December 13, 2011

Mr. Steven C. Riva
Chief, Permitting Section
US EPA Region 2
290 Broadway
New York, NY 10007-1866

RE: Alpine Energy Group, LLC.
AEG Anguilla Power, LLC
Renewable Energy Power Generation Project
Potential to Emit Calculations, Material & Energy Balance, Boiler Vendor Info

Dear Mr. Riva:

Beginning in February 2009, Alpine Energy Group, LLC (Alpine) has been in discussions with EPA Region 2 and the USVI Department of Planning and Natural Resources (DPNR) regarding a potential waste-to-energy project in the USVI. The AEG Anguilla Renewable Energy Power Generation Project (the "Project") would be located on the south shore of St. Croix, near the existing Anguilla Landfill. Although the proposed Project has gone through several revisions over the past three years, the general concept has been constant – Provide a cheaper, cleaner, and more effective form of power production to the USVI Water and Power Authority (VIWAPA) that does not rely on the combustion of fuel oil and address waste management issues that are inherent to the island environment. After extensive discussions with VIWAPA, USVI Waste Management Authority (WMA), and other interested stakeholders, Alpine believes that the proposed Project will achieve these goals.

The Project's criteria pollutant potential emissions are below the 100 tons per year threshold for each regulated pollutant; therefore, the proposed facility will not be subject to the requirements of Prevention of Significant Deterioration (PSD) under 40 CFR 52.21(b)(1)(i). Pursuant to the requirements of Title 12, Chapter 9, Section §206-20(a) of the Virgin Islands Air Pollution Control Act Rules & Regulations, Alpine submitted a combined preconstruction and minor source permit application to the USVI Department of Planning and Natural Resources (DPNR) in May 2010 for authorization of construction and operation of the proposed operations. Due to changes in the project design and updates from proposed equipment vendors, addendums to this application were submitted in December 2010 and September 2011. Additionally, Trinity Consultants, on behalf of Alpine, submitted an air impacts analysis protocol and significance results to EPA Region 2 in November 2011. This letter and associated attachments are intended to address previous questions and concerns identified by EPA Region 2, including:

- Heat Content of the Proposed Fuel;
- Material and Energy Balance Data; and
- Emissions Information from the Preferred Boiler Vendor.

BACKGROUND

The Project is in response to a request for proposal (RFP) issued by VIWAPA on May 1, 2008. The stated goals of the RFP process were to reduce costs of providing electricity to VIWAPA's customers and decrease VIWAPA's dependence on volatile oil prices. The RFP was open to all generation technologies except for oil-fired solutions. Alpine signed a power purchase agreement (PPA) with VIWAPA in August 2009. The original contract was based on a previously proposed project that would fire both RDF and petroleum coke, along with other supplemental fuels. Alpine and VIWAPA have since modified the design of the Project and removed petroleum coke from the project scope. A restated PPA between Alpine and VIWAPA for an RDF project was finalized in April 2011.

The Project is capable of providing electricity to VIWAPA at lower power generation costs than their current system and reduces dependence on fuel oil-fired power generation. The Project would offset approximately 400,000 barrels of oil annually that would otherwise be used to generate electricity under VIWAPA's current fleet of combustion equipment. The Project has the additional benefit of alleviating some of the waste management issues that are common to the island environment. In addition, the Project would enhance recycling in the USVI by returning glass, ferrous metals, and non-ferrous metals back to VIWMA that would otherwise be deposited in the Territory landfills. Additionally, VIWMA has been negotiating with EPA and Federal Aviation Administration (FAA) since the 1990s on waste management issues. One stipulation of these negotiations is an FAA mandate to close the Anguilla landfill on St. Croix by January 31, 2012. VIWMA also has plans to close the Bovoni Landfill on St. Thomas. Although this Project is only one piece of VIWMA's plan to improve waste management practices, the Project would assist the USVI with a long term solution.

Site and Equipment Description

The Project is to be located on property that Alpine has secured from the St. Croix Renaissance Group (SCRG) through a long-term commercial lease. The site consists of approximately 20 acres and is in close proximity to St. Croix' Anguilla landfill. The Project includes a MSW to RDF conversion process and one RDF fired steam generator, with a nominal steam rating of 225,000 lbs/hr, sending steam to a nominal 24 MW gross output, extraction/condensing steam turbine generator. The steam generator would also be capable of firing supplemental fuels such as tire-derived fuel (TDF), biomass, rum bottoms, and sanitary bio-solids (sewage sludge) in limited quantities. The maximum heat input of the steam generator is expected to be 300 MMBtu/hr. The Project would process up to 360 tons per day (tpd) of MSW supplied by the VIWMA. The MSW would be converted to RDF using the patented WastAway process.

The Project is designed for a nominal net electrical output of 16.5 to 20 MW after supplying steam and electrical power to a RDF processing facility. The Project would be designed to operate as a load dispatched facility at a net generating operating capacity between 6 MW and 20 MW. The Project would be constructed in accordance with local codes using all new equipment suitable for a 35-year project life. Local environmental conditions, such as humidity and hurricane-strength wind, will be considered in the design.

Because the Project would be located near the Virgin Islands Port Authorities Gordon A. Finch Molasses Dock, the Container Port, the SCRG Dock, and the HOVENSA refinery, a new dock for the facility would not be needed.

The Project would process MSW, which otherwise would have been deposited in the Anguilla landfill (or other landfill after Anguilla landfill closes). MSW would be delivered to an RDF preparation facility and will be sorted, processed, and delivered to the Project via conveyor. Non-processible waste (primarily white goods, glass, and metals) would be returned to VIWMA. RDF preparation will require the supply of auxiliary power and steam from the Project. During normal periods of operation, process steam to the RDF preparation facility will be supplied from the steam generator. During power plant outages, an auxiliary oil-fired boiler would supply the necessary steam for RDF processing. RDF would be stored in a covered storage building on the property.

Mobile equipment would be utilized to push both the RDF and other supplemental fuels to fuel reclaim systems. These fuels would be delivered via conveyors to day-bins and subsequently to metering bins which would supply fuel to the steam generating combustor (SGC). Start-up fuel for the facility would be ultra low sulfur diesel fuel, which would be delivered to the site via truck and stored within an on-site 150,000 gallon storage tank.

Nominal fuel input to the Project would involve 480 tons per day of RDF with a nominal, as-delivered, higher heating value of 7,500 Btu/lb. By limiting the annual capacity factor to 87% (2,286,360 MMBtu/yr), maximum annual fuel input is expected to be 152,424 tons per year. Additional detail on the proposed RDF is provided later in this letter. Note that Alpine also intends to investigate other opportunity fuels that may be available in the USVI. These supplemental fuels may include TDF, woody biomass, and sanitary bio-solids. Based on the assumption that these additional fuels do not present additional environmental concerns and that they are economically viable, Alpine has included these fuels in its air permit application to DPNR. Alpine does not expect to utilize these supplemental fuels at more than 5% of the heat input to the Project. Regardless of whether or not Alpine pursues these opportunity fuels, potential emission estimates are based on the worst case emission factors for RDF design fuel.

Steam would be generated from one SGC system followed by a heat recovery steam generator, multiclone for initial particulate removal, economizer for feedwater heating, and subsequent air quality control equipment. A dry scrubber utilizing hydrated lime sorbent feed placed downstream of the economizer would be used for sulfur dioxide (SO_2) and acid gas emissions control. The scrubber also assists in the abatement of hydrochloric acid (HCl) gases in the cooler zones downstream of the heat transfer equipment. A subsequent baghouse and activated carbon injection system would be installed for particulate emissions and mercury control, respectively. A selective catalytic reduction (SCR) system would be employed for nitrogen oxide (NO_x) emissions control.

The electrical output of the Project would be generated by means of an axial exhaust steam turbine with three stages of feedwater heating. The generator would be capable of producing at least 24 MW (gross). The exhaust of the steam turbine would be condensed via a steam surface condenser cooled by a wet cooling tower. The steam turbine would be enclosed in a turbine hall with appropriate parts lay down area and a bridge crane to facilitate turbine maintenance and overhaul. Ancillary power block equipment including feedwater heaters, boiler feed pumps, condensate pumps, air compressors, etc. would also be enclosed within this building. Discharge effluent from the wastewater treatment plant north of the landfill would serve to deliver all steam cycle make-up water, cooling tower make-up water, and other process water to the Project. The Project would use less than forty percent of the average daily outfall from the wastewater treatment plant. Make-up water for the steam cycle would be treated by a cycle make-up water system located in the water treatment area. Rainwater harvesting would provide additional water for potable water, dust suppression, and other uses. Although the 20-acre site of the Project is contiguous with SCRG's industrial park, the Project would be constructed and operated independently of the park, providing on its own all of the steam and electricity it needs to operate. Alpine would not contract with SCRG for the supply of any steam or electricity. Depending on market conditions, however, Alpine might purchase high quality water from SCRG on occasion, as opposed to obtaining such water directly or indirectly from the other available sources, such as VIWMA or VIWAPA.

The Project would result in a combustion waste by-product, *i.e.,* ash. This by-product is a combination of inert materials in the fuel, calcium oxide, and calcium sulfate. The ash material would be conveyed pneumatically from ash hoppers on the steam generator, multi-clone, economizer, dry scrubber, and the baghouse to common ash storage area. Approximately 10,000-15,000 tons of ash would be generated on an annual basis. This ash would be discharged to trucks for off-site disposal to be sold to an external firm for beneficial use as land reclamation, concrete additive, roller compacted concrete, etc. In the event that the ash cannot be re-used locally, Alpine would ship the ash to the mainland United States for re-use or disposal.

Power supplied from the Project would be interconnected with the 69 kV local grid system via a new local substation and new transmission line. The Project would be equipped with a black start generator capable of starting the Project during times when the power grid is out of service. Either this generator or the local grid can be utilized to support operation of the RDF processing facility if the power plant is out of service.

A Project warehouse and maintenance building would be provided for storage of spare parts and to facilitate equipment maintenance services. A material storage building would store all available fuels, including RDF, biomass, TDF, sanitary biosolids, rum bottoms, as well as ash. No ash or fuels with the potential to generate dust would be stored outdoors. In addition to mitigating potential fugitive dust emissions, the material storage building would keep RDF and other supplemental fuels dry. Appropriate security and fencing would be applied at the site access locations.

The area slated for the proposed facility is the former location of an alumina processing facility. As mentioned, Alpine has secured that area, approximately 20 acres, through a long-term commercial lease. The proposed facility is located at Latitude N17°42.571' and Longitude W64° 46.497'. The following location map depicts the project in reference to adjacent properties and island features as well as the jurisdiction line of the Department of Planning and Natural Resources, Division of Coastal Zone Management. The vicinity map also follows showing the regional context and vicinity in the U.S. Virgin Islands.

FIGURE 1. AREA MAP - LOCATION AND AGENCY REVIEW MAP, SHOWING THE COASTAL ZONE MANAGEMENT JURISDICTION IN COLOR

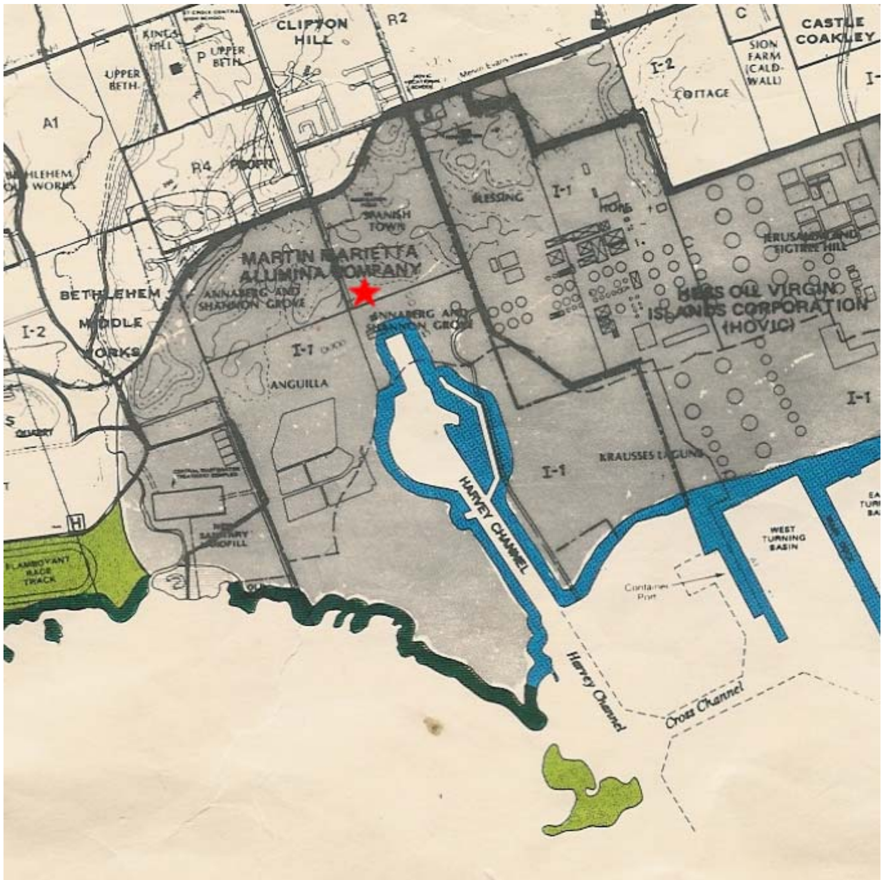
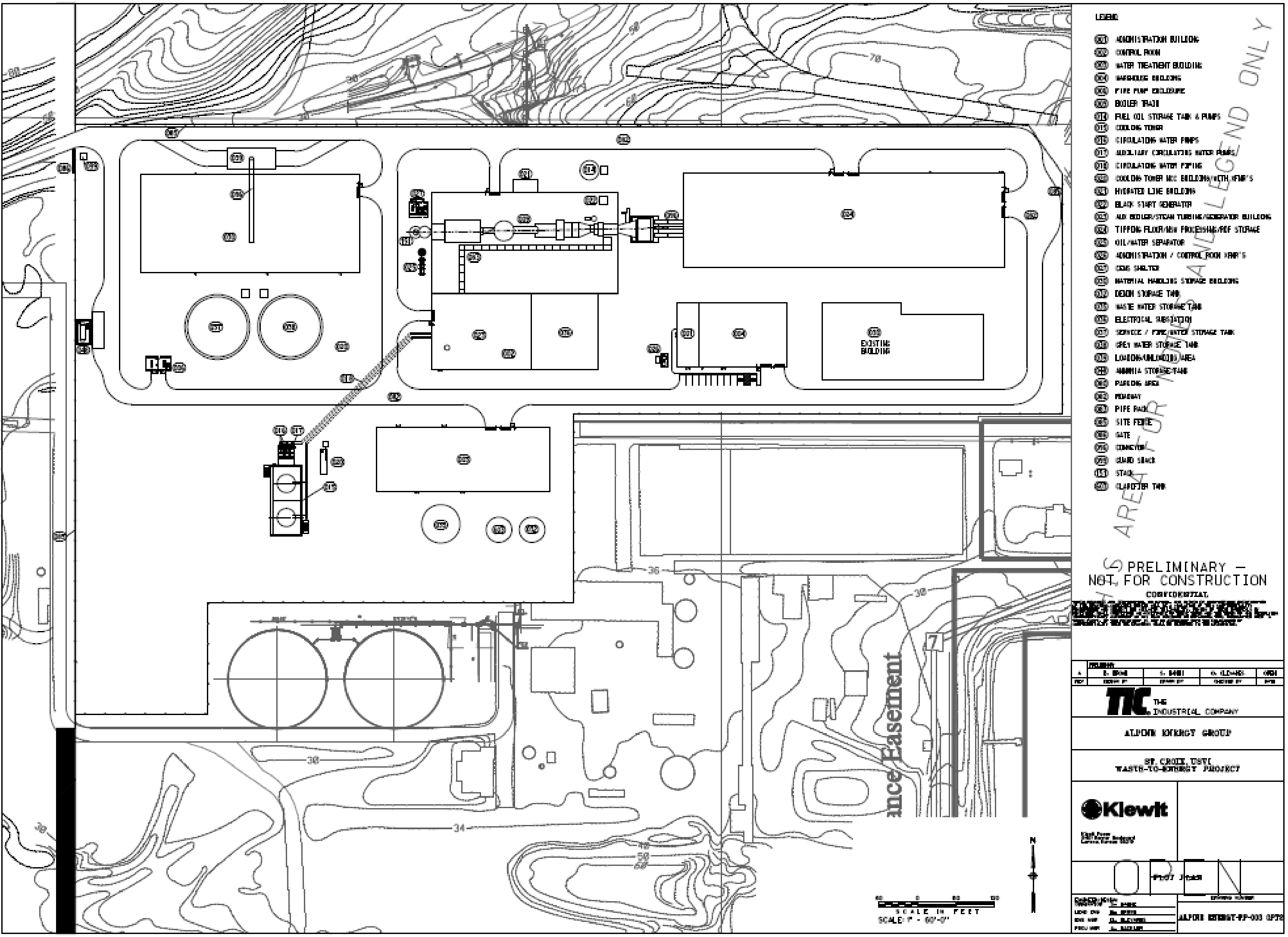


FIGURE 2. VICINITY MAP SHOWING THE PROJECT AREA IN REFERENCE TO OTHER ISLAND FEATURES

FIGURE 3. SITE LAYOUT



Fuel Characterization

The Project would utilize RDF as its primary fuel. The RDF feed rate would range from 12.5 to 25 TPH. The maximum charge rate of 25 TPH is based on a worst-case scenario heat content of 6,000 Btu/lb HHV. The average heating value of the RDF is expected to be at least 7,500 Btu/lb HHV. Therefore, the average full load heat rate is approximately 20 TPH. The remainder of the fuel feed necessary to reach the desired electrical output would come from biomass, TDF, sanitary biosolids, and rum bottoms. In addition to the MSW collected and utilized directly on St. Croix, the project would accept RDF from all available USVI sources including suppliers on St. Thomas, St. John, and Water Island. The following tables provide a characterization of the RDF. These data are based on information provided by Bouldin Corp, suppliers of the MSW to RDF conversion process. Note that the RDF characteristics are based on an operating RDF preparation facility in Tennessee. With the exception of the glass component, it is anticipated that these characteristics are generally applicable to MSW from the USVI, but site specific data for this Project has not yet been collected. One significant difference between the existing facility in Tennessee and the proposed facility for this Project is that the Alpine process would include an extra step to remove glass from RDF. Therefore, the glass component of the RDF for this Project would be lower than the value shown in Table 1.

Table 1 – RDF Characteristics

Fluff Characteristics	Percent in Fluff
Cellulose	60%-70%
Fabric and Thread	6%-16%
Plastic	8%-10%
Wood, Metal, Stone, and Glass[1]	7%

[1] Estimated composition without glass removal process

Table 2 – RDF Elemental Analysis

pH		6.5	Fe	mg/Kg	2,460
C/N		32	Mn	mg/Kg	130
C	%	39.8	Zn	mg/Kg	234
N	%	1.26	B	mg/Kg	35
P	mg/Kg	1,900	Cu	mg/Kg	47.7
K	mg/Kg	2,170	Co	mg/Kg	2.0
Ca	mg/Kg	13,600	Na	mg/Kg	5,169
Mg	mg/Kg	1,400	Pb	mg/Kg	65.4

Table 3 – RDF Heat Content Analysis

Date	Location	Heat Content As Received (Btu/lb)	Heat Content Dry Basis (Btu/lb)	Moisture (%)
8/1/2005	TN	9,077	9,650	5.94
3/3/2009	TN	8,163	8,879	8.06
5/7/2009	Canada	7,660	8,232	6.95
5/12/2009	TN	8,443	8,908	5.22
5/12/2009	TN	7,697	8,114	5.14
5/12/2009	TN	7,474	7,910	5.51
5/12/2009	TN	8,282	8,794	5.82
5/12/2009	TN	8,647	9,128	5.27
9/3/2009	Aruba	7,628	8,337	8.51
5/3/2010	TN	6,380	6,806	6.26
5/3/2010	TN	7,683	8,188	6.17
5/3/2010	TN	8,811	9,359	5.85
6/28/2010	TN	9,266	9,978	7.14
6/28/2010	TN	8,601	9,354	8.05
6/28/2010	TN	8,539	9,202	7.21
6/28/2010	TN	8,270	8,964	7.74
Average		8,164	8,738	6.55

The WastAway process provides substantial advantages over traditional mass burn or RDF incineration facilities in the form of higher heat content, MSW sterilization, improved handling and transportation, reduced moisture content, etc. The developer and supplier of the process, Bouldin, has produced two WastAway systems operating on a commercial basis. One system is located in Warren County, Tennessee, and the second system is located in Aruba. Although the Fluff generated by those two systems is not currently used for power generation, Bouldin has tested RDF pellets produced from both systems. The majority of the RDF tested was generated from MSW collected in Warren County. Additionally, Bouldin has tested RDF pellets produced by WastAway from Aruba and Canada (MSW shipped from Canada to TN and then converted to RDF). The results of these tests are presented above in Table 3.

As mentioned previously, neither WastAway system currently removes glass. Based on waste characterization studies provided by VIWMA, the glass/inert fraction of the incoming MSW stream is expected to be approximately 5.4%. Factoring in the removal of this glass/inert fraction, the average heat content of 8,164 Btu/lb presented in Table 3 would be more than 8,500 Btu/lb. Therefore, Alpine believes that the nominal heat content of 7,500 Btu/lb is conservative and appropriate for design purposes. Furthermore, the Project is designed with covered conveyors and storage buildings to keep the RDF dry. Any RDF transported from St. Thomas to St. Croix, which would be produced through the WastAway process, would be shipped in covered vessels to also keep the fuel dry and prevent spillage.

The heat content of the RDF produced through the WastAway process conceivably could drop as low as 6,000 Btu/lb on a short-term (hourly) basis. For example, two individual samples of the sixteen samples shown in Table 3 have a heat content less than 7,500 Btu/lb (May 12, 2009 and May 3, 2010). However, the daily average heat content for both of these days is higher than 7,500 Btu/lb. Although the heat content may occasionally drop below the predicted design value, a temporarily reduced heat content would not materially impact emissions from the main boiler when calculated on the basis of 30-day or annual averages. Moreover, these fluctuations in heat content would primarily impact NO_X, CO, VOC, and SO_2 emissions. Of these pollutants, only NO_X and CO are relatively close to the 100 tpy PSD threshold (81 tpy and 94 tpy, respectively). The proposed pollution control equipment combined with continuous emissions monitors for both NO_X and CO would allow Alpine to adjust the ammonia injection and combustion conditions on a real time basis to ensure compliance with the proposed emission limits.

Material & Energy Balance

Alpine anticipates that the Project would generate nearly 100% of its electricity output from the combustion of RDF. A preliminary material and energy balance based on the combustion of RDF is provided as Attachment A. Given the limited amount of other opportunity fuels, Alpine does not anticipate that these fuels would materially impact the energy balance.

The energy balance predicts that the Project would generate a maximum net output of 20,322 kW at a heat input of 300 MMBtu/hr. This equates to a net heat rate of 14,763 Btu/kW-hr including all auxiliary loads. The anticipated boiler efficiency is 80.1% and the anticipated steam turbine efficiency is 32%. This energy balance is preliminary and not yet been optimized. The preliminary energy balance was developed using the following mass flow rates and steam conditions:

- 20 tons per hour RDF feed
- 300 MMBtu/hr heat input
- 225,000 lb/hr steam @
- 830°F
- 1,150 psia
- 23,832 gross electric power
- 20,322 net electric power

Ultimately, the net output and heat rate would be determined based on detailed design engineering work. Alpine is currently negotiating a contract with an Engineering, Procurement, and Construction (EPC) contractor. Upon completion of the final design, the EPC contractor would guarantee a net heat rate and output. These guarantees would be based on the original equipment manufacturer guarantees provided by the boiler and steam turbine vendors.

Certain conditions and design criteria ensure compliance with the proposed permit emission limits, which demonstrate that the facility-wide emissions would be less than 100 tpy (see Attachment B). For example, the EPC contractor would be limited to a maximum heat input of 300 MMBtu/hr as part of the final design. Although a higher heat input would certainly increase the net output of the facility, only improvements to the efficiency (heat rate) would be considered to increase the output, and the maximum heat input is fixed. At this time, Alpine's predicted performance exceeds the minimum net output to WAPA of 16.5 MW. Therefore, Alpine does not anticipate any reason to increase the heat input beyond 300 MMBtu/hr.

The RDF feed rate to generate the maximum net output of 20 MW would be 20 tons per hour. Factoring in the MSW to RDF conversion rate of 75%, this electric output to fuel ratio is equal to 750 kW-hr/ton MSW. Pending final design, it's reasonable to anticipate this ratio could range from 675 to 750 kW-hr/ton MSW. This range exceeds the minimum contract guarantees to VIWAPA. While this ratio is higher than that commonly experienced by WTE facilities in the United States, *i.e.,* 525-615 kW-hr/ton MSW, the majority of those facilities were primarily designed to consume MSW. Power generation was a secondary benefit. For the unique situation in the USVI where the only source of power generation comes from fuel oil combustion, the value of energy production is a premium compared to the mainland United States. Therefore, Alpine chose to optimize fuel preparation, combustion efficiency, and steam conditions to maximize the potential power generation of the project, resulting in a more costly facility. However, the increased efficiency and output justifies that higher cost.

Major Equipment Vendors – B&W

Alpine is proposing to install one stoker-fired steam generating combustion (SGC) unit that would be designed and manufactured by B&W. A world leader in the WTE industry, B&W has supplied 62 units operating on RDF in North America. The equipment would consist of a steam generator with a capacity of 225,000 lb/hr steam. The maximum heat input of the SGC is 300 MMBtu/hr. Steam produced by the SGC would feed into a steam turbine generator, producing a nominal net electrical output of 16.5 to 20 MW after supplying steam and electrical power to a RDF processing facility and other auxiliaries. The rationale for selecting stoker-fired technology is as follows.

Overview

The project is designed with an advanced stoker-fired combustion system to maximize fuel flexibility. Stoker-fired combustion systems are located throughout the world in the industries of power generation, wood products, paper, agriculture, food processing, and in municipalities recovering energy from wastes such as municipal garbage and sludge, paper, paper sludge, coal, plastic, manure, biomass, wood, and numerous other materials. The stoker design is suitable for burning a wide range of materials containing predictable moisture contents while generating the lowest possible emissions.

Advanced Stoker-Fired Combustion Process Description

The advanced stoker-fired boiler technology is a reliable and proven technology for the conversion of waste fuels to electricity. The design of the boiler ensures a complete and efficient combustion process. The fuel feed design provides an evenly distributed fuel feed along a vibrating grate, which maintains proper air/fuel ratios. The advanced design allows for higher combustion temperatures and even temperature distribution. Air flow within the combustion zone and leakage around the periphery of the boiler are properly maintained and/or minimized. The advanced furnace design allows for increased mixing and turbulence, as well as residence time in the combustion zone. These advanced designs represent over 40 years of technology improvements in the stoker-fired boiler industry to maintain compliance with the most stringent air quality regulations.

The evolution of stoker-fired boilers in combination with proven, reliable, and effective air quality control systems (AQCS) has resulted in a combustion technology that has transformed incineration of a nuisance waste into combustion of a valuable fuel. Modern stoker combustion systems include a stable combustion process which maximizes boiler efficiency while minimizing emissions. Time, temperature, and turbulence are the three key characteristics of waste combustion that influence emissions. The advanced stoker-fired design that Alpine proposes for this Project focuses on optimizing the aforementioned characteristics and installing the best available control technologies available to reduce emissions to the atmosphere.

Combustion Efficiency and Emissions

The advanced stoker design ensures an even distribution of fuels across the vibrating grate. This improved distribution and grate design allows for better air/fuel ratio control, higher combustion temperatures, and reduced maintenance costs. The advanced furnace design increases mixing, turbulence, and residence time within the combustion zone. These characteristics increase the overall efficiency of the boiler. As a result, CO and VOC emissions are minimized. Although the increased combustion temperature and efficiency can enhance NO_X formation within the furnace, downstream SCR control would be used to mitigate NO_X emissions.

The advanced stoker boiler design in combination with a modern AQCS consistently meets the world's most stringent emissions constraints. The AQCS that Alpine has proposed far exceeds the requirements of NSPS Subpart Eb.

Major Equipment Vendors – Bouldin Corporation

Equipment provided by the Bouldin Corporation (Bouldin) would be used to convert MSW into RDF. This equipment, known as the WastAway process, was developed, patented, and is currently owned by Bouldin & Lawson, a manufacturing company that invented heavy-duty shredders and machines for use by commercial nurseries. The WastAway process takes unsorted MSW and converts it into a product called Fluff, which is similar in consistency to wood pulp. After pelletizing, the RDF would then be used to feed the B&W SGC envisioned for the Project. Approximately 75% of the MSW fed into the process is converted to RDF. Covered storage facilities would be provided for both RDF Fluff and Pelletized RDF, in part to minimize moisture content.

Bouldin and its subsidiaries have a fifty year history as an innovative manufacturer and systems integrator for diverse systems in the horticulture, recycling and military industries. The WastAway technology proposed for the Project was originally developed in cooperation with the Corps of Engineers Research Lab, (CERL) in the late 1990's to process waste generated on stationary military bases. In June of 2003 Bouldin entered into a contract with Warren County, Tennessee to process all of their residential household garbage.

The WastAway process has been used to successfully recycle all unsorted household garbage on a commercial scale for Warren County, Tennessee from 2003-2009. During these six years, it has been used to recycle over 30,000 tons of MSW. This process, which would be substantially similar in nature to the system that Alpine intends to install for the Project, does not require an expensive MSW sorting operation. Rather, MSW would be delivered to the Project by the usual VIWMA collection vehicles, where it would be dumped onto the tipping floor for an initial pre-sort to remove large unacceptable waste items such as refrigerators, washing machines, appliances and similar White Goods. There is no further sorting or preprocessing at the tipping floor, and all remaining MSW is directed into the processing system, which includes a series of conveyors, shedders, grinders, and the company's patented hydrolyser in which the shredded MSW is sterilized by 125 psig saturated steam. The WastAway process removes metals and glass fraction contained in the MSW, which would be available for beneficial re-use or recycling. Pelletizing equipment would be installed to produce the RDF which would be fired in the SGC. The following sections provide additional information on some of the unique aspects of the WastAway process.

WastAway Hydrolyzer

The hydrolyzer operates similarly to an autoclave, in that steam is used to pressurize and sterilize the processed RDF. Unlike a conventional autoclave, the system operates in a near continuous mode injecting and removing "plugs" of RDF while maintaining pressure within the hydrolyzer. Additionally, by allowing the pressurized Fluff to rapidly decompress, cellulose components of the RDF are explosively decomposed adding to the unique nature of the RDF. Overall residence time in the hydrolyzer is approximately 20 minutes. Saturated steam at 125psi is injected into the pressure chamber. Additional steam is used in a steam jacket surrounding the vessel to vaporize moisture in the RDF, thereby reducing water consumption.

Inert Extraction

In order to reduce maintenance and improve fuel heating value, the proposed configuration would be slightly modified from the operating system in Warren County. Metals extraction would be accomplished much earlier in the process, thus reducing wear on downstream sizing equipment and improving efficiency of the metal extraction.

A glass extraction stage is also included for the Project. Bouldin and their research partners are currently analyzing multiple proven technologies to select the best fit for integration into the process line. Glass extraction can be expected to reduce wear on downstream components significantly and would also increase the heating value of the fuel produced. Companies currently under consideration as the glass extraction provider include CO.F.A.M.M. of Italy, General Kinematics, Action Equipment, and BHS.

Pelletization

Bouldin began working on the pelletization process in late 2006 with R&D assistance from Battelle Memorial Institute. In 2007 they begin collaborating with Andritz Sprout Bayer to prove commercial viability of Fluff pelletization. In August of 2007 a week of trials were conducted at Andritz laboratories in Pennsylvania. This was followed by three commercial trials at third-party wood pelletizing facilities contracted by Bouldin. Approximately 30 tons of pellets were produced in these third-party trials.

Based on the success of the earlier trials, Bouldin purchased and installed a 400 Hp Andritz pellet mill at their Morrison facility in October 2008. The company is now working with Andritz to optimize die design, material feed systems, and other aspects of the pelletizing process. Andritz's European division is knowledgeable about RDF pelletization and is advising the company in the optimization of this portion of the system. To date approximately 150 tons of pellets have been produced at the Warren County facility. The current pellets are ¼" in diameter as this size is required in some Canadian combustion tests scheduled for April 2009. Andritz is currently researching appropriate die modifications to produce a larger diameter pellet for testing. Optimum pellet size for this project would be determined in conjunction with B&W, the combustion equipment provider.

Unit Operations

A description of the WastAway unit operations that comprise the process line is provided below:

1. **Bag Breaker:** Equipment designed to open garbage bags and spill contents onto conveyor with minimal breakage and shredding of material.
2. **Ferrous Metal Removal:** This process uses a series of magnets and conveyors to separate the ferrous metals from the waste stream. Ferrous metals removed will be conveyed to 30 yard roll-off containers for transport off site.
3. **Non-Ferrous Metal Removal:** Eddy current devices are used to remove non-ferrous metals from the process stream.
4. **Preshredder:** Twin axle shredder used to size material to 4" minus. Specifically useful in crushing glass bottles to allow for efficient removal during the inert extraction phase.
5. **Inert Extraction:** This process will utilize air classifiers or conventional screening processes to remove glass, rocks and other inert materials from the process flow. Inert materials removed will be conveyed to 30 yard roll-off containers for transport off site.
6. **Primary Sizing:** This step will utilize a quad shredder to reduce the size of the material to ¾" minus.
7. **Hydrolyzer:** The continuous-flow hydrolyzer uses a combination of steam and pressure to further decompose the waste stream. The hydrolyzer chamber uses live steam injection and a steam heated jacket to generate the required pressure and temperature for adequate processing. Once the processed waste exits the chamber it is allowed to rapidly expand from 125 psi to atmosphere further aiding the decomposition of the waste material. Upon exit from the hydrolyzer, many of the characteristics of the original input

have been significantly altered. RDF exiting the hydrolyzer is homogeneous, non-putrescent and stable.

8. **Final sizing:** RDF is further processed through a grinder and/or shredder to insure material is adequately sized for pelletzing process.
9. **(Optional) Dryer:** To optimize pelletizing process a dryer will be included, if required, to reduce moisture of the RDF to approximately 15% by weight. Heating can be accomplished using low pressure steam from the power island.
10. **Pelletizer:** Pellet mills developed by Andritz will be used to convert the RDF from its normal fibrous state to a dense ¼”- ½” diameter pellet. Exact pellet size will be optimized to reduce energy and maintenance costs while maximizing combustion efficiency and material handling characteristics of the RDF pellets. Once produced RDF will be either mechanically or pneumatically conveyed to fuel storage area. The final moisture content is expect to be approximately 8%.

Pollution Control Technologies

Pollution control for the SGC installation would be accomplished through the combined effect of the following provisions in the order of the flue gas flow:

- Multiclone downstream of the heat recovery steam generator for initial particulate removal
- Dry scrubber with hydrated lime and activated carbon injection for SO_2, acid gas, dioxin/furan, and mercury removal
- Pulse-jet fabric filter for final acid gas polishing and particulate removal
- Selective catalytic reduction for removal of NO_X

Due to the nature of the advanced stoker boiler combustion process, air emissions from the Project are inherently low. The versatility of the advanced design, with its extended residence time, turbulence, and temperature, minimizes the production of most emissions and allows for the application of various abatement techniques to further reduce various pollutants. The products of incomplete combustion (PIC) such as carbon monoxide (CO), volatile organic compounds (VOC), total hydrocarbons (THC), dioxins and furans (PCDD and PCDF), are minimized due to the high combustion efficiency of the process.

Multiclone

A multiclone, or a multicyclone, is a series of small-diameter cyclones (usually three to twelve inches in diameter), operated in parallel. A cyclone is a mechanical collector that utilizes centrifugal force to collect particulate matter. The gas stream typically enters the top of the cyclone tube and is forced into a circular flow pattern towards the bottom of the cyclone. This can be accomplished by use of an induced draft fan on the clean gas stream side of the cyclone (negative pressure) or a forced draft fan on the dirty gas stream side of the cyclone (positive pressure). The centrifugal force of the gas stream, caused by the circular flow pattern, drives the particulate matter towards the sides of the cyclone, where it falls into a collection hopper.[1] Because a cyclone with a small diameter has a greater removal efficiency than one with a large diameter (usually one to six feet), a multiclone design would allow gas streams with high gas flow rates to be treated more efficiently. This results in much higher collection efficiency for particles less than 10 microns in diameter (PM_{10}). A multiclone system downstream of the heat recovery steam generator would achieve particulate control efficiency of 99% in conjunction with the fabric filter baghouse.

Dry Scrubber

The dry scrubber or spray dryer absorber would be located upstream of the fabric filters. The flue gas passes through a spray dryer vessel where it encounters a fine mist of hydrated lime slurry. The hydrated lime slurry is injected into the spray dryer absorber through either a rotary atomizer or dual fluid nozzles. As the water in the slurry droplets evaporates in the flue gas, SO_2 and acid gases are absorbed into the droplets and reacts with the hydrated lime to form insoluble calcium salts. Once the water is evaporated, solid particles composed of calcium sulfite, calcium sulfate, other acid gas salts, and unreacted hydrated lime exits the dry scrubber and is collected in the downstream particulate removal device. When a fabric filter is used as the particulate control device, it allows for further reaction of the lime with the SO_2 (and other acid gases) in the flue gas. This is due to the layer of porous filter cake on the surface of the filter bags that contains excess alkalinity (in the form of unreacted hydrated lime and alkaline fly ash from the fluid bed boiler) that the flue gas is drawn through. This removal mechanism is efficient for control of sulfuric acid mist and hydrogen chloride, and is considered to be much more effective than that of wet scrubbers. This control approach is expected to reduce SO_2 emissions by 90%-95% and reduce acid gas emissions by more than 95%.

Activated Carbon Injection

Mercury emissions are expected to be relatively low due to the inherent control of the SGC process and co-benefit of the spray dryer and fabric filter combination. Although initial estimates predict that additional mercury control is not necessary to comply with the NSPS Subpart Eb limit, Alpine would also control mercury emissions by the injection of activated carbon into the flue gas prior to passing through the fabric filter. The activated carbon adsorbs the vaporized mercury from the flue gas and is then collected with the fly ash in the plant's fabric filter baghouse. The control efficiency of the sorbent injection is expected to be greater than 90%.

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[1] U.S. EPA, Basic Concepts in Environmental Sciences, Module 6: Air Pollutants and Control Techniques, Particulate Matter - Control Techniques, 2 Mar 2006,

Fabric Filter

A fabric filter system would be used for final acid gas polishing and particulate removal. In a fabric filter, flue gas is passed through fabric, causing PM in the flue gas to be collected on the fabric by sieving and other mechanisms. Fabric filters are typically in the form of bags, with a number of the individual fabric filter units housed together in a group. Groups of bags are placed in isolatable compartments to allow cleaning of the bags or replacement of some of the bags without shutting down the entire fabric filter. [2]

The fabric itself performs a portion of the filtering, but its main role is to be the support media for the filter cake that develops on its surface. The filter cake is responsible for the efficient filtering of fine particulate. The particulate reaching the filter cake would contain some quantity of unreacted lime from the dry scrubber located upstream of the baghouse. This material would continue to provide additional control of SO_2 and acid gases since flue gas from the boiler would be filtered through this material in the filter cake.

The filter cake must be periodically removed from the fabric filters so that a reasonable pressure drop across the baghouse can be maintained. Alpine intends to use a pulse-jet cleaning method in the SGC unit baghouse. There are several unique attributes of pulse-jet cleaning. Because the cleaning pulse is very brief, the flow of dusty gas does not have to be stopped during cleaning. The other bags continue to filter, taking on extra duty because of the bags being cleaned. In general, there is no change in fabric filter pressure drop or performance as a result of pulse-jet cleaning. This enables the pulse-jet fabric filters to operate on a continuous basis with solenoid valves as the only significant moving parts. Pulse-jet cleaning is also more intense and occurs with greater frequency than the other fabric filter cleaning methods. This intense cleaning dislodges nearly all of the dust cake each time the bag is pulsed. As a result, pulse-jet filters do not rely solely on a dust cake to provide filtration. Felted (nonwoven fabrics) are used in pulse-jet fabric filters because they do not require a dust cake to achieve high collection efficiencies.

Since bags cleaned by the pulse-jet method do not need to be isolated for cleaning, pulsejet cleaned fabric filters do not need extra compartments to maintain adequate filtration during cleaning. Also, because of the intense and frequent nature of the cleaning, they can treat higher gas flow rates with higher dust loadings. Consequently, fabric filters cleaned by the pulse-jet method can be smaller than other types of fabric filters in the treatment of the same amount of gas and dust, making higher gas-to-cloth ratios achievable.

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[2] The fabric filter description is modified from an EPA Air Pollution Control Technology Fact Sheet for Pulse Jet Fabric Filters, EPA=452/F-03-025.

Selective Catalytic Reduction

To control the NO_x produced by the fuel bound nitrogen as well as thermal NO_X generated in the furnace, the Project would utilize SCR for NO_x abatement. Selective Catalytic Reduction (SCR) is a post-combustion gas treatment process in which 19 % aqueous ammonia (NH_3) is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, ammonia and NO_x react to form diatomic nitrogen and water. The primary chemical reactions can be expressed as follows:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$4NH_3 + 2NO_2 + 2O_2 \rightarrow 3N_2 + 6H_2O$$

When operated within the optimum temperature range of 575 to 750 °F, the reaction can result in removal efficiencies between 70 and 90 percent. Operation outside the optimum temperature range can result in increased ammonia slip or increased NO_x emissions. SCR units have the ability to function effectively under fluctuating temperature conditions (usually ± 50 °F), although fluctuation in exhaust gas temperature reduces removal efficiency slightly by disturbing the chemical kinetics (speed) of the NO_x -removal reaction. This control method is expected to achieve at least a 70 percent or greater reduction in NO_x emission levels.

Alpine is not aware of any WTE facilities in the Unities States currently using SCR to reduce NO_x emissions from RDF combustion. However, SCR is commonly used on coal-fired units. Additionally, WTE facilities in Europe have been using SCR over the past 15 years. Additional information related to NO_x emission from these European facilities is provided in Attachment C.

Proposed NO_x emissions from the project are approximately 50 ppmdv (7% O_2). B&W has confirmed this emission target and would eventually guarantee these NO_x levels as part of the boiler supply contract. As demonstrated by WTE facilities utilizing SCR in Europe, NO_x emissions can range from 20 to 70 mg/Nm^3 (15 to 50 ppmdv at 7% O2). Based on emission levels reported in Europe and emission guarantees from B&W, Alpine is confident that the proposed emission limit of 19.5 lb/hr (50 ppmdv) is readily achievable using modern SCR pollution control.

Continuous Emissions Monitoring System

A self-contained continuous emissions monitoring system (CEMS) with climate-controlled shelter would be used to monitor emissions in accordance with applicable regulations. The equipment would be designed, fabricated, tested, and field certified in accordance with applicable parts of U.S. Environmental Protection Agency 40 CFR Parts 60 and 75. All required reporting would be handled from a single data acquisition system (DAS) located in the Central Control Room.

The CEMS would analyze and monitor in the exhaust gas from the steam generator as the gas passes through the stack. Concentration levels of oxides of nitrogen (NO_x), Sulfur dioxide (SO_2), carbon monoxide (CO), and opacity would be continuously monitored by the system. Concentration levels of oxygen (O_2) or carbon dioxide (CO_2) would also be monitored continuously as a diluent gas.

The CEMS for the SGC would consist of the following major components:

- Climate Controlled Shelter
- Extractive Sample Retrieval Systems
- Sample Conditioning System
- Analyzer Rack
- CEM System Controller
- Stack Mounted Extraction Probe
- Duct Opacity Monitor
- Stack Mounted Gas Flow Monitors
- One Set of Calibration Gas Cylinders and Regulators
- Data Acquisition System

Emission Estimates

Emissions of criteria air pollutants from the proposed SGC unit and other supporting equipment associated with the project are summarized in this section. In addition to the main combustion unit, emissions are generated from diesel-fired support equipment, material processing and handling of limestone/hydrated lime and ash, cooling tower emissions and from vehicular traffic. Emission calculations are discussed below and supporting documentation is provided in Attachment B of this report. Unless otherwise noted, emission estimates are based on continuous operation at maximum capacity of the unit.

SGC Unit Emissions Calculations

The proposed SGC unit would primarily emit SO_2, PM_{10}, $PM_{2.5}$, CO, and NO_x, with smaller amounts of VOC and HAP emissions. Potential emissions are based on the maximum heat input rating for the SGC unit and the emission guarantees provided by B&W. The emission guarantees provided by the SGC vendor reflect the worst case emission factors for the range of expected fuel blends. Furthermore, the emission factors reflect the post-controlled emission rates for NO_x, SO_2, $PM_{2.5}$ and PM_{10}. NO_x emissions would be controlled through utilization of SCR and SO_2 emissions would be primarily controlled by injecting hydrated lime into a scrubber system. An Activated Carbon injection system would be used to control emissions of mercury from the process. The filterable portion of PM would be controlled through a baghouse. The WastAway process would emit PM and VOC emissions as a result of operations; however the effluent stream would be directly routed to the combustion chamber of the SGC for destruction and control. The potential emission presented for the SGC also includes all controlled emissions from the WastAway process.

Alpine is actively working with B&W to negotiate a contract for the main combustion equipment and pollution controls. The contract would have emission guarantees set at or below the proposed permit limits. These contract provisions would be "Make Right" guarantees, meaning that B&W would not have the ability to pay damages for a higher emission guarantee. B&W has provided a letter indicating their target guarantees (Attachment D). The contract with B&W will be in place prior to the commencement of construction. A comparison of the target emission guarantees provided by B&W and the proposed emission limits is provided in Table 4.

Table 4 – B&W Target vs. Proposed Emission Limits

Pollutant	B&W Guarantee Target (lb/hr)	Proposed Emission Limit (lb/hr)
NO_X	18.9	19.5
SO_2	10.2	10.5
CO	23.1	24.0
PM_{10} (Total)	7.2	8.7
VOC	14.4	15.0

A summary of emissions of all pollutants from the proposed SGC unit is contained in Attachment B, Table B2. The facility would monitor fuel throughput of RDF and other opportunity fuels. Actual emissions of NO_x, SO_2, and CO would be recorded by a continuous emissions monitoring system. Annual emissions are based on an operational restriction of 87% capacity factor.

Material Handling Emissions

A variety of material handling support equipment would be constructed at the facility. This equipment would be used primarily for the handling, transport, and storage of RDF, hydrated lime, and ash. These activities are a source of fugitive and point source particulate matter emissions. Point source emissions are emissions that exhaust through a dust collector. Fugitive particulate emissions are calculated using methodologies and emission factors published in EPA's AP-42[3] compilation document and other references. Point source emissions through dust collectors are based on vendor guaranteed outlet grain loading and the design flow rate (acfm). Total estimated emissions from all material handling equipment are listed in Tables B7 and B8 of Attachment B.

Ancillary Combustion Equipment Emissions

Emissions of criteria pollutants and HAPs are generated from the No. 2 fuel oil fired auxiliary boiler, firewater pump, and black-start generator. EPA Tier 3 Diesel Engine Emission Standards and manufacturer guaranteed emission factors were utilized for NO_x, CO, and VOC emission factors are utilized for the black-start generators and firewater pump. Annual emissions from the auxiliary boiler are based on 4,000 hours of operation. Annual emissions

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[3] AP-42, Fifth Edition, Volume I, Section 13.2.4, Aggregate Handling and Storage Piles, was used to estimate the Material Handling Emissions. AP-42, Fifth Edition, Volume I, Section 13.2.1, Paved Roads, was used to estimate the fugitive emissions due to vehicle traffic.

from the black-start generator and fire pump are based on 500 and 100 hours of operation, respectively. Tables B4, B5, and B6 of Attachment B contain the emission calculations for the Auxiliary Boiler, Black-Start Generator, and Fire Pump, respectively.

Cooling Tower Emissions

Cooling towers produce PM emissions when water droplets evaporate, leaving the dissolved solids in the water as PM. Emissions from the cooling towers are based on the emission factor and calculation procedures of AP-42 Section 13.4 and U.S. EPA $PM_{2.5}$ Speciation Guidance, October 7, 1999 and shown in Table B9 of Attachment B. Discharge effluent from the wastewater treatment plant north of the landfill would serve to deliver all the steam cycle make-up water, potable water, and cooling tower make-up water needs to the Project.

Vehicle Traffic Emissions

Consistent, production-related traffic within the facility would be due to the transportation of MSW, receipt of raw materials such as fuel oil, activated carbon, and various other chemicals, and shipment of ash and wastes offsite. It can be conservatively assumed that any other sources of road emissions (e.g., passenger vehicles) are accounted for in the estimates for these main traffic streams. It is assumed for permitting purposes that all roads would be paved. Emissions are estimated using AP-42 Section 13.2.1 *Paved Roads* (11/06) and shown in Table B10 of Attachment B.

Storage Tanks

The project would consist of a 150,000 gallon fuel oil storage tank and a 30,000 gallon aqueous ammonia storage tank. The annual emissions associated with these tanks were estimated using EPA's TANKS 4.0.9d program. The tanks' design details and the proposed emissions are shown in Table B11 of Attachment B. Additional chemicals necessary for process operation would be delivered and stored on-site in 250-gallon totes.

GHG Emissions

The Project would generate Greenhouse Gases, CO_2, CH_4, and N_2O. As per the EPA's final GHG reporting rule, CO_2 emissions from all applicable combustion sources within this project would be monitored, quantified, and reported in accordance with EPA's Mandatory Reporting Rule, 40 CFR 98. However, it should be noted that this facility would be utilizing municipal solid waste (MSW) as a primary fuel for the boiler. Under EPA's final GHG reporting rule, emissions of CO_2 from the biomass material in MSW are defined as biogenic CO_2 and considered carbon-neutral. As designed, the Project would make use of opportunity renewable fuels, such as wood biomass that are also deemed carbon neutral. The fuels proposed in this application would also result in a reduction of methane produced from the adjacent landfill, which would have otherwise received the MSW or biomass for processing and disposal. A summary of the potential GHG emission calculations from the project is found in Attachment B.

Facility-wide Emissions Summary

Table 5 below provides a summary of the potential annual emissions from the proposed facility taking into account physical and operational restrictions. As shown below, facility-wide emissions are less than the PSD major source threshold of 100 tpy.

Table 5 – Facility-wide Emissions Summary

EU Description	**Total PM (tpy)**	**Total PM_{10} (tpy)**	**Total $PM_{2.5}$ (tpy)**	**NO_X (tpy)**	**SO_2 (tpy)**	**CO (tpy)**	**VOC (tpy)**
SGC Unit	33.15	33.15	17.15	74.31	40.01	91.45	57.16
Auxiliary Boiler	1.18	0.36	0.09	5.00	0.08	1.95	0.25
Black Start Generator	0.04	0.04	0.04	1.48	0.008	0.43	0.30
Firewater Pump	0.03	0.03	0.03	0.09	0.00	0.09	0.00
Dust Collectors	3.57	3.57	3.57	--	--	--	--
Drop Points	0.02	0.01	1.72E-03	--	--	--	--
Cooling Tower	2.33	0.93	0.12	--	--	--	--
Storage Tanks	--	--	--	--	--	--	0.03
Vehicle Traffic	2.92	0.57	0.09	--	--	--	--
Total	***43.25***	***38.66***	***21.08***	***80.88***	***40.10***	***93.92***	***57.74***

Emission Monitoring and Reporting

Alpine understands that EPA Region 2 must be assured that facility-wide emissions will be less than 100 tpy to demonstrate that the proposed project is a minor source with respect to the PSD program. Appendix F of the December 2010 air permit application includes proposed permit conditions that Alpine intends to utilize to quantify emissions and demonstrate compliance. Key monitoring, recordkeeping, and reporting activities include:

- CEMS for monitoring and recording SGC emissions of NO_X, CO, and SO_2
- Opacity Monitoring System (COMS) for the measurement of opacity from the SGC exhaust
- Monitor and record the type and amount of each fuel combusted in the SGC
- Devices to continuously monitor and record hydrated lime, ammonia, and activated carbon injection rates into the SGC and associated control devices
- Temperature sensors to continuously monitor and record combustion zone temperature and exhaust gas temperature
- Devices to monitor and record pressure drop across each baghouse associated with the material handling operations
- Daily visible emissions inspections for each baghouse

- Monitor and record the amount of ultra low sulfur No. 2 fuel oil combusted in each ancillary combustion unit
- Fuel throughput limit for the Auxiliary Boiler
- Hourly operation limits for the Black Start Generator and Emergency Firewater Pump
- Estimate facility-wide emissions of NO_X, CO, SO_2, PM_{10}, $PM_{2.5}$, VOC, Total HAP, and HCl on a monthly basis
- Notify DPNR in the event that monthly emissions of NO_X, CO, SO_2, PM_{10}, $PM_{2.5}$, or VOC exceed 8.33 tons per month; Total HAP emissions exceed 2.08 tons per month; or HCl emissions exceed 0.83 tons per month
- Semiannual compliance reports submitted to DPNR

Please refer to Appendix F of the application for a complete list of monitoring, recordkeeping, and reporting activities. Alpine believes that these proposed monitoring and recordkeeping provisions adequately demonstrate the facility's ability to maintain emissions below the 100 tpy applicability threshold.

* * *

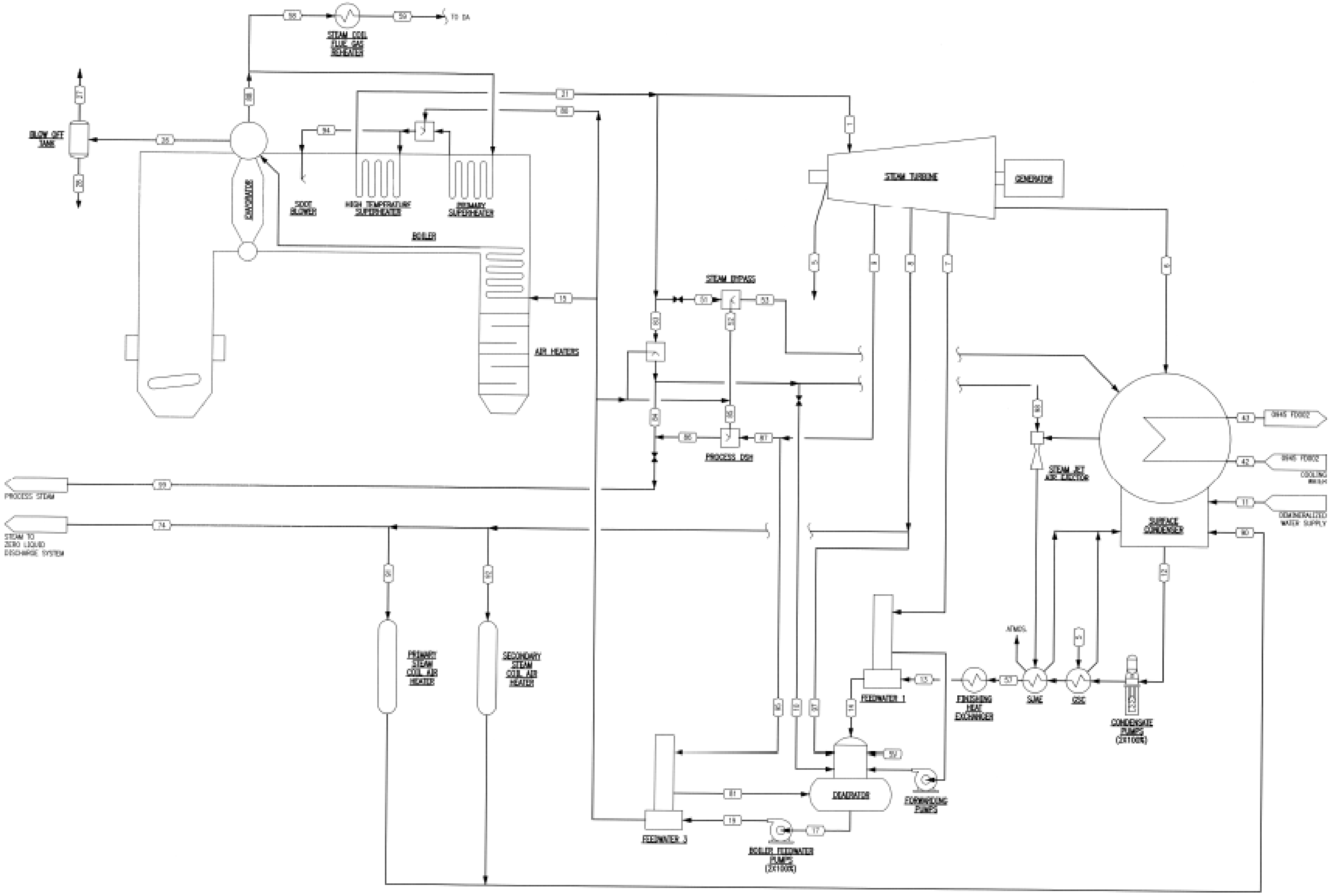
We look forward to your review of our revised application, modeling protocol/significance results, and additional information provided in this letter. If you have any questions about this submittal or require additional information, please feel free to contact me at (303) 789-6915 or Ms. Melissa Dakas of Trinity Consultants at (512) 514-6658. Thank you for your attention to this matter.

Sincerely,
Alpine Energy Group, LLC

Andy Hixson,
VP Environmental & Permitting

Cc: Verline Marcellin (USVI DPNR)
Melissa Dakas (Trinity Consultants)

Attachment 1 – Preliminary Material & Energy Balance


TO DA
STEAM COIL FLUE GAS REHEATER
BLOW OFF TANK
EVAPORATOR
SOOT BLOWER
HIGH TEMPERATURE SUPERHEATER
PRIMARY SUPERHEATER
BOILER
AIR HEATERS
STEAM TURBINE
GENERATOR
STEAM BYPASS
PROCESS DSH
STEAM JET AIR EJECTOR
SURFACE CONDENSER
COOLING WATER
DEMINERALIZED WATER SUPPLY
PROCESS STEAM
STEAM TO ZERO LIQUID DISCHARGE SYSTEM
PRIMARY STEAM COIL AIR HEATER
SECONDARY STEAM COIL AIR HEATER
FEEDWATER 1
FEEDWATER 3
DEAERATOR
FORWARDING PUMPS
BOILER FEEDWATER PUMPS (2X100%)
FINISHING HEAT EXCHANGER
SJAE
GSC
ATMOS.
CONDENSATE PUMPS (2X100%)
43
42
11
90
17
19
81
74
99

Preliminary Material and Energy Balance Data

Stream	*1*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*	*17*
Flow (lb/hr)	220,573	770	172,941	6,918	15,399	24,556	0	14,168	188,322	188,322	188,325	229,021	231,150
Pressure (psia)	1,150	1,150	1	16	42	154	165	15	1	125	125	1,369	42
Temperature (°F)	831	831	106	215	270	421	366	77	104	179	212	355	270
Enthalpy (Btu/lb)	1,401	1,401	970	1,080	1,138	1,230	1,196	45	72	147	180	329	239

Stream	*19*	*21*	*26*	*27*	*28*	*42*	*43*	*51*	*52*	*53*	*57*	*58*	*59*
Flow (lb/hr)	231,150	220,940	2,268	939	1,328	10,232,930	10,232,930	0	0	0	188,322	5,198	5,198
Pressure (psia)	1,369	1,186	1,279	15	15	44	34	1,150	125	100	125	1,279	1,279
Temperature (°F)	273	835	575	213	213	85	101	831	105	744	112	575	575
Enthalpy (Btu/lb)	245	1,402	583	1,151	181	53	69	1,401	73	1,401	80	1,181	583

Stream	*74*	*80*	*81*	*82*	*84*	*85*	*86*	*87*	*88*	*90*	*91*	*92*	*94*
Flow (lb/hr)	4,900	1,882	20,210	4,900	0	154	4,500	4,346	226,756	0	0	0	2,500
Pressure (psia)	42	1,369	154	42	165	1,369	145	154	1,279	42	42	42	1,232
Temperature (°F)	270	355	288	270	366	355	366	421	575	270	270	270	748
Enthalpy (Btu/lb)	1,138	329	257	1,138	1,196	329	1,200	1,230	1,181	1,171	1,138	1,138	1,343

Stream	*95*	*97*	*98*	*99*									
Flow (lb/hr)	20,210	10,499	444	4,500									
Pressure (psia)	154	42	165	145									
Temperature (°F)	421	270	366	366									
Enthalpy (Btu/lb)	1,230	1,138	1,196	1,200									

Dry Bulb Temperature	80.2°F	Gross Electric Power	23,832 kW	Fuel Higher Heating Value	7,500 Btu/lb
West Bulb Temperature	75.0°F	Parasitic Power	3,510 kW	Fuel Lower Heating Value	6,941 Btu/lb
Relative Humidity	78.9%	Net Electric Power	20,322 kW	Fuel Consumption	300.0 MMBtu/hr
Barametric Pressure	14.66 psia			Net Electric Heat Rate	14,763 Btu/kW-hr
Make-up Water Temperature	77.0°F				

Notes

Power Factor at Generator	0.90
Frequency	60.0 Hz
HRSG Blowdown	1.0%

Attachment 2 – Emission Calculations

TABLE B1a: Facility-wide Short-term (Hourly) Emission Summary

EU ID	EU Description	Total PM (lb/hr)	Total PM_{10} (lb/hr)	Total $PM_{2.5}$ (lb/hr)	NO_X (lb/hr)	SO_2 (lb/hr)	CO (lb/hr)	VOC (lb/hr)
EU 02	SGC Unit	8.70	8.70	4.50	19.50	10.50	24.00	15.00
EU 04	Auxiliary Boiler	0.59	0.18	0.04	2.50	0.04	0.98	0.13
EU 05	Black Start Generator	0.16	0.16	0.16	5.91	0.03	1.71	1.18
EU 06	Firewater Pump	0.66	0.66	0.66	1.88	0.00	1.72	0.10
EU 07	Material Handling - Dust Collectors	0.81	0.81	0.81	--	--	--	--
EU 08	Material Handling - Drop Points	0.02	0.01	1.52E-03	--	--	--	--
EU 09	Cooling Tower	0.53	0.21	0.03	--	--	--	--
EU 10	Storage Tanks	--	--	--	--	--	--	0.00
	Fugitives - Vehicle Traffic	0.67	0.13	0.02	--	--	--	--
Total		***12.14***	***10.86***	***6.22***	***29.80***	***10.57***	***28.41***	***16.41***

TABLE B1b: Facility-wide Long-term (Annual) Emission Summary

EU ID	EU Description	Total PM (tpy)	Total PM_{10} (tpy)	Total $PM_{2.5}$ (tpy)	NO_X (tpy)	SO_2 (tpy)	CO (tpy)	VOC (tpy)
EU 02	SGC Unit	33.15	33.15	17.15	74.31	40.01	91.45	57.16
EU 04	Auxiliary Boiler	1.18	0.36	0.09	5.00	0.08	1.95	0.25
EU 05	Black Start Generator	0.04	0.04	0.04	1.48	0.008	0.43	0.30
EU 06	Firewater Pump	0.03	0.03	0.03	0.09	0.00	0.09	0.00
EU 07	Material Handling - Dust Collectors	3.57	3.57	3.57	--	--	--	--
EU 08	Material Handling - Drop Points	0.02	0.01	1.72E-03	--	--	--	--
EU 09	Cooling Tower	2.33	0.93	0.12	--	--	--	--
EU 10	Storage Tanks	--	--	--	--	--	--	0.03
	Fugitives - Vehicle Traffic	2.92	0.57	0.09	--	--	--	--
Total		***43.25***	***38.66***	***21.08***	***80.88***	***40.10***	***93.92***	***57.74***

Table B2a: SGC Unit - Emission Inputs

Input	Value	Units
100% Capacity	2,628,000	MMBtu/yr
Hourly Heat Input Rating:	300	MMBtu/hr
Max Annual Heat Input	2,286,360	MMBtu/yr
Maximum RDF Hourly Usages:	20.0	tons/hr
Estimated 100% RDF Annual Usages:	152,424	tpy
Max RDF Heat Input	2,286,360	MMBtu/yr
Maximum TDF Hourly Usages:	15	MMBtu/hr
Maximum TDF Annual Usages:	114,318	MMBtu/yr
Max TDF Heat Input	114,318	MMBtu/yr
Maximum Wood Residue Hourly Usages:	300	MMBtu/hr
Maximum Wood Residue Annual Usages:	571,590	MMBtu/yr
Max Wood Heat Input	571,590	MMBtu/yr
Molar Gas Volume:	385	scf/lb_{mol}
Wood Burning Control efficiency	80%	%
Metal WastAway Control Efficiency	98%	%
VOC WastAway Control Efficiency	90%	%

Table B2b: SGC Unit - Main Emissions

Pollutant	Emission Factor	Emission Factor Units	HAP (Yes/ No)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	ppmvd
CO	0.080	lb/MMBtu	No	24.00	91.45	91
NO_X	0.065	lb/MMBtu	No	19.50	74.31	45
VOC	0.050	lb/MMBtu	No	15.00	57.16	36
PM Filterable	0.019	lb/MMBtu	No	5.70	21.72	-
PM Condensable	0.010	lb/MMBtu	No	3.00	11.43	-
PM Total	0.029	lb/MMBtu	No	8.70	33.15	-
PM_{10} Filterable	0.019	lb/MMBtu	No	5.70	21.72	-
PM_{10} Total	0.029	lb/MMBtu	No	8.70	33.15	-
$PM_{2.5}$ Filterable	0.009	lb/MMBtu	No	2.58	9.83	-
$PM_{2.5}$ Total	0.015	lb/MMBtu	No	4.50	17.15	-
SO_2	0.0350	lb/MMBtu	No	10.50	40.01	17

Table B4: Auxiliary Boiler Emission Calculations

Boiler Information

Heat Input Capacity	25	MMBtu/hr
Hours of Operation per Year	4,000	hrs/yr
Potential Throughput	714.29	kgals/yr
S = Weight % Sulfur	0.0015	%

Auxiliary Boiler Emissions

Pollutant	Emission Factors	Emission Factor Units	Emissions (lb/hr)	Emissions (tpy)
NO_x	14.00	lb/kgal	2.50	5.00
CO	5.46	lb/kgal	0.98	1.95
VOC	0.70	lb/kgal	0.13	0.25
PM	3.30	lb/kgal	0.59	1.18
PM_{10}	1.00	lb/kgal	0.18	0.36
$PM_{2.5}$	0.25	lb/kgal	0.04	0.09
SO_2	0.21	lb/kgal	0.04	0.08

Methodology

1 gallon of No. 2 Fuel Oil has a heating value of 140,000 Btu.

Potential Throughput (kgals/year) = Heat Input Capacity (MMBtu/hr) x 4,000 hrs/yr x 1kgal per 1,000 gallon x 1 gal per 0.140 MMBtu

NOx Emission Factors are from a vendor guarantee to meet BACT.

SO_2 Emission Factor are from AP 42, Table 1.3-1 (SCC 1-02-005-01/02/03) Supplement E 9/98 (see erata file).

CO and VOC Emission Factors are from general industry data; recent vendor quotes indicate that these factors are more conservative than AP-42 factors.

PM, PM_{10} and $PM_{2.5}$ Emission Factors are from AP-42, Table 1.3-2 and 1.3-6 (SCC 1-02-005-01/02/03). PM factor indicates Total PM (filterable + condensable).

Emission (tons/yr) = Throughput (kgals/ yr) x Emission Factor (lb/kgal)/2,000 lb/ton

SO_2 (lb/kgal) = 142 x Sulfur content (%) per AP-42, Table 1.3-1.

TABLE B5: Black-Start Generator Emission Calculations

Engine Information

Quantity	1	
Size (each)	2,000	kW
Size (each)	2682	hp
Heat Input (each)	20.00	MMBtu/hr
Hours of Operation (each)	500	hours

Black-Start Generator Emissions

Pollutant	Emission Factors[1, 2]	Emission Factor Units	Emissions per Engine (lb/hr)	Emissions per Engine (tpy)	Total Emissions (lb/hr)	Total Emissions (tpy)[3]
NO_x	1	g/hp-hr	5.91	1.48	5.91	1.48
CO	6.39E-04	lb/hp-hr	1.71	0.43	1.71	0.43
VOC	0.2	g/hp-hr	1.18	0.30	1.18	0.30
PM/ PM_{10}	7.90E-03	lb/MMBtu	0.16	0.04	0.16	0.04
$PM_{2.5}$	7.90E-03	lb/MMBtu	0.16	0.04	0.16	0.04
SO_2	1.21E-05	lb/hp-hr	0.03	0.008	0.03	0.008

1. Emission factor for SO_2 from AP-42 Chapter 3.4 Table 3.4-1, "Emission Factors for Large Stationary Diesel And All Stationary Dual-fuel Engines" (October 1996). SO_2 emissions based on 15 ppm sulfur content in fuel.

2. Emission factors for NO_X, CO, VOC, PM, and PM_{10} are based on manufacturer provided information.
Conservatively, total HC emission factor is used for VOC and PM/ PM_{10} emission factor used for $PM_{2.5}$.

3. Estimated maximum use of each diesel generator engine is 500 hours per year per generator.

TABLE B6: Firewater Pump Emission Calculations

Engine Information

Quantity	1	
Size	300	hp
Heat Input	2.5	MMBtu/hr
Hours of Operation	100	hours

Fire Pump Engine Emissions

Pollutant	Emission Factors[1, 2, 4, 5] (lb/hp-hr)	Emissions (lb/hr)	(tpy)[3]
NO_X	6.28E-03	1.88	0.09
CO	5.73E-03	1.72	0.09
VOC	3.31E-04	0.10	0.00
PM/ PM_{10}	2.20E-03	0.66	0.03
$PM_{2.5}$	2.20E-03	0.66	0.03
SO_2	1.21E-05	3.64E-03	1.82E-04

1. Emission factor for SO_2 from AP-42 Chapter 3.3 Table 3.3-1, "Emission Factors for Uncontrolled Gasoline & Diesel Industrial Engines" (October 1996).

2. Emission factors for NO_X, CO, and VOC based on EPA Tier 3 Diesel Engine Emission Standards. The Tier 3 emission standards are 3.0 g/bhp-hr for NMHC + $NO_{X,}$ 2.6 g/bhp-hr for CO, and 0.15 g/bhp-hr for PM. To split the NMHC + NO_X limit into separate emission factors for NMHC (VOC) and NO_X, the combined emission factor is scaled by the ratio of 95% NOx and 5% VOC.

3. Estimated maximum use of the fire pump engine is 100 hours per year.

4. Emission Factor for PM_{10} is from AP-42 Section 3.3, Table 3.3.1, "Emission Factors for Uncontrolled gasoline and Diesel Industrial Engines" (October 1996). Assume that PM_{10} is equal to $PM_{2.5}$.

Table B7: Particulate Matter Emissions from Dust Collectors:

Source ID	Description	Discharge Volume (dscfm)	Grain Loading (gr/dscf)	$PM / PM_{10} / PM_{2.5}$ Emission Rate (lb/hr)	(tpy)
DC_1	Material Storage Unloading Dust Collector	2,500	0.005	0.11	0.47
DC_2	Material Storage Dust Collector A	7,000	0.005	0.30	1.31
DC_3	Material Storage Dust Collector B	7,000	0.005	0.30	1.31
DC_7	Hydrated Lime Building Dust Collector	2,500	0.005	0.11	0.47
			Total	**0.81**	**3.57**

Methodology

Emission Rate (lb/hr) = Discharge Volume (dscfm) × 60 min/hr × Grain Loading (gr/dscf) ÷ 7000 (gr/lb)

Emission Rate (tpy) = (lb/hr) × 8760 (hr/ year) ÷ 2000 (lb/ton)

Since only small particles are expected to escape the baghouse fabric, all PM emissions are conservatively assumed to be in the $PM_{2.5}$ and PM_{10} size range.

TABLE B8: Material Handling - Drop Point and Conveyor Emission Calculations

I. Drop Point Emissions

AP-42, Fifth Edition, Volume I, Section 13.2.4, Aggregate Handling and Storage Piles states: (Equation 1)

$$E = k(0.0032)\frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}\,(lb/ton)$$

E: Emission Factor
k: Particle Size Multiplier (0.74 for PM, 0.35 for PM_{10}, and 0.053 for $PM_{2.5}$)
U: Mean Wind Speed, (mph) = 10.40 (From 2008 MCHAV3 Weather Data)
M: Material Moisture Content (%)

Material	M (%)	Drop Point Emission Factors PM (lb/ton)	PM_{10} (lb/ton)	$PM_{2.5}$ (lb/ton)
Limestone	4	2.32E-03	1.10E-03	1.67E-04
RDF	12	4.99E-04	2.36E-04	3.58E-05

Source Name	Drop Point	Control * (%)	Max Hourly Throughput (tph)	Max Annual Throughput (tpy)	PM Hourly Emissions (lb/hr)	PM Annual Emissions (tpy)	PM_{10} Hourly Emissions (lb/hr)	PM_{10} Annual Emissions (tpy)	$PM_{2.5}$ Hourly Emissions (lb/hr)	$PM_{2.5}$ Annual Emissions (tpy)
DP 1	Fuel Drop	80	40	152,424	4.00E-03	7.61E-03	1.89E-03	3.60E-03	2.86E-04	5.45E-04
DP 2	Limestone Drop	80	20	5,000	9.30E-03	1.16E-03	4.40E-03	5.50E-04	6.66E-04	8.33E-05
DP 3	Metering Bin Drop	80	40	152,424	4.00E-03	7.61E-03	1.89E-03	3.60E-03	2.86E-04	5.45E-04
DP 4	Metering Bin Drop (2)	80	40	152,424	4.00E-03	7.61E-03	1.89E-03	3.60E-03	2.86E-04	5.45E-04
				Total	**0.021**	**0.024**	**0.010**	**0.011**	**0.002**	**0.002**

* Control factor of 80% is used for telescoping chute.

TABLE B9: Cooling Tower Emission Calculations

Source Description	Tower Flow Capacity (gpm)	Drift Loss (gal drift/ gal flow) [2]	Drift Loss (gal/hr)	Total Uncontrolled Liquid Drift Loss (lb drift/hr)	TDS Content (ppm)	PM Emission [1] (lb/hr)	PM_{10} [3] Emissions (lb/hr)	$PM_{2.5}$ [3] Emissions (lb/hr)	Operating Schedule (hrs/yr)	PM Emissions (tpy)	PM_{10} [3] Emissions (tpy)	$PM_{2.5}$ [3] Emissions (tpy)
Cooling Tower Cell 1	8,870	0.000015	8.0	66.6	4,000	0.27	0.11	0.01	8,760	1.17	0.47	0.06
Cooling Tower Cell 2	8,870	0.000015	8.0	66.6	4,000	0.27	0.11	0.01	8,760	1.17	0.47	0.06
					Total (tpy)	**0.53**	**0.21**	**0.03**		**2.33**	**0.93**	**0.12**

Notes

1. PM Emission Factor, lbs PM/hr = (TDS Content, ppm) / (1 x 10^6) x (Total Liquid Drift Loss, lbs drift/hr); TDS content factor based on Chapter 13.4 of AP-42. 1/95.
2. Each cell will be equipped with a drift eliminators to control drift to less than 0.0015% (Drift Loss Factor).
3. PM_{10} and PM2.5 emissions are conservatively presumed at of potential drift PM emissions, based on the paper *Calculating Realistic PM10 Emissions from Cooling Towers* , by Joel Reisman and Gordon Frisbie, 2000.
   PM10 are assumed at 40% of the PM emissions and PM2.5 are assumed at 5% of the total PM emissions

TABLE B10: Paved Roadway Fugitives from Truck Traffic

Emission Factors (Equation 2 of AP-42, Section 13.2.1.3, Predictive Emission Factor Equations (Revised November 2006)

$$\boxed{E = \left[k\left(\frac{sL}{2}\right)^{0.65}\left(\frac{W}{3}\right)^{1.5} - C\right]\left(1-\frac{P}{4N}\right)(lb/VMT)}$$

Nomenclature:

	PM	**PM$_{10}$**	**PM$_{2.5}$**	
E:	See Below	See Below	See Below	Calculated Emission Factor (lb/VMT)
k:	0.082	0.016	0.0024	Particle size multiplier from AP-42 Table 13.2.1-1.
C:	0.00047	0.00047	0.00036	Emission factor for Exhaust, Brake Wear and Tire Wear (lb/VMT) from AP-42 Table 13.2.1-2.
P:	171	171	171	Annual average number of days with measureable precipitation from Southeast Regional Climate Center, Charlotte Amalie Met station (http://www.sercc.net/cgi-bin/sercc/cliMAIN.pl?vi8905)
N:	365	365	365	Number of days per year
W:	18.55			Mean vehicle weight (tons) - see Estimated Truck Traffic table below
sL:	7.4	7.4	7.4	Mean surface silt loading (g/m^2) from AP-42 Table 13.2.1-4, [Value used for Solid Municipal Landfill as a conservative value for the site]
VMT:	6	VMT/day		(see Estimated Truck Traffic table below)
	2,245	VMT/year		(see Estimated Truck Traffic table below)

VMT Calculations (Estimated Truck Traffic)

Material Being Transported	**Miles per Segment (mi/trip)**	**Trips Per Day [1]**	**Trips Per year [1]**	**Average Truck Weight (tons)**
MSW Trucks	0.13	36	13140	20.0
Diesel Truck	0.24	0.72	264	16.5
Activated Carbon Truck	0.28	0.04	13	10.0
Limestone Truck	0.28	2.74	1000	10.0
Ammonia Truck	0.38	0.11	41	10.0
Ash Truck	0.06	7	2409	20.0

[1] Based on engineering design estimates of maximum annual material usage and production rates.

Paved Roadway Potential Emissions

	Emission Factor			**Daily Emission Rates**			**Potential Annual Emission Rates**		
Road Type	**PM (lb/VMT)**	**PM$_{10}$ (lb/VMT)**	**PM$_{2.5}$ (lb/VMT)**	**PM (lb/day)**	**PM$_{10}$ (lb/day)**	**PM$_{2.5}$ (lb/day)**	**PM (tpy)**	**PM$_{10}$ (tpy)**	**PM$_{2.5}$ (tpy)**
Paved Road	2.61	0.51	0.08	16.02	3.12	0.47	2.92	0.57	0.09

Fugitive road dust emissions will be minimized through best management practices, e.g., watering/chemical dust suppression.

AEG Anguilla Power, LLC - St. Croix, USVI
Air Emission Calculations

TABLE B11: Storage Tank Emission Calculations

Parameter	**Ammonia Storage Tank**	**Fuel Oil Storage Tank**
ID(s)	T1-1	T2-1
Number(s) of Tanks	1	1
Tank Type	Horizontal Tank	Vertical Fixed Roof
Shell Height or Length (ft) [1]	47	25
Shell Diameter (ft) [1]	11	30
Maximum Liquid Height (ft)	N/A	25
Average Liquid Height (ft)	N/A	13
No. of Turnovers per Year [2]	10.00	6
Maximum Working Tank Volume (ft^3)	N/A	17,671
Maximum Working Tank Volume (gal)	30,000	132,183
Maximum Annual Throughput (gal/yr) [1]	300,000	793,095
Heated (Y/N) [1]	N	N
Underground (Y/N) [1]	N	N
Shell/ Roof Color [1]	White	White
Shell/ Roof Condition [1]	Good	Good
Roof Type	N/A	Dome
Roof Height (ft) [3]	N/A	0.00
Roof Radius (ft) (Dome Roof) [3]	N/A	30
Vacuum Setting (psig) [3]	-0.03	-0.03
Pressure Setting (psig) [3]	0.03	0.03
Tank Contents (used in TANKS)	Ammonia	Distillate Fuel No. 2
Individual Tank Emissions (lb/yr) [4]	1592.33	62.76
Emissions (tpy)	**0.80**	**0.03**

[1] Based engineering design estimates.

[2] Maximum Annual Throughput (gal/yr) = No. of Turnovers per Year * Maximum Working Tank Volume (gal)

[3] Default values obtained from U.S. EPA TANKS 4.09d.

[4] Results from TANKS 4.0.9.d runs.

TABLE D1: GHG Emission Calculations

Steam Generating Combustor :

Maximum Heat Input Rating: 300 MMBtu/hr
Estimated Annual Heat Input: 2,260,080 MMBtu/yr
Maximum RDF (MSW) Annual Usage: 150,672 Short tpy
RDF High Heat Value (HHV)[1]: 7,500 Btu/lb = 15.00 MMBtu/short ton
Carbon Content (CC)[2]: 0.398
Biogenic Portion of RDF[3]: 60%

Auxiliary Boiler :

Heat Input Capacity: 25 MMBtu/hr
Hours of Operation per Year: 4,000 hrs/yr
Potential Throughput[4]: 714,285.71 gal/yr
No.2 Fuel Oil High Heat Value (HHV)[5]: 0.138 MMBtu/gal

Emission Unit ID	Description	Fuel Type	Tier Used	Pollutant	Emission Factor	Emission Factor Units	Emission Factor Source	Annual Emissions (metric tons)[6,7,8]
EU 02	SGC	RDF (MSW)	Tier III	CO_2	See Note 8			200,091.41
				CH_4	0.032	kg CH_4/MMBtu	40 CFR Part 98, Subpart C, Table C-2	72.32
				N_2O	0.0042	kg N_2O/MMBtu	40 CFR Part 98, Subpart C, Table C-2	9.49
EU 04	Auxiliary Boiler	No.2 Fuel Oil	Tier I	CO_2	73.960	kg CO_2/MMBtu	40 CFR Part 98, Subpart C, Table C-1	7,290.34
				CH_4	0.003	kg CH_4/MMBtu	40 CFR Part 98, Subpart C, Table C-2	0.30
				N_2O	0.0006	kg N_2O/MMBtu	40 CFR Part 98, Subpart C, Table C-2	0.06
							Total CO_2 Emissions	207,381.75
							Total CH_4 Emissions	72.62
							Total N_2O Emissions	9.55
							Total CO_2e Emissions[9]	**211,867.70**
							Landfill CO_2e Reduction	**144,918.12**
							Biogenic CO_2 from RDF	**120,054.85**
							Net CO_2e Emissions	**-53,105.27**

Notes:

1. High heating value for Fluff estimated based on analysis of MSW and WastAway process.
2. Carbon content for Fluff obtained from the analysis of MSW and WastAway process.
3. Biogenic portion of MSW based on information developed by EIA, http://www.eia.doe.gov/cneaf/solar.renewables/page/mswaste/msw_report.html
4. 1 gallon of No. 2 Fuel Oil has a heating value of 140,000 Btu.
5. High heating value for No.2 Fuel Oil obtained from 40 CFR Part 98, Subpart C, Table C-1.
6. CO_2 emissions from No.2 Fuel Oil combustion calculated per Equ. C-1 and Tier I methodology provided in 40 CFR Part 98, Subpart C.
7. CO_2 emissions from MSW combustion calculated per Equ. C-3 and Tier III methodology provided in 40 CFR Part 98, Subpart C.
8. CH_4 and N_2O emissions from Fluff, and No.2 Fuel Oil combustion calculated per Equ. C-8 provided in 40 CFR Part 98, Subpart C.
9. Total CO_2e emissions calculated based on the following Global Warming Potentials obtained from Table A-1 provided in 40 CFR Part 98, Subpart A:

CO_2	1
CH_4	21
N_2O	310

Attachment 3 – 2009 NAWTEC Paper – WTE SCR Usage in Europe

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IS DE-NOX BY SCR TO BE THE FUTURE IN US? – TECHNOLOGY AND TENDENCIES WITHIN APC-EQUIPMENT

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ABSTRACT

The paper will present available De-NO_x technologies as well as the paper will present the operational experience in European countries where the technology has been operating for approx. 10-15 years. The experience is based on Ramboll's experience with NO_x control on advanced WtE plants in Europe.

Technical SCR solutions will be discussed and specific technical obstacles and specific precautions to be taken will be highlighted and illustrated by showcases.

Investment and operating costs for SNCR versus SCR will be presented.

Finally it will be evaluated which effect De-NO_x at WtE facilities will have compared to the energy sector in general.

INTRODUCTION

The air emission limits have over the years been tightened both in Europe and in North America. Still more efforts are given by the European Union and the US EPA to implement stricter emission limits as well as WtE facilities are implementing more efficient technology in order to get a better public acceptance and to reduce the emission of pollutants.

NO_x emission has become a global problem and "hot-spots" have been identified in certain areas of US, Europe and Asia as illustrated in Figure 1.

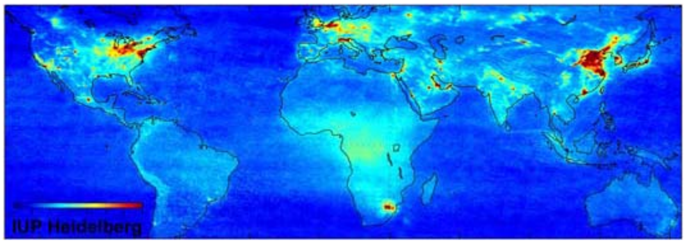


Figure1. NO_x Hot Spot. Source. IUP Heidelberg, Institut für Umweltphysik

This has resulted in the fact that the NO_x emission limit for WtE facilities in US has been heavily tightened and recently new WtE facilities have to deal with emission limits less than 50% of the EPA emission limits.

The WtE facilities have to take into consideration the cost for investment and the cost for operating more and more efficient De-NO_x.

Until recently WtE facilities in USA have been equipped with the Selective-Non-Catalytic-Reduction (SNCR) technology to comply with the regulatory requirements - will it also be the way forward or will the regulatory requirements be so strict that Selective-Catalytic-Reduction (SCR) technology will be required for future plants?

EMISSION STANDARDS FOR WTE FACILITIES

Waste incineration produces flue gas that contains a spectrum of components (e.g. dust, acidic compounds, heavy metals, and dioxins). To avoid emission of these pollutants to the surroundings, extensive flue gas treatment (FGT) is necessary before discharge to the air reducing the level below other energy producing facilities.

Table 1 below shows the typical raw gas concentration of pollutants in flue gas before the air pollution control equipment. The raw flue gas data are based on a WTE facility receiving mixed MSW (60-70%) and industrial waste similar to MSW (30-40%). To compare the raw flue gas data with the cleaned flue gas the emission limits in the European Union (EU) is shown. The EU limits (EU Directive 2000/76/EF on Waste Incineration) are more or less similar to the recent US EPA regulation (MACT).

	Component	Unit (11% O_2)	Raw flue gas quality (typical values, daily average)	Raw flue gas quality (typical values, ½ hour average	EU emissions requirements
	TSP / Dust	mg/Nm^3	2000	5000	10
Acidic compounds	SO_2	mg/Nm^3	400	600	50
	NO_x[1]	mg/Nm^3	400	600	200
	HCl	mg/Nm^3	600	2000	10
	HF	mg/Nm^3	10	50	1
Heavy metal	Hg	mg/Nm^3	0.5	1.5	0.5
	Cd	mg/Nm^3	1	5	N.D.
	Cd, Tl	mg/Nm^3	1	5	0.05
	Pb	mg/Nm^3	20	30	N.D.
	∑ As, Ni, Co Pb, Cr, Cu, V, Mn, Sb	mg/Nm^3	10	50	0.5
	Dioxins	ng TEQ/Nm^3	2	5	0.1

1) Some European countries has reduced the limit to 70/80 mg/Nm3

Table 1: Typical pollutant concentration in raw gas and emission limits (EU Directive 2000/76/EF on Waste Incineration)

The emission limit for NO_x at 200 mg/Nm^3 has been in force for new European plants from the year 2000 and for existing plants from the end of 2005.

In some European countries a lower emission limit has been introduced. In Austria and Switzerland the NO_x limit is restricted at 80 mg/Nm^3 and in the Netherland the NO_x limit is limited at 70 mg/Nm^3.

In other European countries like Sweden a tax incentive has been introduced enforcing the WtE plants to operate with very low NO_x-emission at around 20-50 mg/Nm^3.

A new European Industrial Air Act is under preparation and stricter air emission levels are being proposed and the NO_x emission limit is most likely to be tightened.

DE-NO$_X$ METHODS

The air pollution control (APC) system consists of a number different treatment steps for the different types of air pollutants. There is no universal method to select the best flue gas system for a given facility, since it depends on required guaranteed emission values, size of the plant, fee on pollutant emission, requirement of plume visibility from stack etc.

As the APC system in the US is dry or semi-dry I will concentrate only on these systems and do not in the following consider the precautions to take if the De-NOx system is combined with wet flue gas treatment.

In dry and semidry APC-systems the flue gas is brought to react with lime in a reactor and the dust is collected in a bag house. filter. The process is illustrated in Figure 2.

The DeNOx process could be a SNCR or a SCR process as illustrated in Figure 2. The SNCR process will always take place in the boiler part. The SCR can be located in various locations, in figure 2 the tail-end solution (the most common solution) is shown.

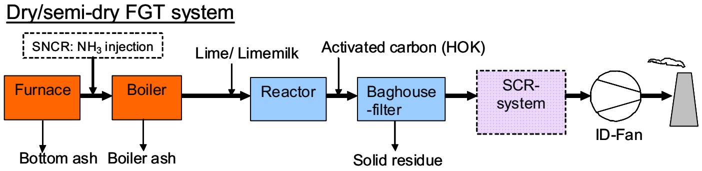


Figure 2. Illustration of dry/semi-dry FGT system and SNCR or SCR DeNOx reduction

For waste incineration facility the general flue gas concentration is around 400 mg/Nm^3 (daily average). However, modern WtE facilities with an advanced automatic combustion control (ACC) system, which all the major WtE manufacturers supply, are normally capable of reducing the NO_x level to 250 mg/Nm^3 as well as recirculation of flue gas can result in lower NO_x emission. Still active NO_x removal is required to achieve NO_x levels below or under the emission limit.

The two most common methods are;

- Selective Non Catalytic Reduction (SNCR)
- Selective Catalytic Reduction (SCR)

In both cases ammonia (NH_3) or urea ($(NH_2)_2CO$) is added in a water suspension.

$$4\ NO + 4\ NH_3\ O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

The stoichiometric consumption of ammonia is 1,5 kg 25% NH_3 per kg NO_x (as NO_2) reduced.

Based on theoretical calculations and operating experience surplus ammonia has to be added to the process to ensure sufficient efficient reaction. The major part of the surplus ammonia is oxidised to N_2, NO or will be used to the reaction with the formed NO. However a smaller part will leave the system as a so-called ammonia-slip.

If urea is used a side reaction takes place producing laughing gas (N_2O).

SNCR

For the SNCR process ammonia is injection into the flue gas in the furnace at the location where the temperature is around 850-900°C. The temperature is important as the optimal reaction between ammonia and NO_x takes place in this temperature span.

Surplus ammonia has to be added to the process for ensuring an effective reduction of NO_x. As an example is it necessary to add approx. 2.5 times the stoichiometric amount of ammonia for reducing the amount of NO_x with 80%.

The process demands a careful control of the ammonia injection as well as the combustion process as the temperature is essential for the DeNOx process as the input (the nozzle) is fixed. Often 3 nozzle layers are required to ensure a sufficient NO_x control.

The consumption is normally 3-4 kg 25% ammonia water per ton (metric) waste by reduction of NO_x from approx. 400 mg/Nm^3 to approx. 180 mg/Nm^3 (55% reduction).

Emission values around 150 – 180 mg NO_x/Nm^3 is commonly used for the SNCR process. Lower values – to around 100 mg/Nm^3 – are possible with the SNCR process but the consumption of ammonia is relative high and the risk for high ammonia slip will increase.

Some European countries restrict the emission ammonia slip, for instance in Austria and Switzerland where the emission of ammonia is restricted to 5 mg/Nm^3. Even if ammonia slip is not restricted by regulation ammonia slip should not be higher than 5-10 mg/Nm^3 as ammonia may cause a light odour of the flue gas residues.

When operating the SNCR process with emission values around 150 mg/Nm^3 the ammonia slip is normally 1-5 mg/Nm^3. If the emission value is required much lower than 150 mg/Nm^3 it is normally not possible to get guarantees on ammonia slip below 10 mg/Nm^3.

The SNCR process is typically chosen on incineration facilities where there is no regulatory or financial incentive to reduce NO_x below emission limits around 150-200 mg/Nm^3.

Except for the injection nozzles, the dosing system and the ammonia storage the SNCR system does not require much space.

SCR

The reaction between NO_x and the injected NH_3 takes place on a catalytic surface. Due to the catalyst the reaction can take place at a lower temperature normally around 250 °C, however, references in the temperature interval between 180-350°C are available.

The acceptable temperature is among other depending on the content of dust, SO_2 and HCl in the flue gas and hereby depending on whether the SCR is placed before or after the flue gas treatment plant – after the flue gas treatment system the temperature can be lower as the content of pollutants is reduced significant.

Contrary to the SNCR process ammonia has to be added to the process in a small surplus only. For reducing the amount of NO_x with 80% some few percent (3-5%) ammonia more than the stoichiometric amount has to be added compared to 2,5 times for the SNCR.

The consumption of ammonia water is below 1,5 kg 25% ammonia water per ton (metric) waste by reduction of NO_x from approx. 400 mg/Nm^3 to approx. 180 mg/Nm^3. The ammonia slip is negliable.

As mentioned above SCR is typically used if there is a regulatory or a financial incentive to reduce the NO_x emission and normally SCR processes are operated with emission levels between 20-70 mg/Nm^3 and in some cases below 20 mg/Nm^3 as is the case at many WtE facilities in Sweden where a high NOx-tax is the driver.

At WtE facilities the SCR process is typically introduced after the flue gas is treated and SO_2 and SO_3 is reduced to prevent precipitation of ammoniahydrogensulphate as well as the lifetime of the catalyst is prolonged when Hg, HCl and dust is removed before the catalyst.

For the tail-end SCR process, where the flue gas has been treated and the amount of pollutants is reduced the process might be carried out at a lower temperature without too high risk for precipitation. Some plants have tested temperature from 180-220°C but the experience is so far not sufficient and Ramboll recommends temperature at around 220-250°C.

A disadvantage with the tail-end SCR process is that the flue gas temperature after the APC system is lower than the temperature required for SCR and a reheating is required. Reheating is normally done by usage of heat exchanger where the ingoing flue gas to the SCR-process is preheated with the flue gas leaving the SCR as illustrated in figure 3. The need for additional heating is hereby reduced to approx. 25 °C which can be done by the usage of drum steam or saturated steam from the turbine.

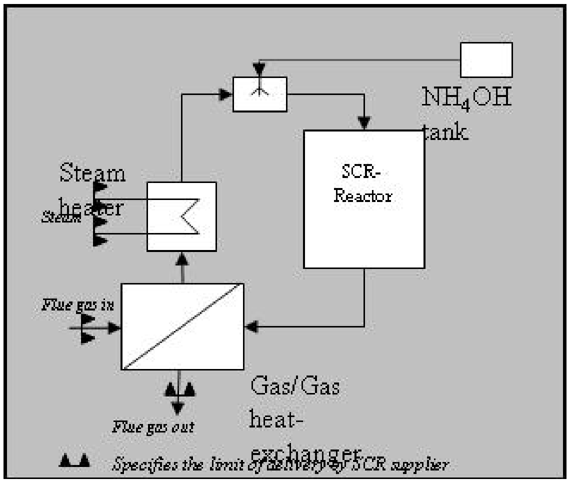


Figure 3. Typical Configuration of the SCR System

Alternatively the SCR process can be placed before the APC plant. However, the risk for clocking is high and Ramboll recommends to place an ESP before the SCR to prevent too high dust concentration to the SCR. Operating experience from the few WtE facilities operating high SCR placed before the APC plant shows that the life-time of the catalyst is reduced significantly.

The SCR system consists of a heat exchanger, a steam re-heat system, the catalyst (SCR) and the ammonia storage and dosing system. The dimensions depend on the actual supplier. Typical dimensions for a 600 tpd facility are given in Table 2.

	Heat-exchanger	Steam re-heat	SCR
Length	8.5 m	6 - 7 m	6 - 7 m
Height	5 m	1 – 1,5 m	12 - 19 m
Width	6 m	4 m	4,5 – 8,5 m

Table 2: Typical dimensions for the SCR-system

The material and the structure of the catalyst shall de designed in cooperation with experienced vendors of the SCR as the design of the SCR is crucial for a good operation and a long lifetime of the system.

The active component is in catalyst is among others V_2O_2.

A wide structure of the catalyst will educe the risk for clocking but contrary a narrow structure of the catalyst will increase the surface of the SCR and hereby increase the efficiency of the SCR.

A typical example of a catalyst is illustrated in figure 4.

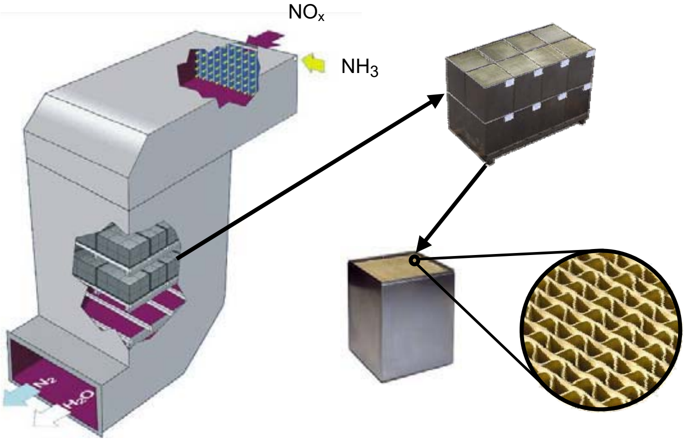


Figure 4. Typical SCR System. Source: Haldor Topsoe

ADVANTAGES AND DISADVANTAGES OF SCR AND SNCR

The advantages and the disadvantages of SCR and SNCR are summarized in the matrix in Figure 5 below.

	SNCR	SCR
Advantages	• Simple technology • Lower investment cost • Many reference plants • Low foot-print	• Low consumption of ammonia • Many reference plants • Emission levels below 100 mg/Nm^3 can easily be achieved • Side effect – dioxin reduction
Disadvantages	• Higher ammonia consumption • Risk for ammonia slip • Difficult to get guarantees from vendors below 100-150 mg NO$_x$/m^3 • Require high control of the temperature	• High investment costs • Energy consumption for reheat • Relative large foot-print

Figure 5: *Matrix illustrating advantages and disadvantages of SCR and SNCR.*

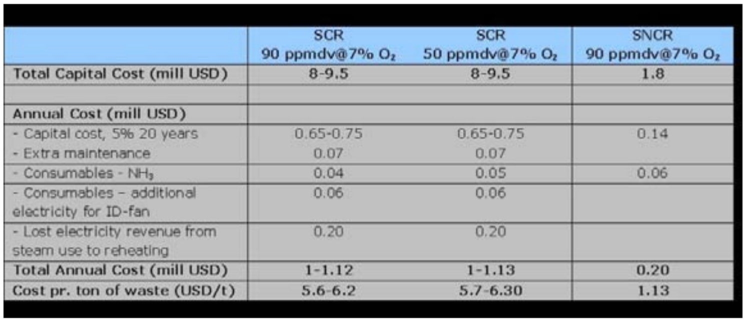
OPERATIONAL AND INVESTMENT COSTS

The investment cost for installation of DeNO$_x$ is significant higher for SCR compared to SNCR. The consumption of ammonia is higher for SNCR compared to SCR, but is catch up by the requirement for re-heat for the SCR (tail-end).

Various set of emission levels have been used for comparing NO_x reduction by SNCR and SCR:

- 150 mg/Nm^3
- 100 mg/Nm^3
- 70 mg/Nm^3 (only guaranteed with SCR, but is included as it is a typical operation level if SCR is installed)

Based on Ramboll's experience the cost – investment of operational – is calculated over a 20 years period and is summarized in Table 3.



	SCR 90 ppmdv@7% O_2	SCR 50 ppmdv@7% O_2	SNCR 90 ppmdv@7% O_2
Total Capital Cost (mill USD)	**8-9.5**	**8-9.5**	**1.8**
Annual Cost (mill USD)			
- Capital cost, 5% 20 years - Extra maintenance	0.65-0.75 0.07	0.65-0.75 0.07	0.14
- Consumables - NH_3	0.04	0.05	0.06
- Consumables – additional electricity for ID-fan	0.06	0.06	
- Lost electricity revenue from steam use to reheating	0.20	0.20	
Total Annual Cost (mill USD)	**1-1.12**	**1-1.13**	**0.20**
Cost pr. ton of waste (USD/t)	**5.6-6.2**	**5.7-6.30**	**1.13**

Table 3. Investment Cost and Operation Cost for SCR and SNCR

As shown in Table 3 the cost per ton of waste is approximately 5-6 USD/ton.

OPERATION EXPERIENCE

$DeNO_x$ processes – both SNCR and SCR - have been used with good experience in Europe for many years.

In Denmark all $DeNO_x$ systems are based on the SNCR technology as the emission limit is 200 mg/Nm^3 and as there is no incentive reducing the emission further.

In Sweden the high NO_x tax make the SCR system feasible and most of the new WtE plants are equipped with SCR systems operated with very low emission levels – often below 20 mg/Nm^3. A very good example is the plant in Malmö, SYSAV, where the plant has operated a SCR system since 2003. Based on the good experience also the new line taken into operation in 2008 is equipped with SCR. The plant is shown in figure 6.

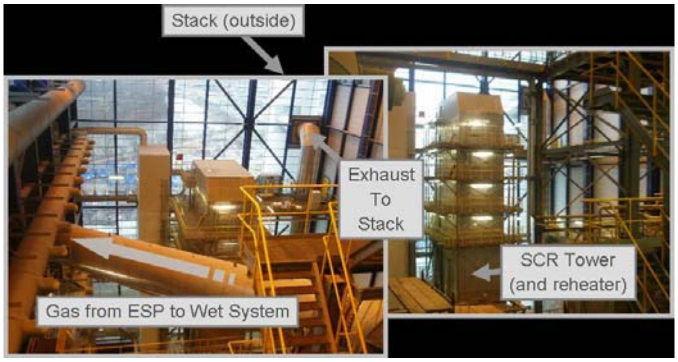


Figure 6. SCR at SYSAV, Malmö in Sweden.

In Norway the regulation can be fulfilled with SNCR. However, a high emission tax has enforced the larger plant to install SCR.

Austrian WtE facilities have to fulfil a low emission level and have had SCR for many years. Especially the plant in Vienna, Spittelau, has had SCR for 17 years. The experience with the catalyst itself is good, however, the design of the preheat-system as well as the possibility for manual inspection and cleaning of the catalyst is not optimal. For new SCR-systems these problems have been mended and new installations operate satisfactory.

In Germany the emission limit for NO_x has been introduced by the national regulation before the EU-regulation was implemented. Most of the German plants are equipped with SCR and have a long-time experience with SCR. Most of the SCR plants operate without problems, however, some of the older plants realize problems mainly due to clocking problems. For new facilities the experience is satisfactory as the design and the reliability of the SCR has been increased significantly. Some German plants have tested the high temperature-high dust solution and have experienced clocking problems.

In Italy most of the plants are running SNCR processes. Especially ASM Brescia has experienced good operation and very low emission levels with SNCR. However, the Italian regulation is becoming more stringent especially in the northern part of Italy and ASM Brescia is testing a high temperature-high dust solution at one of their three lines wit hthe purpose of achieving even lower NO_x values and reducing the ammoniaslip. The preliminary results show acceptable operation but reduced lifetime of the catalyst.

Most of the WtE facilities in Switzerland is equipped with SCR and have experienced good operation. The SCR is commonly a tail-end solution but also good experience from operation of a high temperature-low dust SCR solution.

In France and Belgium both SNCR and SCR processes are installed, both solutions are operating without problems.

In the Netherlands most WtE facilities – and all new facilities - are equipped with SCR due to the low emission limit.

To sum up it can be concluded that the experience with both SNCR and SCR is extensive and the operation with both systems are good. Some of the old SCR installations have experienced problems mainly due to insufficient experience in the design and cleaning and inspection is difficult. Also clocking and poisoning of the catalyst have created problems for the old plants, for the more recent plants the quality of the catalyst material and a better knowledge of the chemical reaction and the temperature have improved the operation significant and the SCR is today in Europe considered a well-proven and stable process.

WILL SCR INSTEAD OF SNCR SIGNIFICANTLY REDUCE THE OVERALL NO_X EMISSION FROM THE POWER INDUSTRY?

The Danish EPA has estimated the NO_x emission from the Danish power production in year 2020. Based on these figures the NO_x emission from the WtE industry will by using SNCR and an average emission at 200 mg/Nm^3 contribute to 17% of the total NO_x emission from the power industry.

By introducing SCR and a NO_x emission at 70 mg/Nm^3 the NO_x emission from the Danish WtE facilities will be reduced from 17% to 6%.

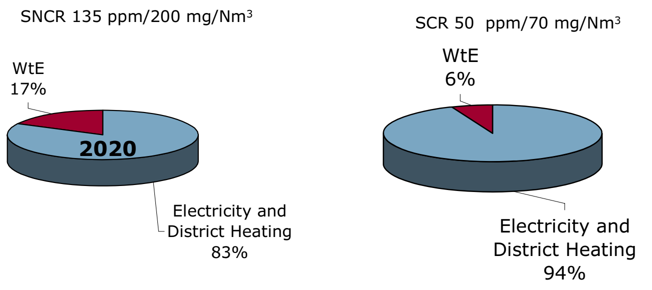


Figure 7. NO_x contribution by WtE in year 2020 by using SNCR and SCR respectivel. Source: Danish EPA

Whether or not the reduction of NO_x from 17% to 6% is significant enough to justify mandatory SCR over SNCR is very much a political decision that is at present being discussed among the EU member countries.

As the WtE facilities in the US do not contribute as much to the national power production as in Denmark, where more than 3% of the national electricity consumption is generated by WtE facilities the reduction of NO_x from WtE will not significantly reduce the national NO_x emission. However regional goals for low NO_x is to a higher extent seen as the driver for introducing SCR in the US.

Attachment 4 – B&W Emission Target Letter

babcock & wilcox power generation group
20 south van buren avenue · p.o. box 351 · barberton, oh 44203-0351 usa
phone 330.753.4511 · fax 330.860.1886 · www.babcock.com

Alpine Energy Group
1900 Wazee St. Suite 311
Denver, CO 80202

Attention: Mr. A Hixson

Re: Preliminary Emissions values for RDF fired boiler with AQCS – St Croix Facility.

Dear Andy,

Per our recent phone conversations, B&W has done a preliminary review of the required emission limits for the proposed St Croix facility and determined that the values presented for major pollutants and reproduced below are generally reasonable targets for design purposes. We would expect to be able to develop those values into guarantees during a more rigorous proposal design phase.

If, during the design phase, it becomes apparent that we will be unable to meet the limits set out below, we will notify Alpine energy as soon as possible so that a solution can be worked out.

Pollutant	***Emission limit estimate***
NO_x	18.9 lb/hr
SO_x	10.2 lb/hr
CO	23.1 lb/hr
PM_{10} (total)	7.2 lb/hr
VOC	14.4 lb/hr

Our basis for these rates is the guarantees provided by B&W for the new West Palm Beach Facility which is the model for the proposed equipment. This unit is in production, but not yet in operation.

B&W has supplied 62 RDF units in North America.

We have investigated the use of an SCR for NOx control when firing Municipal Solid Waste (Waste-to-Energy Units). There are a few applications in Europe, but not in North America. The last MSW unit permitted in the US was 20 years ago, and the NOx emission requirements at the time were such that an SNCR system had sufficient removal capability. Over the past 15 years, some EU countries have been targeting lower NOx emission levels that can only be achieved with the use of clean SCRs. We are modeling our system on these lines. By locating the SCR at the end of the Air Quality Control system with sufficient flue gas reheat to meet the catalyst reactivity requirements the catalyst poisons will be removed upstream of the SCR, leading to a longer catalyst life.

We hope this information helps in your permitting process and moves the project forward.

Best regards

Jim Watson
FPD Proposal Manager
Babcock & Wilcox Power Generation Group, Inc.
(330) 860-1084