomass material into gaseous (i.e. methane) or further refined into liquid fuels (biofuels).

Third Party Aggregator: An entity that facilitates the project as is not the landowner, biomass waste generator, or biomass waste energy recovery operator for the purpose of generating GHG emission offset credits.

9 References

California Air Resources Board (CARB), Greenhouse Gas Inventory, 1990-2004, Nov. 17, 2007.

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Mann, M. and P. Spath, "Life Cycle Assessment Comparisons of Electricity from Biomass, Coal, and Natural Gas," 2002 Annual Meeting of the American Institute of Chemical Engineers, National Renewable Energy Labratory, Golden, Colorado, 2002.

U.S. EPA, Compilation of Air Pollutant Emission Factors, AP-42, Section 2.5, Open Burning, October 1992.

U.S. EPA, Compilation of Air Pollutant Emission Factors, AP-42, Section 13.1, Prescribed Burning, October 1996.

U.S. EPA, "Emission Facts – Average Carbon Dioxide Emissions Resulting from Gasoline and Diesel Fuel," EPA420-F-05-001, February 2005.

10 Emission Factors

Methane Emission Factors for Open Burning of Biomass

Reference	CH4 as reported by author	CH4 lb/dry ton fuel consumed
U.S. EPA, Compilation of Air Pollutant Emission Factors, AP-42, Section 13.1, Prescribed Burning, October 1996, Table 13.1-3. (Based on data from C.C. Hardy and D.E. Ward, Emission factors for particulate matter by phase of combustion from prescribed burning, Annual Meeting of Air Pollution Control Association Pacific Northwest International Section, Eugene, OR, November 19-21, 1986; and D.V. Sandberg and R.D. Ottmar, Slash burning and fuel consumption in the douglas fir subregion, 7th Conference on Fire and Forest Meteorology, For Collins, CO, April 1983).		
Broadcast Logging Slash		
Hardwood (fire)	6.1 g/kg fuel consumed	12.2
Conifer short needle (fire)	5.6 g/kg fuel consumed	11.2
Conifer long needle (fire)	5.7 g/kg fuel consumed	11.4
Logging slash debris dozer piled conifer (fire)	1.8 g/kg fuel consumed	3.6
D.E. Ward, C.C. Hardy, D.V. Sandberg, and T.E. Reinhardt, Mitigation of prescribed fire atmospheric pollution through increased utilization or hardwoods, pile residues, and long-needled conifers, Part III, Report IAG DE-AI179-85BP18509 (PNW-85-423), USDA Forest Service, Pacific Northwest Station, 1989.		
Broadcast Burned Slash		
Douglas fir	11.0 lb/ton fuel consumed	11.0
Ponderosa pine	8.2 lb/ton fuel consumed	8.2
Mixed conifer	12.8 lb/ton fuel consumed	12.8
Pile and Burn Slash		
Tractor piled	11.4 lb/ton fuel consumed	11.4
Crane piled	21.7 lb/ton fuel consumed	21.7
U.S. EPA, Compilation of Air Pollutant Emission Factors, AP-42, Section 2.5, Open Burning, October 1992, Table 2.5-5. (Based on G. Yamate et al., 1975; L. Fritschen, et al., 1970; and D. Sandberg et al., 1975).		
Unspecified	5.7 lb/ton material burned	10.4
Hemlock, Douglas fir, cedar	1.2 lb/ton material burned	2.4
Ponderosa pine	3.3 lb/ton material burned	6.6
W. Battye and R. Battye, Development of Emissions Inventory Methods for Wildland Fire, prepared under Contract EPA No. 68-D-98-046, Work Assignment No. 5-03, February 2002. (Based on data from D.E. Ward and C.C. Hardy, Smoke emissions from wildland fires, Environment International, Vol. 17, pp. 117-134, 1991.)		
90% combustion efficiency	3.8 g/kg fuel consumed	7.6

B. Jenkins, et al., Atmospheric Pollutant Emission Factors from Open Burning of Agricultural and Forest Biomass by Wind Tunnel Simulations, CARB Report No. A932-196, April 1996.

Ponderosa pine pile burn	1.3 g/kg dry fuel	1.7
Almond pruning pile burn	1.2 g/kg dry fuel	2.6
Douglas fire pile burn	1.9 g/kg dry fuel	3.0
Walnut pruning pile burn	2.0 g/kg dry fuel	4.0

R. Kopmann, K. von Czapiewski, and J.S. Reid, A review of biomass burning emissions, part I; gaseous emission of carbon monoxide, methane, volatile organic compounds, and nitrogen containing compounds, Amos. Chem. Phys. Discuss., Vol. 5, pp. 10455-10516, 2005.

Literature search on biomass open burning	1 - 20 g/kg dry fuel	10.0

Nitrous Oxide Emission Factors for Open Burning of Biomass

Delmas, R., Lacaux, J.P., Brocard, D. "Determination of biomass burning emission factors: methods and results," Journal of Environmental Monitoring and Assessment, Vol. 38, 181-204, 1995.	0.00015 ton / ton dry

Methane Emission Factors for Decay and Decomposition of Biomass

Mann, M. K., and P. L. Spath, "Life Cycle Assessment Comparisons of Electricity from Biomass, Coal, and Natural Gas," 2002 Annual Meeting of the American Institute of Chemical Engineers. Golden, Colorado, National Renewable Energy Laboratory, 2002.	0.05 ton / ton dry
Assumes 9% carbon in biomass is converted to carbon in methane. Biomass has a molecular formula of $C_6H_{10}O_6$.	

Nitrous Oxide Emission Factors for Decay and Decomposition of Biomass

Engineering judgment. At temperatures of in-field decay and decomposition, N_2O is expected to be negligible. Nitrogen in fuel will go to NH_3.	0 ton /ton dry

11 Attachments

Table 2. Biomass for Energy Project -- Source Categories, GHG Sources, and GHG Emissions

Source	Associated GHGs	Included in GHG assessment boundary
Baseline		
Open Uncontrolled Pile Burning	CO_2	Included
	CH_4	Included
	N_2O	Included
In-field Decay and Decomposition	CO_2	Included
	CH_4	Included
	N_2O	Included
Landfill	CO_2	Included
	CH_4	Included
Biomass for Energy Project		
Transportation -- engine combustion of fossil fuels	CO_2	Included
	CH_4	Not included; negligible
	N_2O	Not included; negligible
Processing and Handling at Generation Site -- engine combustion of fossil fuels	CO_2	Included
	CH_4	Not included; negligible
	N_2O	Not included; negligible
Energy Recovery Facility	CH_4	Not included for combustors; may need to be included for other energy processing types
	CO_2	Included
	N_2O	Not included; negligible
Processing and Handling at Energy Recovery Facility – engine combustion of fossil fuels	CO_2	Included
	CH_4	Not included; negligible
	N_2O	Not included; negligible
GHGs from conventional energy production displaced by energy from biomass waste	Dependent on conventional energy source	Included

Figure 1. System Boundary Definition

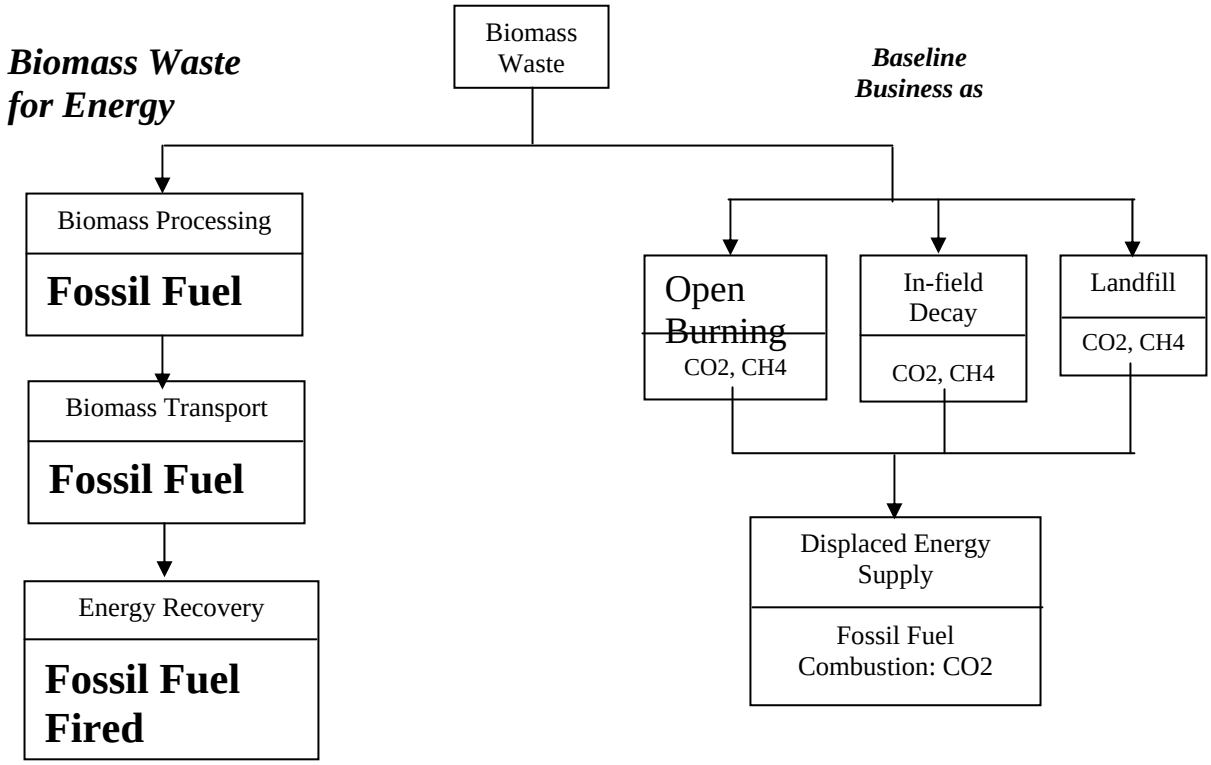

Figure 2. Example Calculation, Reporting and Monitoring forms submittal

Form A. Project Definition

Date:	
Project Title:	
Project Developer:	
Project Address:	
Permitting Status:	
Biomass Generation & Disposal Information	
Composition of Biomass (including moisture content)	
Historic, Current, and Anticipated Disposal Practice	
Biomass Generation Rate (green tons/day)	
Cost of Biomass Processing and Transport ($/green ton)	
Biomass Energy Recovery Information	
Type of Energy Produced	Electricity Heat Fuels Other
Name & Location of Energy Recovery Facility	
Generation Rate of Recovered Energy (MMBtu/day)	
Users/Purchasers of Recovered Energy	

Form B. Monitoring and Recordkeeping

Date:			
Project Title:			
Project Developer:			
Start Date of Monitoring Period:		End Date of Monitoring Period:	

Monitoring and Parameter Measurements

Parameter	Description	Data Unit	How Measured	Measurement Frequency	Reported Measurement
$BM_{T, W}$	Biomass delivered to energy recovery facility	wet tons / delivery	Transport vehicle weight scale	Every separate delivered load	
M	Moisture content of biomass	moisture, wt. %	Sampling and analysis of biomass wastes	Every separate delivered load	
HHV_{BM}	Higher heating value of biomass waste	Btu/lb, dry	Sampling and analysis of biomass wastes	Periodic – at least once per month	
f	Energy production efficiency of energy recovery facility	net useful energy / biomass heat input	Measurement of boiler output and waste fuel input. Alternatively, based on manufacturer design specifications	Start of program; and updated as needed	
VM	Vehicle miles traveled for biomass transport	miles	Vehicle odometer	Periodically (at least weekly)	
MPG	Transport vehicle gas mileage	miles / gallon	Measurement of vehicle miles traveled and gas usage	Start of program, and updated as needed	

Parameter	Description	Data Unit	How Measured	Measurement Frequency	Reported Measurement
V_{FF}	Volume of fossil fuels used to power biomass processing equipment, e.g. shredders, chipper, grinders, conveyors, loaders, excavators, bulldozers	gallons	Measurement of diesel fuel usage and/or equipment operating hours	Periodically (at least weekly)	
X_{OB}	Fraction of biomass that would have been open burned	%, wet biomass	Determined based on current economics and operating practices	Start of program, and updated as needed	
X_{DD}	Fraction of biomass that would have been left in field to decay and decompose	%, wet biomass waste	Determined based on current economics and operating practices	Start of program, and updated as needed	
X_{LF}	Fraction of biomass that would have been landfilled	%, wet biomass waste	Determined based on current economics and operating practices	Start of program, and updated as needed	

Form C. Reporting

Date:	
Project Title:	
Project Developer:	
Reporting Period:	

Parameter	Description	Data Unit	Reported Value
$BM_{DD, D}$	Biomass left in field to decay	bone dry tons	
$BM_{OB, D}$	Biomass open burned	bone dry tons	
$BM_{LF, D}$	Biomass landfilled	Bone dry tons	
$BM_{T, D}$	Biomass delivered to energy recovery facility, adjusted for moisture	bone dry tons / delivery	
$BM_{T, W}$	Biomass delivered to energy recovery facility	wet tons / delivery	
E_{BM}	Energy produced from energy recovery facility	kWh	
$EF_{DD, CH4}$	Emission factor for in-field decay and decomposition	tons CH_4/ton dry biomass	
$EF_{DD, N2O}$	Emission factor for nitrous oxide from in-field decay and decomposition	tons N_2O/ton dry biomass	
EF_E	Emission factor for CO_2e for existing electricity generation	tons CO_2e/unit energy	
EF_{FF}	Emission factor for fossil fuel combustion	lb CO_2/gallon fuel	
$EF_{OB, CH4}$	Emission factor for methane from open pile burning	tons CH_4/ton dry biomass	
$EF_{OB, N2O}$	Emission factor for nitrous oxide from open pile burning	tons N_2O/ton dry biomass	
$EF_{LF, CH4}$	Emission factor for methane from landfill	tons CH_4/ton dry biomass	
f	Energy production efficiency of energy recovery facility	net useful energy / biomass waste heat input	

Parameter	Description	Data Unit	Reported Value
GHG_{AUX}	GHG resulting from ancillary biomass handling, processing, and transport	tons CO_2e	
GHG_{BASE}	GHG resulting from baseline disposal practices	tons CO_2e	
GHG_{DD}	GHG resulting from decay and decomposition	tons CO_2e	
GHG_{E}	GHG displaced from energy production from biomass	tons CO_2e	
GHG_{NET}	Net GHG reductions from	tons CO_2e	
GHG_{OB}	GHG resulting from open burning activities	tons CO_2e	
GHG_{LF}	GHG resulting from landfilling activities	tons CO_2e	
GHG_{PROC}	GHG resulting from ancillary biomass handling and processing	tons CO_2e	
GHG_{PROJ}	GHG resulting from the biomass waste to energy project	tons CO_2e	
GHG_{TRANS}	GHG resulting from transport operations	tons CO_2e	
HHV_{BM}	Higher heating value of biomass	Btu/lb, dry	
M	Moisture content of biomass	moisture, wt. %	
MPG	Transport vehicle gas mileage	miles / gallon	
Q_{BM}	Heat content per delivery of biomass at facility	MMBtu	
R_{FF}	Average volumetric fuel use rate for processing equipment	gallons/hour	
T_{FF}	Time equipment used for processing operations	hours	

Parameter	Description	Data Unit	Reported Value
V_{FF}	Volume of fossil fuels used to power biomass processing equipment, e.g. shredders, chipper, grinders, conveyors, loaders, excavators, bulldozers	gallons	
VM	Vehicle miles traveled for biomass waste transport	miles	
X_{DD}	Fraction of biomass that would have been left in field to decay and decompose	%, wet biomass	
X_{OB}	Fraction of biomass that would have been open burned	%, wet biomass	
X_{LF}	Fraction of biomass that would have been landfilled	%, wet biomass	