Biomass Boiler Study

Heartland Renewable Energy
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Stanley Consultants INC.
A Stanley Group Company
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Executive Summary

This report provides a comprehensive review on the technical and economic feasibility of burning spray dried waste yeast broth produced as a byproduct in an energy beet biofuel facility. Results of this study are expected to be used by Heartland Renewable Energy (HRE) and their partners to assist with the development of an energy beet biofuel industry in North Dakota.

To accomplish the study's objective, approximately ten gallons of waste yeast broth containing 80 percent water by weight was obtained from HRE's stored supply and was shipped to Aveka, Inc., located in Woodbury, Minnesota, for drying. The dried sample was then shipped to Hazen Research, Inc. located in Golden, Colorado, where a typical detailed fuel analyses suitable for the boiler vendor's use was completed.

The fuel analyses for the waste yeast broth before drying (wet analysis) and the fuel analysis obtained from Hazen Research, Inc., for the dried sample (dry analysis), as well as plant size information were sent to the following seven biomass boiler vendors; Engineered Products of Idaho (EPI), Hurst Boilers, McBurney, King Coal, Inc., Itasca, English Boiler, and George K. Moss. Vendors were requested to provide "go" or "no go" assessment as to whether the fuel, wet or dry, would be suitable for continuous long-term operation with their specific boiler technology. If "go", budgetary proposals were requested from biomass boiler vendors for suitable boiler and associated standard emission control equipment.

Two manufacturers determined that the product was a "go" and provided proposals. Hurst Boiler provided a proposal for their water tube boiler (stoker type boiler) and EPI provided a proposal for their Bubbling Fluidized Bed (BFB) gasifier. Itasca Power declined to bid over concerns of the economic feasibility of drying and then burning the high moisture fuel. English Boiler declined to bid because of their concern over the high alkali content in the fuel leading to furnace scaling and pluggage in their boiler. We contacted McBurney, King Coal, and George K. Moss several times to discuss the opportunity; they did not respond.

Four cases were developed and evaluated; the four cases are the Hurst Boiler (stoker type boiler), EPI's BFB gasifier, an anaerobic digester, and natural gas boiler. A life-cycle cost analysis was developed that compared the four cases; the base case in the analysis is the natural gas boiler option. Of the biomass boiler alternatives, the Hurst biomass boiler offers the lower capital cost and the lower life-cycle cost for burning the spray dried waste yeast broth. See Table 1 below for summary of results.

Table 1 Life-Cycle Cost Analysis Summary of Results

PROJECT SUMMARY	Base Case: NG Package Boiler	Alternative 1: Digester	Alternative 2: Hurst Boiler	Alternative 3: EPI BFB Gasifier
Capital Cost	$3,000,000	$16,600,000	$23,100,000	$24,600,000
10 Year Cost	$54,802,738	$50,480,076	$58,305,641	$60,461,474
15 Year Cost	$83,051,653	$69,453,125	$78,657,145	$81,283,494
20 Year Cost	$113,007,342	$89,991,128	$101,185,661	$104,401,971
30 Year Cost	$178,522,822	$136,551,531	$154,084,640	$158,933,091
10 Year Present Value	$42,815,314	$42,605,274	$50,077,232	$52,073,230
15 Year Present Value	$57,814,897	$52,675,732	$60,874,695	$63,119,679
20 Year Present Value	$70,277,434	$61,216,597	$70,239,188	$72,728,842
30 Year Present Value	$89,252,903	$74,674,737	$85,500,837	$88,457,641
Payback (Years)	Base Case	9.8	19.9	26.6

Sensitivity analyses were completed on natural gas pricing and capital cost by varying each parameter separately while holding all other input parameters constant. The natural gas pricing sensitivity analysis showed that increasing gas costs has more impact on the biomass boiler alternatives than the digester alternative. At $10 per million BTU, the payback period for the Hurst biomass boiler alternative decreased from 19.9 years to 7.6 years while the digester decreased from 9.8 years to 5.4 years. To achieve a 4-year payback on the Hurst biomass boiler, natural gas prices would need to increase to $15.50 per MMBtu. The current market price for natural gas is approximately $4.30 per MMBtu.

The capital cost sensitivity analysis showed that capital cost for the Hurst biomass boiler alternative would need to be reduced by $5.9 million (approximately 25 percent reduction) to achieve a 10-year payback.

A test burn was completed by Hurst. Their results conclude that dried waste yeast broth can be burned on a continuous long-term basis by utilizing a secondary fuel to mitigate any combustion issues. To accomplish this, Hurst recommended three different furnace/combustor systems as viable options including blending the dried waste yeast broth with another wetter solid fuel in a water tube boiler; utilizing cyclonic solid fuel burners with supplemental natural gas in a water tube boiler; or by adding natural gas intermittently in a fluidized bed boiler.

Both the biomass boiler and the digester alternatives offer advantages and disadvantages with respect to utilizing the waste yeast broth for offsetting some of the plant's thermal load requirements. For this study,, any shortfall in meeting the plant's total thermal load requirements was assumed to be made up with natural gas. Natural gas usage for the base case natural gas package boiler, the anaerobic digester, the Hurst biomass boiler alternative, and EPI's BFB gasifier alternative were 85.9, 48.0, 36.0, and 34.5 MMBtu/hr, respectively (see Appendix I). Below is a summary of the advantages and disadvantages of the biomass boiler and digester alternatives.

Biomass boiler advantages:

- Recovers the most energy from the waste yeast broth. Least amount of natural gas is needed to supplement steam production for the plant. Consequently, natural gas is conserved.
- Smallest carbon footprint.
- Reduced volumetric waste stream from the plant as compared to the natural gas package boiler alternative which assumes 100 percent of the waste yeast broth is disposed of off-site. The annual waste steam for the biomass boiler options is estimated to be 16,290 tons. The annual waste stream for the natural gas packaged boiler is estimated to be 79,840,000 gallons.

Biomass boiler disadvantages:

- Higher capital cost as compared to the natural gas package boiler and anaerobic digester options.
- Storage and handling of dried waste yeast broth potentially problematic.

Digester advantages:

- Lower capital cost and evaluated cost as compared to biomass boiler alternatives.
- Lowest volumetric waste stream for disposal. The annual waste stream for the digester is estimated to be 6,500 tons.

Digester disadvantages:

- Less energy recovered as compared to biomass boiler alternatives. More natural gas is needed to supplement steam production for the plant.
- Larger carbon footprint as compared to biomass boiler alternatives because more natural gas is required in this option as compared to the biomass option.

While the dried waste yeast broth is a viable fuel for burning in a biomass boiler, the economics show the anaerobic digester alternative has a lower net present value than the biomass boiler alternative over the lifetime of the facility. Future carbon credits could change the economics to favor the biomass boiler. This study concludes that spray dried waste yeast broth produced as a byproduct in an energy beet biofuel facility is a viable fuel with the smallest carbon footprint.

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Section 1

Project Overview

Background

Heartland Renewable Energy (HRE) requested an evaluation of various biomass boiler alternatives to determine the economics of burning spray dried waste yeast broth produced after fermentation of energy beets used for biofuel production. Utilizing spray dried waste yeast broth as a fuel source to generate steam will demonstrate good environmental stewardship while reducing the overall operating costs of the ethanol production facility. Operating costs are reduced by offsetting thermal energy needs that are normally provided with other purchased fuels.

The results from this evaluation will be used to assist HRE and their partners with the development of an energy beet biofuel industry in five regional locations with 20 million gallon per year (MGY) production facilities across North Dakota.

Objective

The objective of this study was to determine whether spray dried yeast broth from an energy beet biofuel facility is suitable and economically feasible for burning in a biomass boiler on a continuous long-term basis.

Approach

The steps below were completed to accomplish the stated objective.

The first step was to obtain a dried sample of the waste yeast broth. As produced, the waste yeast broth contains approximately 80 percent water by weight (see Appendix A for typical analysis). Ten gallons of the waste yeast broth was obtained from HRE's stored supply and was shipped to Aveka, Inc., located in Woodbury, Minnesota, for drying. A customer report was prepared by Aveka and is included in Appendix C. The dried material was returned in sealed plastic bags.

The second step was to obtain typical fuel analysis of the dried material suitable for the boiler vendor's use. The dried material was shipped to Hazen Research, Inc. located in Golden, Colorado, where the following analyses were performed:

- Ultimate, proximate, and BTU analysis.
- Chlorine analysis.
- Differential thermal analysis.
- Ash fusion temperatures.
- Ash elemental analysis.
- Chlorine in ash.
- Carbon dioxide in ash.
- Sieve analysis.

Results from the analysis were prepared by Hazen Research and are included in Appendix B.

The third step was to solicit budgetary proposals from biomass boiler vendors for the boiler and associated emission control equipment. The fuel analyses for the waste yeast broth before drying (wet analysis), as well as the fuel analysis obtained from Hazen Research, Inc., for the dried sample (dry analysis), were sent to the following biomass boiler vendors:

- Engineered Products of Idaho (EPI).
- Hurst Boilers.
- McBurney.
- King Coal, Inc.
- Itasca.
- English Boiler.
- George K. Moss.

Vendors were requested to provide "go" or "no go" assessment as to whether the fuel, wet or dry, would be suitable for continuous long-term operation with their specific boiler technology. If "go", vendors were asked to provide budgetary proposals for a biomass boiler and associated emission control equipment standardly used for addressing NO_x, SO_2, PM, CO, VOC, and hazardous air pollutants with the proposed boiler.

The fourth step was to perform life-cycle cost analysis that compared the biomass boiler alternatives (from the proposals received) and an anaerobic digester alternative to a base case option. The base case option used in the analysis was a natural gas package boiler. For the base case, the waste yeast broth was assumed to be disposed of for a net cost of $0 per gallon. Sensitivity analyses were completed on select parameters, including capital cost and natural gas pricing. The analysis was used to determine the most economically feasible alternative, as well

as a payback period with respect to the base case option. A review of the results is included in Section 6 of this report.

The fifth and final step was to perform a test burn on the most economically feasible biomass boiler alternative. The purpose of the test burn was to assess the viability of burning the fuel in the proposed boiler by reviewing fouling, flame stability, and ash deposition characteristics. The associated test burn report prepared by Hurst Boiler is included in Appendix K.

Section 2

Basis of Design

Introduction

This section describes the basis of design for the biomass boiler equipment that will be used to generate steam by burning waste yeast broth produced at an energy beet biofuel production facility.

Fuel and Ash Analyses

Approximately ten gallons of waste yeast broth (also described as "clarified wine") was obtained from HRE's stored supply. The waste yeast broth was shipped to Woodbury, Minnesota, where it was dried to approximately 5 percent moisture by Aveka, Inc., using a lab scale spray dryer. The associated spray drying technical report is included in Appendix C.

A sample of the dried material was then sent to Golden, Colorado, where it was analyzed by Hazen Research Inc., in their laboratory. The complete fuel and ash analyses report is included in Appendix B.

Boiler Performance Requirements

The boiler performance requirements used for this study were based on the flow rates and temperatures included on the mass and energy balances provided by HRE (see Appendix D and E).

The fuel heating value used in the study was based on the dried yeast broth analysis results provided by Hazen Research Inc.

Boiler vendors were furnished with fuel analysis and approximate fuel feed rate and were requested to provide a budgetary proposal for generating 200 psig, saturated steam. In addition, the boiler vendors were asked to include the capability of using natural gas as a backup fuel. Both vendors that responded provided proposals for a 60,000 lb/hr boiler. Budget capital costs

were scaled down to a 50,000 lb/hr boiler size to match steam production shown on HRE's mass balance.

Plant Total Thermal Load

According to Energy Beet Research Application, the expectation is that 75 percent of the plant thermal needs can be provided by the waste yeast broth. The mass balance shows the steam flow rate from the boilers to be 50,200 lb/hr (see Appendix D). Consequently, the plant total thermal load used in the study was calculated as the equivalent of approximately 67,000 lb/hr steam of 200 psig, saturated steam.

Section 3

Equipment Review

General

Vendors that furnish biomass boiler equipment in the size range being considered in this study were contacted for boiler and associated emission control budget proposals for burning dried waste yeast broth produced at an energy beet biofuel production facility. The boiler types offered by the various vendors include stoker boiler, bubbling fluidized bed boiler, suspension-fired boiler, hybrid gasifier, and bubbling fluidized bed gasifier. Some vendors offer more than one of the technologies. Although circulating fluidized bed boiler offer advantages in efficiency and emissions, they are not considered economically viable, due to their high capital cost and may not be commercially available in the size range.

Requests for budget proposals were sent to seven boiler vendors. Proposals were returned from Hurst Boiler (stoker type boiler) and Energy Products of Idaho (bubbling fluidized bed gasifier) and were used in this study. Itasca Power (bubbling fluidized bed boiler) declined to bid over concerns of the economic feasibility of drying and then burning the high moisture fuel. English Boiler (stoker) declined to bid because of their concern over the high alkali content in the fuel leading to furnace scaling and pluggage. McBurney (suspension fired boiler, stoker), King Coal (stoker boiler), and George K. Moss (gasifier, stoker, bubbling fluidized bed boiler) did not respond.

Below are general descriptions for the boiler technologies proposed by Hurst and Energy Products of Idaho (EPI).

Hurst Boiler

The proposed Hurst Boiler utilizes a stoker water-tube type boiler design and includes a flaking grate furnace section with two cyclonic solid fuel burners with natural gas starter and part-time supplemental fuel source to even out full combustion. Fuel enters the boiler through screw metering bins with variable speed control. It is maintained on a sloped, reciprocating grate. A

drag-chain conveyor with a trough is used for ash removal. The fuel is combusted with air over the grate. Radiant heat is transferred to the water-tube sections. Hurst proposes to use a multi-pollutant emission control system from Tri-Mer to control carbon monoxide and particulates in the exhaust gases downstream of the boiler.

EPI Bubbling Bed Gasifier

Upward blowing streams of combustion air and gases are used to suspend, or "fluidize", fuel and bed ash material (typically sand) within a vessel. Fine particle and low density fuels, such as the dried waste yeast broth, are pneumatically injected directly into the bed material. Gasification occurs in the lower section of the vessel. As the combustible gases move upward, more air is added to complete combustion in the upper section of the vessel. A baghouse will be used to collect particulates leaving the boiler.

Arrangement

A flow diagram showing the conceptual arrangement of equipment for the base case natural gas package boiler is included in Appendix F (see FD-1). The base case uses commercially available natural gas to meet 100 percent of total plant thermal load requirements. It is assumed that the waste yeast broth stream from the ethanol plant is disposed of for a net cost of $0 per gallon.

A flow diagram showing the conceptual arrangement of equipment for the digester alternative (Alternative 1) is included in Appendix F (see FD-2). Waste yeast broth is delivered to an anaerobic digester where it is converted to methane gas. The amount of methane produced is not enough to meet the total plant thermal load requirements. Consequently, commercially available natural gas is used to supplement the digester methane for the production of steam in a common gas-fired package boiler. The digester also produces a solids byproduct rich in nutrients that can be sold as a soils conditioner.

A flow diagram showing the conceptual arrangement of equipment for the two biomass boiler alternatives (Alternative 2 & 3) is included in Appendix F (see FD-3). Waste yeast broth is delivered to a multi-effect evaporator to remove water to a solids content of approximately 55 percent. The waste yeast broth is then dried in a spray dryer to approximately 90- 95 percent solids before being burned in a biomass boiler. Exhaust gas leaves the biomass boiler at 680° F and is used in the spray dryer for drying incoming waste yeast broth. Steam produced by the biomass boiler is not enough to meet the total plant thermal load requirements. Likewise, the biomass boiler exhaust gas energy to the spray dryer is not enough to meet drying requirements. Consequently, natural gas is used to supplement steam production via a separate gas-fired package boiler, as well as supplement spray dryer energy input requirements. Solid waste from the boiler is collected and disposed. The exhaust gas leaving the spray dryer will be approaching a saturated condition and will require additional emission control equipment for treating the flue gas before discharging to atmosphere.

Section 4

Technical Considerations

General

The purpose of this section is to identify and discuss key technical considerations associated with the development of a dried waste yeast boiler plant. Included are discussions on fuel storage and handling, and fuel analyses.

Fuel Storage and Handling

The waste yeast broth byproduct from the ethanol process contains 80 percent water by weight. The fuel in this form appears to be suitable for long-term storage without chemical breakdown based on dried sample analyses of the stored liquid completed more than two years apart. The analyses of the samples performed on April 21, 2008, and July 14, 2010, are included in Appendix B.

In dried form, however, the waste yeast broth byproduct is hygroscopic absorbing water from the surrounding air. According to the Aveka Spray Drying Report included in Appendix C, the material begins to mass together and changes to a darker brown color after two hours of exposure in humid air. After five hours, the material masses together, is completely brown, and is sticky to the touch. Consequently, traditional storage of the dried material will be problematic. To maintain the powder characteristic observed after drying, the material would need to be stored in a moisture-free environment.

Another possible alternative is to spray dry the fuel just before it is admitted to the boiler minimizing the exposure time to the surrounding air. In this arrangement, the fuel would be stored in its liquid form. Storage volumes for the liquid fuel will be significantly higher as compared to storing dried fuel because of the high water content.

Fuel handling for the dried fuel will likely also be problematic because of the hygroscopic characteristic. The dried fuel may be able to be transported pneumatically with dried air.

Transport distances should be minimized. Storage and handling for this material need further investigation in the next phase of the project.

Fuel Analysis

A fuel analysis of the dried waste yeast broth is included in Appendix B. The analysis was included with a request for proposal and provided to perspective biomass boiler vendors. Multiple vendors commented on the high alkali levels in the fuel which can lead to slagging and fouling issues in the boiler. English Boiler (stoker boiler) declined to provide budget proposal because of their concern over the high alkali content in the fuel. Hurst Boiler (Hurst) commented on the high chlorine and relatively high sulfur content but said they could utilize the fuel. High chlorine levels result in high hydrogen chloride (HCl) concentrations in the boiler flue gases and, possibly, high temperature corrosion.

For the test burn, Hurst requested two samples of the dried waste yeast broth so that they could analyze them independently and in parallel. One sample was analyzed by the Hurst engineering team at the factory located in Coolidge, Georgia. The other sample was sent directly to an independent laboratory that Hurst uses to conduct combustion tests. Results from the independent laboratory analysis were reported to be consistent with those from Hazen Research, Inc dated July 14, 2010 (included in Appendix B).

Hurst provided three (3) options for burning the dried waste yeast broth subsequent to the burn test. The first option mixes the dried waste yeast broth with a wetter biomass material. The second and third options utilize a minor and intermittent amount of supplemental/start-up natural gas to mitigate the combustion issues of the tested fuel as the main source of fuel. Hurst also reported that based on the test burn results, initial feedback from various secondary pollution control system manufacturers was that their standard secondary pollution control systems would be slightly modified for burning the dried waste yeast broth (see Appendix K for complete Test Burn Report from Hurst).

Section 5

Environmental

General

Stanley Consultants reviewed current Federal and State (North Dakota) environmental regulations for this study to identify applicable emission limitations. The following is a summary of what was determined for natural gas boilers and biomass boilers. It is assumed in this study that the 20 million gallon per year ethanol plant being considered by Heartland Renewable Energy would not be a Major Source of Hazardous Air Pollutants (HAPs).

For a natural gas boiler with a maximum hourly heat input of 100 MMBtu, there is an applicable New Source Performance Standard (NSPS) that applies. NSPS Subpart Dc applies to new or reconstructed small industrial-commercial-institutional steam generating units with a maximum hourly heat input of 100 MMBtu or less but greater than 10 MMBtu. In Subpart Dc, there are emissions standards for sulfur dioxide (SO_2) and Particulate Matter (PM). However, if the fuel for the boiler is exclusively natural gas, there are no specific emission limits that apply in Subpart Dc. Because this facility is a minor source for HAPs, the proposed industrial-commercial-institutional boiler GACT for area sources applies; however, since the boiler exclusively combusts natural gas, there are no emission limits from that proposed regulation that would apply. A review of the North Dakota Administrative Code did not uncover any state level applicable emission limitations for a natural gas boiler of this size.

For a biomass boiler with a maximum hourly heat input 100 MMBtu, there is an applicable NSPS that applies. NSPS Subpart Dc applies to new or reconstructed small industrial-commercial-institutional steam generating units with a maximum hourly heat input of 100 MMBtu or less but greater than 10 MMBtu. In Subpart Dc, there are emissions standards for sulfur dioxide (SO_2) and Particulate Matter (PM). The SO_2 standards do not apply to a boiler that combusts biomass exclusively. Subpart Dc does contain a PM emissions standard for biomass (wood) of 0.10 lbs/MMBtu and an opacity limit of 20 percent. Because this facility is a minor source for HAPs, the proposed industrial-commercial-institutional boiler GACT for area sources applies. The

proposed area source boiler GACT limits on biomass for PM and carbon monoxide (CO) are 0.03 lb/MMBtu and 100 ppm (dry) at 7 percent oxygen, respectively. The PM standard for the area source boiler GACT is more stringent than the NSPS. Though the proposed area source boiler GACT is not yet final, this study will utilize the area source boiler GACT PM and CO limits. It should also be noted that additional changes in the stated emission limits may be developed during permitting of the facility. A review of the North Dakota Administrative Code did uncover an applicable PM limitation. North Dakota Administrative Code 33-15-05-02 "Maximum Allowable Emissions of PM from Fuel Burning Equipment Used For Indirect Heating" includes a PM emission limit for a new boiler with a maximum hourly heat input of 100 MMBtu of 0.444 lbs/MMBtu. The area source boiler GACT and NSPS PM limits are more stringent than the state regulation referenced here.

Section 6

Cost Estimates and Life-Cycle Cost Analysis

General

An anaerobic digester alternative (Alternative 1) and biomass boiler alternatives (Alternatives 2 and 3) were compared to a base case natural gas package boiler. The cases were evaluated using the same total thermal loads for the plant for each alternative. The plant total thermal load used in the study, established in Section 2 - Basis of Design, is the equivalent of 67,000 lb/hr steam of 200 psig, saturated steam.

The digester uses the waste yeast broth in liquid form to produce methane gas. The amount of methane gas produced would only be a portion of the total thermal load requirement. The balance was assumed to be made up with commercially available natural gas. The digester off-gas would be mixed with natural gas and burned in single gas-fired package boiler.

Each of the biomass boiler options only produces a portion of the thermal load requirement. The balance of the thermal load was assumed to be made up by burning natural gas in a separate package boiler.

Flow diagrams showing equipment arrangements are included in Appendix F.

Cost Estimates

Cost estimates were prepared for the two biomass boiler alternatives evaluated (Alternative 2 and 3) and are included in Appendix G. The capital cost for the natural gas package boiler (base case) and digester option (Alternative 1) were based on previous studies performed by Stanley Consultants.

Biomass boiler budget proposals were obtained from Hurst Boiler for their water tube boiler design and Energy Products of Idaho for their bubbling fluidized bed gasifier. Proposals included pricing for the biomass boiler, economizer, FD and ID fans, backup natural gas system, metering

bins and fuel feed system, boiler control system, emission control equipment, and a 100 feet tall stack with continuous emission monitoring. In addition, the bubbling fluidized bed gasifier included pricing for bed media storage equipment. Evaporator and spray dryer equipment pricing was obtained from Niro. Other costs were estimated using Stanley Consultants' estimating department and project database. Vendor proposals are included in Appendix J.

Total installed costs were developed by including costs for the following components:

- General Contractor Overhead and Profit – represents the contractor's overhead costs and his profit for accepting the risks associated with the work.
- Undeveloped Design Details – addresses design details which have yet to be prepared at this preliminary stage of the project.
- Engineering, Permitting, and Administrative – is the cost for detailed engineering and design to prepare project specifications; drawings, construction packages, and equipment bid documents; as well as construction permits and environmental permits.
- Contingency – included for unanticipated activities arising during the design and construction phases.

Life-Cycle Cost Analysis

A life-cycle cost analysis was developed to compare a base case natural gas package boiler option to the anaerobic digester and biomass boiler alternatives by implementing the initial capital costs, fuel costs, auxiliary power costs, maintenance and repair costs, solid byproduct disposal costs, taxes and insurance costs, and escalation factors into an economic model. A 10, 15, 20, and 30 Net Present Value (NPV) lifecycle analysis and payback period were calculated for each alternative.

A summary of the results is listed below. The life-cycle cost analysis spreadsheet is included in Appendix H.

Table 6-1 Life-Cycle Cost Analysis Summary of Results

Capital Cost	$3,000,000	$16,600,000	$23,100,000	$24,600,000
10 Year Cost	$54,802,738	$50,480,076	$58,305,641	$60,461,474
15 Year Cost	$83,051,653	$69,453,125	$78,657,145	$81,283,494
20 Year Cost	$113,007,342	$89,991,128	$101,185,661	$104,401,971
30 Year Cost	$178,522,822	$136,551,531	$154,084,640	$158,933,091
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20 Year Present Value	$70,277,434	$61,216,597	$70,239,188	$72,728,842
30 Year Present Value	$89,252,903	$74,674,737	$85,500,837	$88,457,641
Payback (Years)	Base Case	9.8	19.9	26.6

Sensitivity Analysis

Input parameter values used in the life-cycle cost analysis including biomass feed rate, biomass heating value, biomass ash content, and equipment auxiliary power requirements were based on project mass and energy balances, biomass fuel analysis, and vendor proposals. Natural gas and electric costs were based on the "Annual Energy Outlook 2010" prepared by the U.S. Energy Information Administration.

A sensitivity analysis was completed by varying biomass boiler capital costs while holding all other input parameters constant. In order to achieve a 10-year payback, the capital cost of the Hurst biomass boiler alternative would need to be reduced by approximately $5.9 million. Similarly, the capital cost of the EPI BFB gasifier alternative would need to be reduced by approximately $7.6 million. Given the amount of additional equipment required for the boiler alternatives, it is not likely such a low cost differential can be achieved. As originally evaluated, the estimated capital cost difference between the Hurst biomass boiler alternative and the base case natural gas package boiler option was $20.1 million. The corresponding payback period was 19.9 years. Likewise, the estimated capital cost difference between the EPI BFB gasifier and the case natural gas package boiler option was $21.6 million and the corresponding payback period was 26.6 years.

The other sensitivity analysis completed was on natural gas pricing. The life cycle cost analysis included in Appendix H was modeled with a natural gas price of $6.47 per MMBtu. The corresponding payback period for the Hurst biomass boiler and the EPI BFB gasifier alternatives were 19.9 years and 26.6 years, respectively. Higher gas prices reduce the payback period for the biomass boiler alternatives. Assuming a natural gas price of $10 per MMBtu, the payback period of the Hurst biomass boiler and EPI BFB gasifier alternatives were 7.6 years and 8.9 years, respectively.

Section 7

Results and Conclusions

Results

The project objectives were to determine whether spray dried waste yeast broth from an energy beet biofuel facility can be successfully burned on a continuous long-term basis in a commercially available biomass boiler and to determine the economic feasibility.

A sample of the waste yeast broth was spray dried to approximately 95 percent solids. A detailed fuel analysis was then completed on the dried sample. The analysis was provided to several biomass boiler vendors for review with their respective boiler technologies. Two of the seven vendors contacted, Hurst Boiler and Energy Products of Idaho (EPI), provided "go" assessments for long-term operation with their biomass boiler technology.

To assess the economic feasibility, the two biomass boiler alternatives and an anaerobic digester alternative were compared to a base case natural gas package boiler option in a life-cycle cost analysis. Cost estimates were completed showing project capital costs for the base case natural gas package boiler, the anaerobic digester, the Hurst biomass boiler alternative, and EPI's bubbling fluidized bed (BFB) gasifier alternative to be $3,000,000, $16,600,000, $23,100,000, and $24,600,000, respectively. Net present values were calculated for 10 years, 15 years, 20 years, and 30 years. The natural gas package boiler was shown to be the low evaluated cost option in the first years of operation. Payback periods for the anaerobic digester, Hurst biomass boiler alternative, and the EPI BFB gasifier alternative were calculated to occur at 9.8 years, 19.9 years, and 26.6 years, respectively.

Sensitivity analyses were completed on capital costs and natural gas pricing. In order to reach a 10-year payback, capital costs for the Hurst biomass boiler alternative and the EPI BFB gasifier alternative would need to be reduced by $5.9 million (approximately 25% reduction) and $7.6 million (approximately 30% reduction), respectively. The natural gas pricing sensitivity analysis showed that increasing gas costs favors the biomass boiler options. At $10 per million BTU, the

payback period for the Hurst biomass boiler alternative and the EPI BFB gasifier alternative are 7.6 years and 8.9 years, respectively.

A test burn was completed by Hurst to confirm viability of burning the dried waste yeast broth on a long-term continuous basis. Based on the results of the test, Hurst recommended three different furnace/combustor systems as viable options including:

- Hurst water-tube boiler with their standard flaking grate utilizing a mixture of the dried waste yeast broth and another wetter biomass material such as woody biomass.
- Hurst water-tube boiler with their standard flaking grate utilizing two cyclonic solid fuel burners with natural gas starter and part-time supplemental fuel source to even out full combustion.
- Fluidized bed burner provided by a manufacturing partner of Hurst's that is matched to a water tube boiler and control system with in-bed natural gas start-up burners to maintain constant bed temperature.

Conclusions and Recommendations

The results of the test burn performed by Hurst conclude that dried waste yeast broth can be burned in a biomass boiler on a continuous long-term basis by utilizing a secondary fuel to mitigate any combustion issues. This can be accomplished by blending the dried waste yeast broth with another wetter solid fuel in a water tube stoker boiler; utilizing cyclonic solid fuel burners with supplemental natural gas in a water tube stoker boiler; or by adding natural gas intermittently in a fluidized bed boiler.

Both the biomass boiler and the digester alternatives offer advantages and disadvantages with respect to utilizing the waste yeast broth for offsetting some of the plant's thermal load requirements. For this study, any shortfall in meeting the plant's total thermal load requirements was assumed to be made up with natural gas. Natural gas usage for the base case natural gas package boiler, the anaerobic digester, the Hurst biomass boiler alternative, and EPI's BFB gasifier alternative were 85.9, 48.0, 36.0, and 34.5 MMBtu/hr, respectively (see Appendix I). Below is a summary of the advantages and disadvantages of the biomass boiler and digester alternatives.

Biomass boiler advantages:

- Recovers the most energy from the waste yeast broth. Least amount of natural gas is needed to supplement steam production for the plant. Consequently, natural gas is conserved.
- Smallest carbon footprint.
- Reduced volumetric waste stream from the plant as compared to the natural gas package boiler alternative which assumes 100 percent of the waste yeast broth is disposed of off-site. The annual waste stream for the biomass boiler alternatives is estimated to be 16,290 tons. The annual waste stream for the natural gas packaged boiler is estimated to be 79,840,000 gallons.

Biomass boiler disadvantages:

- Higher capital cost as compared to the natural gas package boiler and anaerobic digester options.
- Storage and handling of dried waste yeast broth potentially problematic.

Digester advantages:

- Lower capital cost and evaluated cost as compared to biomass boiler alternatives.
- Lowest volumetric waste stream for disposal. The annual waste stream for the digester is estimated to be 6,500 tons.

Digester disadvantages:

- Less energy recovered as compared to biomass boiler alternatives. More natural gas is needed to supplement steam production for the plant.
- Larger carbon footprint as compared to biomass boiler alternatives because more natural gas is required in this option as compared to the biomass option.

While the dried waste yeast broth is a viable fuel for burning in a biomass boiler, the economics show the anaerobic digester alternative has a lower net present value than the biomass boiler alternative over the lifetime of the facility (see Appendix H). Future carbon credits could change the economics to favor the biomass boiler. This study concludes that spray dried waste yeast broth produced as a byproduct in an energy beet biofuel facility is a viable fuel with the smallest carbon footprint.

Appendix A

Waste Yeast Broth Fuel Analysis

SDK Laboratories

1000 Corey Road
P.O. Box 886
Hutchinson, KS 67504-0886
620-665-5661
FAX: 620-665-0559
TOLL FREE: 877-464-0623
www.sdklabs.com

Sample # 21046
Sample: Liquid COMPOSITE FEED
Other ID:

Date Received: 03/31/2008
Date Reported: 04/08/2008
Total Fee: 202.50

HEARTLAND RENEWABLE ENERGY
PHIL ALLEN
407 W. MISSISSIPPI DR
MUSCATINE, IA 52761

ANALYSIS

	Dry Basis	As Received	
Moisture, Karl-Fischer		80.20	%
Dry Matter		19.80	%
TKN-Total Kjeldahl Nitrogen	1.11	0.22	%
Ash	13.94	2.76	%
Sodium	0.30	0.06	%
Chloride	1.87	0.37	%
Sulfur	0.71	0.14	%
Fructose		Less than 0.1	%
Glucose		Less than 0.1	%
Lactose		0.1	%
Maltose		Less than 0.1	%
Sucrose		Less than 0.1	%
Lactic Acid		Less than 0.02	%
Acetic Acid		0.26	%
Butyric Acid		Less than 0.01	%
Propionic Acid		Less than 0.01	%
Valeric Acid		Less than 0.01	ppm
Ethanol	25.15	4.98	%
Phosphorus as P205	0.19	0.038	%
Potash - K20	7.12	1.41	%

Total Sugars
[illegible]

Approved By:

Copies

ANALYTICAL RESULTS APPLY ONLY TO THE SUBMITTED SAMPLE AND MAY NOT REFLECT RESULTS OF SEEMINGLY IDENTICAL MATERIAL OR PRODUCTS.

Appendix B

Dried Waste Yeast Broth Fuel Analysis

Hazen Research, Inc.
4601 Indiana Street
Golden, CO 80403 USA
Tel: (303) 279-4501
Fax: (303) 278-1528

Date July 14 2010
HRI Project 002-BUI
HRI Series No. F135/10-1
Date Rec'd. 06/15/10
Cust. P.O.#

Stanley Consultants
Doug Einck
225 Iowa Avenue
Muscatine, IA 52761

Sample Identification
Spray Dried Lot 10176 1000g
Clarified Wine
-

Reporting Basis >	As Rec'd	Dry	Air Dry
Proximate (%)			
Moisture	5.48	0.00	4.31
Ash	29.76	31.49	30.13
Volatile	57.87	61.22	58.58
Fixed C	6.89	7.29	6.98
Total	100.00	100.00	100.00
Sulfur	0.665	0.703	0.673
Btu/lb (HHV)	5507	5826	5575
Btu/lb (LHV)	5072		
MMF Btu/lb	8110	8827	
MAF Btu/lb		8504	
Ultimate (%)			
Moisture	5.48	0.00	4.31
Carbon	34.16	36.14	34.58
Hydrogen	4.09	4.32	4.14
Nitrogen	1.61	1.70	1.63
Sulfur	0.66	0.70	0.67
Ash	29.76	31.49	30.13
Oxygen*	24.24	25.65	24.54
Total	100.00	100.00	100.00
Chlorine**	5.018	5.309	5.080

Air Dry Loss (%) 1.22

Forms of Sulfur, as S, (%)

Sulfate		
Pyritic		
Organic		
Total	0.66	0.70

Water Soluble Alkalies (%)

Na2O
K2O

Lb. Alkali/MM Btu= 3.57
Lb. Ash/MM Btu= 54.04
Lb. SO2/MM Btu= 2.41
HGI= @ % Moisture
As Rec'd. Sp.Gr.=
Free Swelling Index=
F-Factor(dry), DSCF/MM BTU= 10,277

Report Prepared By:

Gerard H. Cunningham
Fuels Laboratory Supervisor

* Oxygen by Difference.
** Not usually reported as part of the ultimate analysis.

Hazen Research, Inc.
4601 Indiana Street
Golden, CO 80403 USA
Tel: (303) 279-4501
Fax: (303) 278-1528

Date July 14 2010
HRI Project 002-BUI
HRI Series No. F135/10-1
Date Rec'd. 06/15/10
Cust. P.O.#

Stanley Consultants
Doug Einck
225 Iowa Avenue
Muscatine, IA 52761

Sample Identification:
Spray Dried Lot 10176 1000g
Clarified Wine

Elemental Analysis of Ash (%)

SIO2	84.94
AL2O3	0.85
TIO2	0.09
FE2O3	0.46
CAO	1.56
MGO	1.24
NA2O	0.57
K2O	6.03
P2O5	0.73
SO3	1.58
CL	0.19
CO2	0.17
Total	98.41

Ash Fusion Temperatures (Deg F)

	Oxidizing Atmosphere	Reducing Atmosphere
Initial Softening Hemispherical Fluid	2700+	2700+

Report Prepared By:

Gerard H. Cunningham
Fuels Laboratory Supervisor

Note: The ash was calcined @ 1110 deg F (600 C) prior to analysis

Hazen Research, Inc.
4601 Indiana Street
Golden, CO 80403 USA
Tel: (303) 279-4501
Fax: (303) 278-1528

July 14, 2010

Stanley Consultants
Doug Einck
225 Iowa Avenue
Muscatine, IA 52761

Doug,

Enclosed please find the Differential Thermal Analysis that was performed at Hazen Research, Inc. by Harry Mudgett. Your sample identification corresponds to our control number as follows:

Control Number	**Sample Identification**
F135/10-2	Spray Wire Ash

Please contact me if I may be of further service to you.

Sincerely,

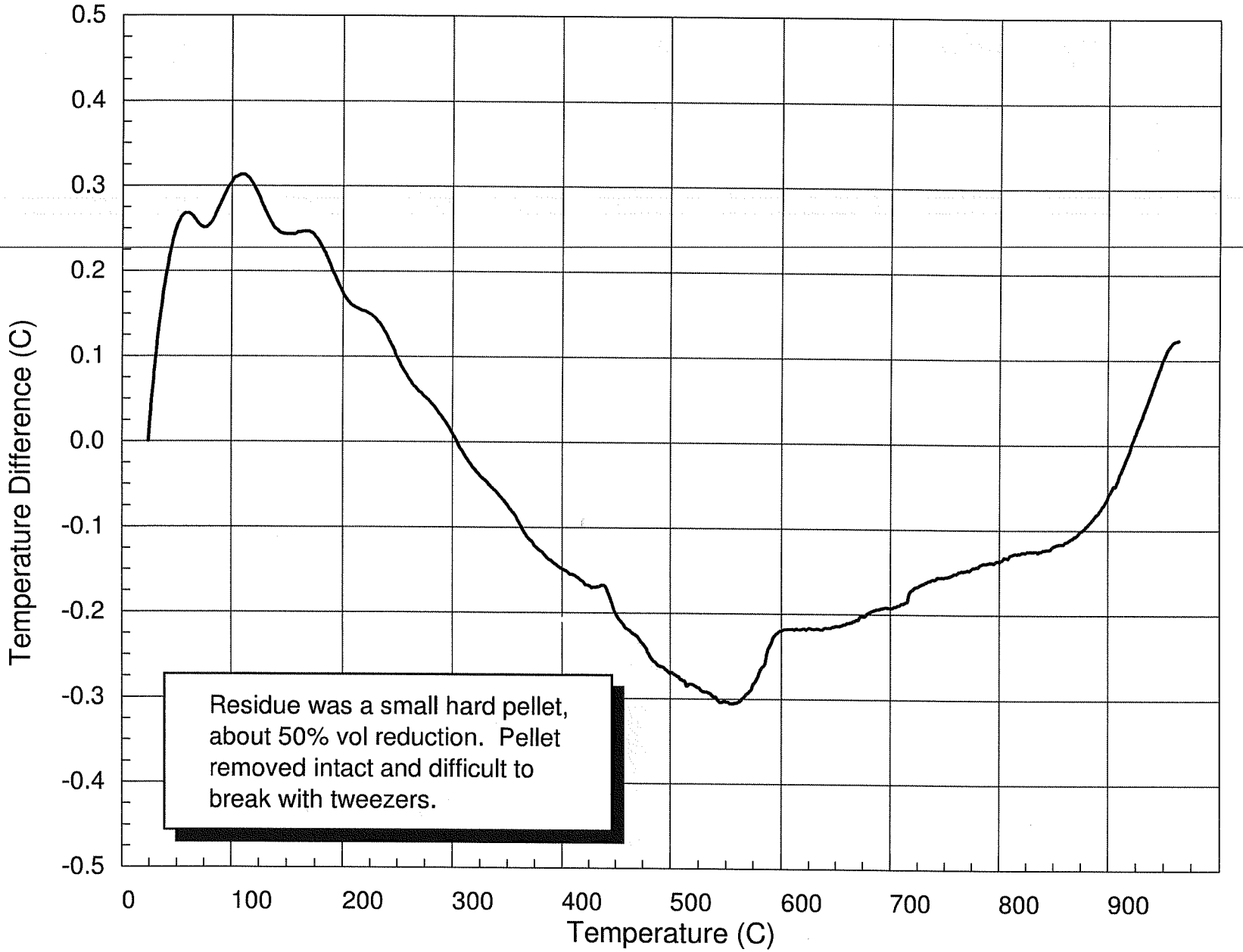
Gerard H. Cunningham
Fuel Laboratory Manager

Hazen Research, Inc

DTA

File Name: F135-10-2.DTA
Size: 20.00
Desc. 1 : Stanley Consult, Spray Wire Ash, F135-2
Desc. 2 : Purge = N2 at 150 cc/m, HR = 20 C/m

Operator: HM
Date: 06/30/2010
Time: 06:59:40
Instrument: DTA 1200



Printed(6/30/2010 9:27:40 AM) Program(Version 4.2.51)

Hazen Research, Inc.
4601 Indiana Street
Golden, CO 80403 USA
Tel: (303) 279-4501
Fax: (303) 278-1528

DATE	07/14/10
HRI PROJECT	002-BUI
HRI SERIES NO.	F135/10
DATE REC'D	06/15/10
CUST P.O. #	

Stanley Consultants
Doug Einck
225 Iowa Avenue
Muscatine, IA 52761

SIEVE ANALYSIS REPORT

Sample Number: F135/10-1
Sample Identification: Spray Dried Lot 1-176 1000g Clarified Wine

Mesh Size Pass - Retained *			Direct Weight, g	Direct Weight, %	Cum. Weight % Retained	Cum. Weight % Pass
		35	24.7	9.90	9.90	90.10
35	-	48	170.9	68.50	78.40	21.60
48	-	65	20.0	8.02	86.41	13.59
65		100	15.7	6.29	92.71	7.29
100		150	13.3	5.33	98.04	1.96
150		200	4.0	1.60	99.64	0.36
200	-	PAN	0.9	0.36	100.00	0.00
		Total	249.5	100.00		

Note: The sample clumped while being sieved.

* Tyler Sieve Sizes

By: Gerard H. Cunningham
Fuel Laboratory Manager

Analysis Report

April 21, 2008

HEARTLAND RENEWABLE ENERGY
407 W. MISSISSIPPI DRIVE
MUSCATINE IA 52763

ATTN: PHIL ALLEN

Client Sample ID:	Sample #1 Run 1	Sample ID By	Heartland Renewable Energy
Date Sampled:	N/A	Sample Taken At	Anhydro Test Unit Baltimore
Date Received:	Apr 3, 2008	Sample Taken By	Dave Augustine
Product Description:	Misc Solid		

SGS Minerals Sample ID: 491-0825434-001

		As Received	Dry	MAF
% Total Moisture	[ASTM D3302]	6 99		
% Ash	[ASTM D3174/D5142]	28.11	30 22	
% Volatile Matter	[ASTM D3175/D5142]	59.82	64 31	
% Fixed Carbon	[ASTM D3172/D5142]	5 08	5 47	
% Sulfur	[ASTM D4239 Method B]	0 81	0 87	
Gross Calorific Value	[ASTM D5865]	5612	6034	8647
% Carbon	[ASTM D5373]	35.04	37 67	
% Hydrogen	[ASTM D5373]	3.74	4.02	
% Nitrogen	[ASTM D5373]	1.99	2.14	
% Oxygen (by difference)	[ASTM D5373(Calc)]	23.33	25.08	

Analyte	Result	Method
ANALYSIS OF ASH		
Silicon dioxide	2.03 %	ASTM D4326
Aluminum oxide	0.19 %	ASTM D4326
Titanium dioxide	<0.01 %	ASTM D4326
Iron oxide	0.23 %	ASTM D4326
Calcium oxide	9.81 %	ASTM D4326
Magnesium oxide	5.57 %	ASTM D4326
Potassium oxide	39.67 %	ASTM D4326
Sodium oxide	2.16 %	ASTM D4326
Sulfur trioxide	7.00 %	ASTM D4326
Phosphorus pentoxide	0.77 %	ASTM D4326
Strontium oxide	0.02 %	ASTM D4326
Barium oxide	0.01 %	ASTM D4326
Manganese Dioxide	0.06 %	ASTM D4326
Undetermined	32.48 %	ASTM D4326
MAA Sum	67.52 %	ASTM D4326
MAA Basis	Dry s. u.	ASTM D4326
MAA Silica Value	11.51 %	ASTM D4326

Vanessa Chambliss

VANESSA_CHAMBLISS

SGS North America Inc. | Minerals Services Division
16130 Van Drunen Road South Holland IL 60473 t (708) 331-2900 f (708) 333-3060 www.sgs.com/minerals

Member of the SGS Group

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Analysis Report

April 21, 2008

HEARTLAND RENEWABLE ENERGY
407 W. MISSISSIPPI DRIVE
MUSCATINE IA 52763

ATTN: PHIL ALLEN

Client Sample ID:	Sample #1 Run 1	Sample ID By	Heartland Renewable Energy
Date Sampled:	N/A	Sample Taken At	Anhydro Test Unit Baltimore
Date Received:	Apr 3, 2008	Sample Taken By	Dave Augustine
Product Description:	Misc Solid		

SGS Minerals Sample ID: 491-0825434-001

Analyte	Result	Method
ANALYSIS OF ASH (continued)		
MAA Type of Ash	LIGNITIC s. u.	ASTM D4326
Fouling Index	2.16 %	ASTM D4326
FUSION TEMPERATURE OF ASH, OXIDIZING		
Initial Deformation	>2700 øF	ASTM D1857
Softening	>2700 øF	ASTM D1857
Hemispherical	>2700 øF	ASTM D1857
Fluid	>2700 øF	ASTM D1857
FUSION TEMPERATURE OF ASH, REDUCING		
Initial Deformation	2460 øF	ASTM D1857
Softening	>2700 øF	ASTM D1857
Hemispherical	>2700 øF	ASTM D1857
Fluid	>2700 øF	ASTM D1857

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Analysis Report

April 21, 2008

HEARTLAND RENEWABLE ENERGY
407 W. MISSISSIPPI DRIVE
MUSCATINE IA 52763

ATTN: PHIL ALLEN

Client Sample ID:	Sample #2 Run 5	Sample ID By	Heartland Renewable Energy
Date Sampled:	N/A	Sample Taken At	Anhydro Test Unit Baltimore
Date Received:	Apr 3, 2008	Sample Taken By	Dave Augustine
Product Description:	Misc Solid		

SGS Minerals Sample ID: 491-0825434-002

		As Received	Dry	MAF
% Total Moisture	[ASTM D3302]	4.61		
% Ash	[ASTM D3174/D5142]	29.55	30.98	
% Volatile Matter	[ASTM D3175/D5142]	61.72	64.71	
% Fixed Carbon	[ASTM D3172/D5142]	4.12	4.31	
% Sulfur	[ASTM D4239 Method B]	0.64	0.67	
Gross Calorific Value	[ASTM D5865]	5651	5924	8583
% Carbon	[ASTM D5373]	35.40	37.11	
% Hydrogen	[ASTM D5373]	3.99	4.18	
% Nitrogen	[ASTM D5373]	2.01	2.11	
% Oxygen (by difference)	[ASTM D5373(Calc)]	23.80	24.95	

Analyte	Result	Method
ANALYSIS OF ASH		
Silicon dioxide	1.93 %	ASTM D4326
Aluminum oxide	0.11 %	ASTM D4326
Titanium dioxide	<0.01 %	ASTM D4326
Iron oxide	0.23 %	ASTM D4326
Calcium oxide	9.96 %	ASTM D4326
Magnesium oxide	5.67 %	ASTM D4326
Potassium oxide	39.53 %	ASTM D4326
Sodium oxide	2.07 %	ASTM D4326
Sulfur trioxide	6.65 %	ASTM D4326
Phosphorus pentoxide	0.76 %	ASTM D4326
Strontium oxide	0.02 %	ASTM D4326
Barium oxide	0.01 %	ASTM D4326
Manganese Dioxide	0.06 %	ASTM D4326
Undetermined	33.00 %	ASTM D4326
MAA Sum	67.00 %	ASTM D4326
MAA Basis	Dry s. u.	ASTM D4326
MAA Silica Value	10.85 %	ASTM D4326

Vanessa Chambliss

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SGS

Analysis Report

April 21, 2008

HEARTLAND RENEWABLE ENERGY
407 W. MISSISSIPPI DRIVE
MUSCATINE IA 52763

ATTN: PHIL ALLEN

Client Sample ID:	Sample #2 Run 5	Sample ID By	Heartland Renewable Energy
Date Sampled:	N/A	Sample Taken At	Anhydro Test Unit Baltimore
Date Received:	Apr 3, 2008	Sample Taken By	Dave Augustine
Product Description:	Misc Solid		

SGS Minerals Sample ID: 491-0825434-002

Analyte	Result	Method
ANALYSIS OF ASH (continued)		
MAA Type of Ash	LIGNITIC s. u.	ASTM D4326
Fouling Index	2.07 %	ASTM D4326
FUSION TEMPERATURE OF ASH, OXIDIZING		
Initial Deformation	>2700 øF	ASTM D1857
Softening	>2700 øF	ASTM D1857
Hemispherical	>2700 øF	ASTM D1857
Fluid	>2700 øF	ASTM D1857
FUSION TEMPERATURE OF ASH, REDUCING		
Initial Deformation	2495 øF	ASTM D1857
Softening	>2700 øF	ASTM D1857
Hemispherical	>2700 øF	ASTM D1857
Fluid	>2700 øF	ASTM D1857

Vanessa Chambliss

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Appendix C

Spray Drying Report

CUSTOMER REPORT

CLIENT: **Stanley Consultants / Heartland Renewable Energy**
CONTACT: **Doug Einck**
AVEKA MO #: **7789**
DATE: **June 10, 2010**

SUMMARY AND OBJECTIVES:

Stanley Consulting is working for Heartland Renewable Energy to help them explore the feasibility of using dry solids of a liquid designated as "clarified wine" as fuel. Aveka has spray dried the "clarified wine" liquid into a dry powder, which will be tested by Stanley Consultants.

MATERIALS:

"Clarified Wine" (provided by Heartland)

PROCEDURE:

The "clarified wine" was processed in Aveka's Mobile Miner lab scale spray drier. Run conditions were determined from the previous Anhydro test runs of the material. From the previous Anhydro runs it was determined that the outlet temperature was set between 105-120º C. As a result of the high outlet temperature, the inlet temperature had to be set to 480º C. Also the feed rate was maintained between 36-41 g/minute throughout the process.

Variations in the sample are a result in different atomizing air pressures, which result in different particle sizes. Sample Lot# 10176 was processed with an atomization air pressure of 60 psi. To increase yield the air pressure was lowered to 10 psi. The lower air pressure created a larger particle which increased yield. The sample sprayed at 10 psi was titled Lot# 10179.

After the runs, material that had collected on the walls of the drier was removed by being scraped from the walls. This material was titled "Scrape Down" Lot# 10176 and "Scrape Down" Lot# 10179, corresponding to the runs.

For "Scrape Down" Lot# 10176 the spray drier was heated to 200º C and run for 20 minutes due to the material absorption of moisture. The high temperate caused a dark crunchy material. For "Scrape Down" Lot# 10179 a lower temperature of 120º C was used for 30 minutes and resulted in less darkening of the material.

RESULTS AND DISCUSSION:

Along with the product material, “Scrape Down” material was also sent to Stanley Consultants. This is material that had collected to the walls of the spray drier. During the first run it had been noticed that a significant amount of material was clinging to the walls of the spray drier during the process. In order to remove this material, the drier was heated and then scraped off.

In between runs, material which had been stuck to the surface of the interior of the drier was allowed to sit inside the drier overnight. In the morning, the material had changed to a dark brown color and had become very sticky. It was apparent that the material absorbs moisture from the air. This is most likely due to the residual sugars remaining in the “clarified wine” material. In order to prove the concept, 10g of dried material was placed in a “green house” like high humidity containers. After two hours, browning of the material could be noticed and after five hours, much of the sample had become sticky. It is evident that the dried material will need to be stored, shipped and handled in low humidity areas.

Attached are images of the experiment. (Reference Heartland-Stanley 7789 Images)

LIST OF SAMPLES SHIPPED TO CUSTOMER:

Lot # 10176, Spray Dried “Clarified Wine”: 1000g
Lot # 10179, Spray Dried “Clarified Wine”: 504g
Lot # 10176, Spray Dried “Clarified Wine” Scrape Down: 142g
Lot # 10179, Spray Dried “Clarified Wine” Scrape Down: 263g

SUGGESTIONS FOR FUTURE WORK

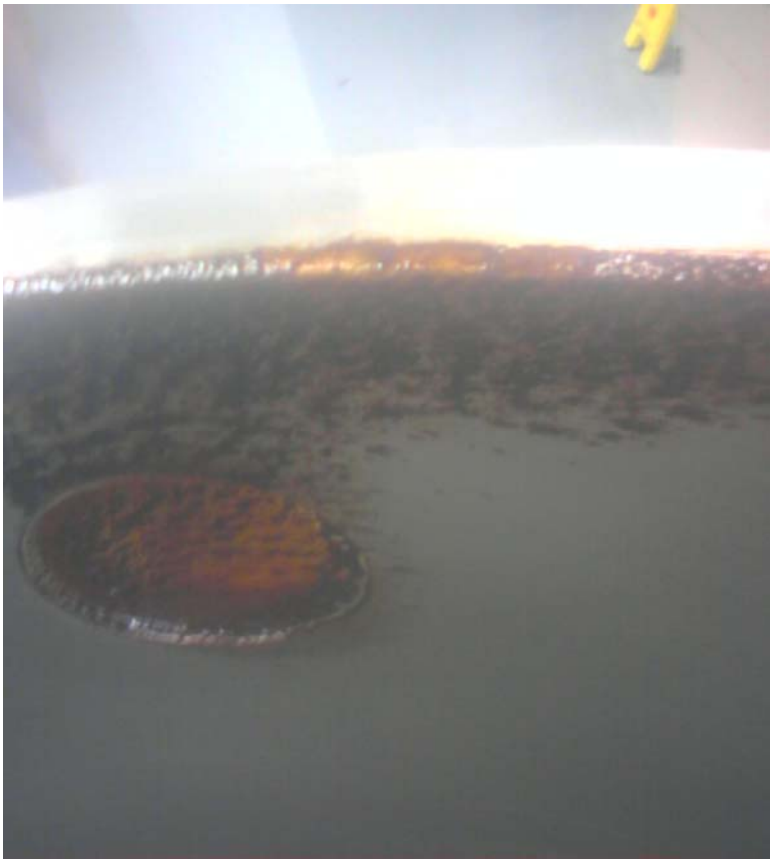
Allow Stanley Consultants to evaluate these materials so see if the material proves to be a valuable fuel source, then additional work is recommended in order to optimize percent yield.

SUBMITTED BY: Todd Naranjo, Associate Engineer, AVEKA, Inc.

IMAGES

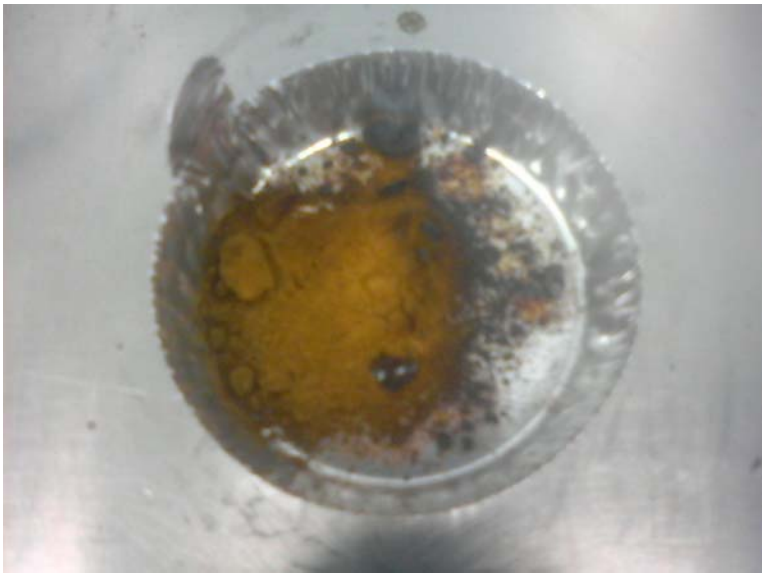
CLIENT: Stanley Consultants / Heartland Renewable Energy
CONTACT: Doug Einck
AVEKA MO #: 7789
DATE: June 10, 2010

(Reference Heartland-Stanley 7789 AVEKA Project Report)



1. **Example of sticky material on the edge of the spray drier.**

2. **10g of product material collected and recently placed in a high humidity environment**



3. **After 2 hours in high humidity dark brown material can be observed on the edge of the sample**

4. **After 5 hours in high humidity, the sample has completely turned dark brown and is stick to the touch. Also the material seems to be massing together.**

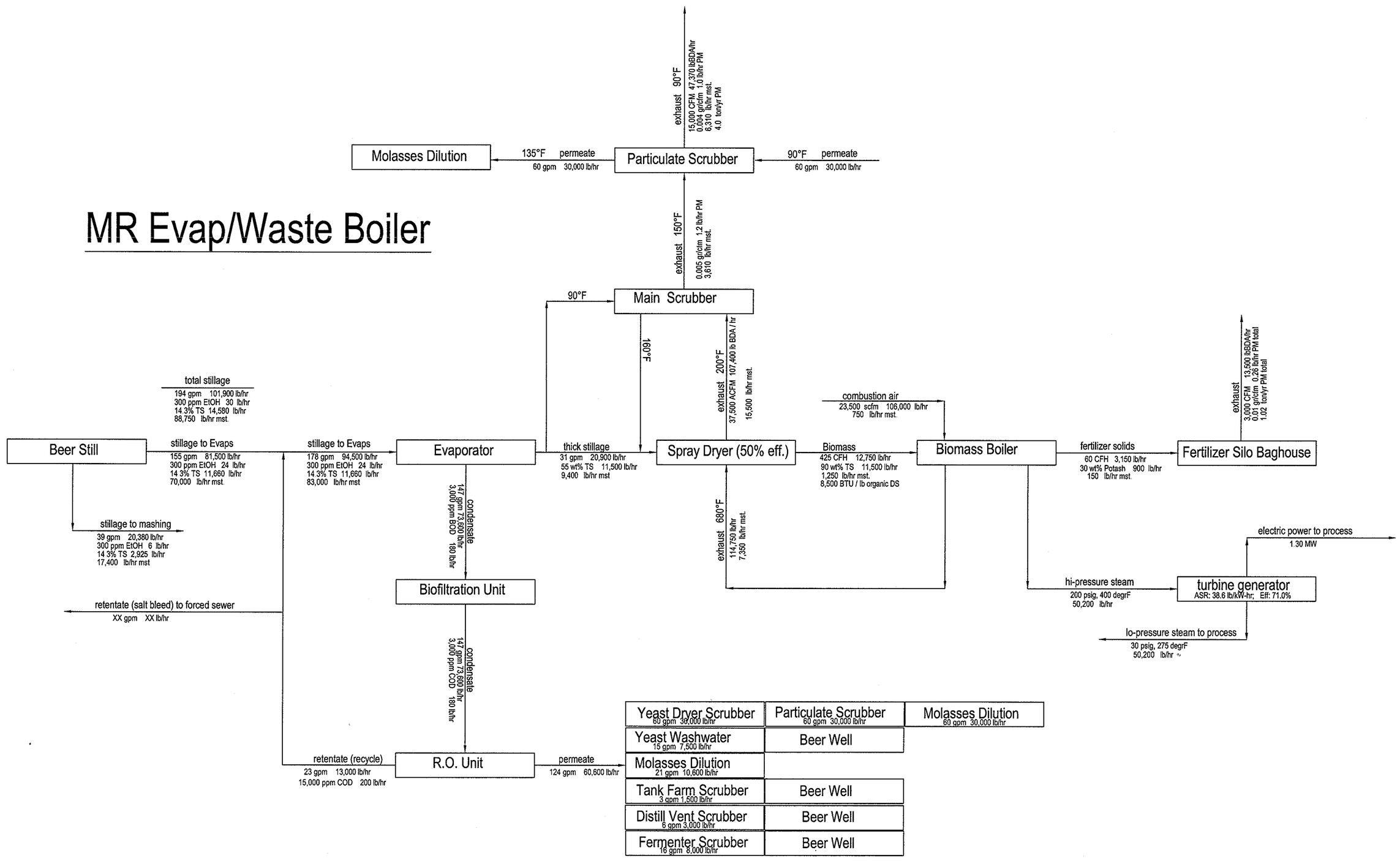
5. **Example of a sample allowed to be exposed to normal room conditions overnight.**

SUBMITTED BY: Todd Naranjo, Associate Engineer, AVEKA, Inc.

Appendix D

Plant Mass Balance

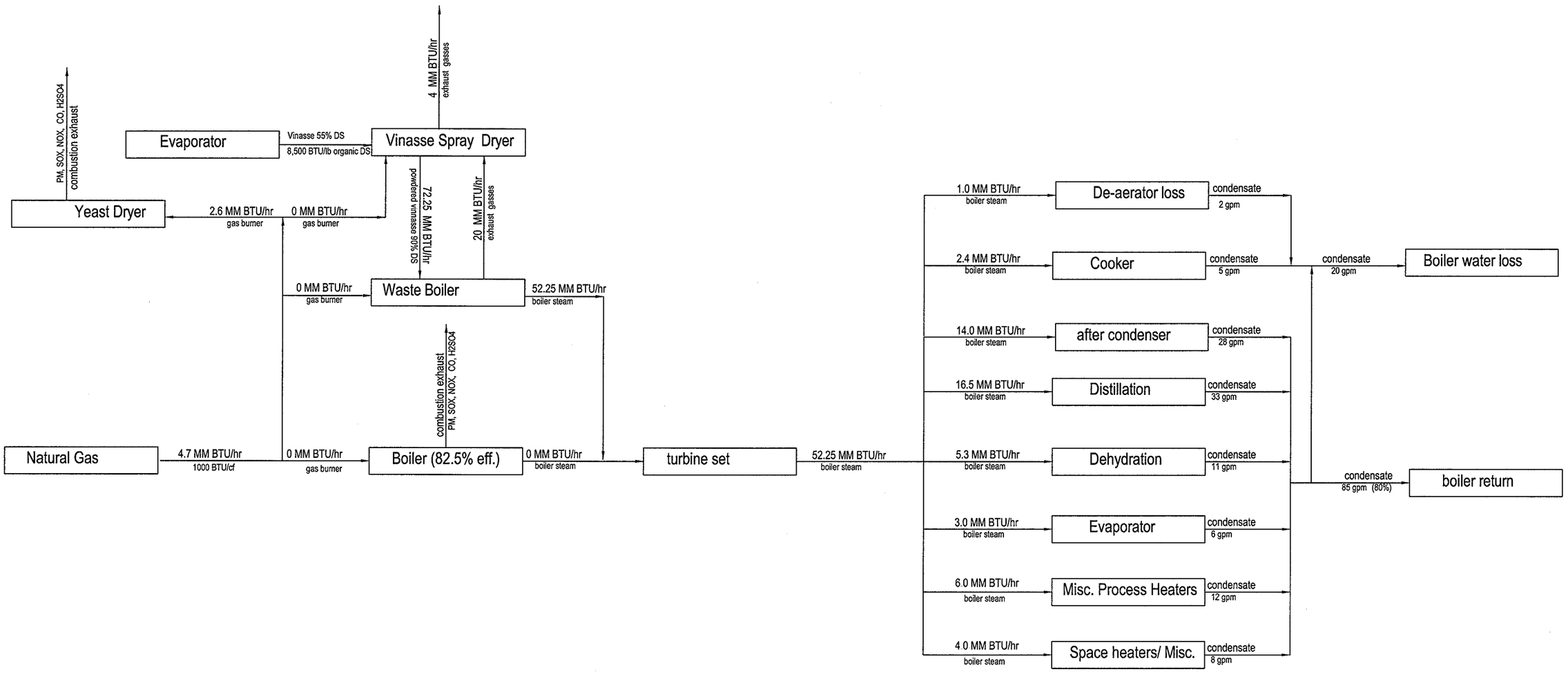
MR Evap/Waste Boiler



Appendix E

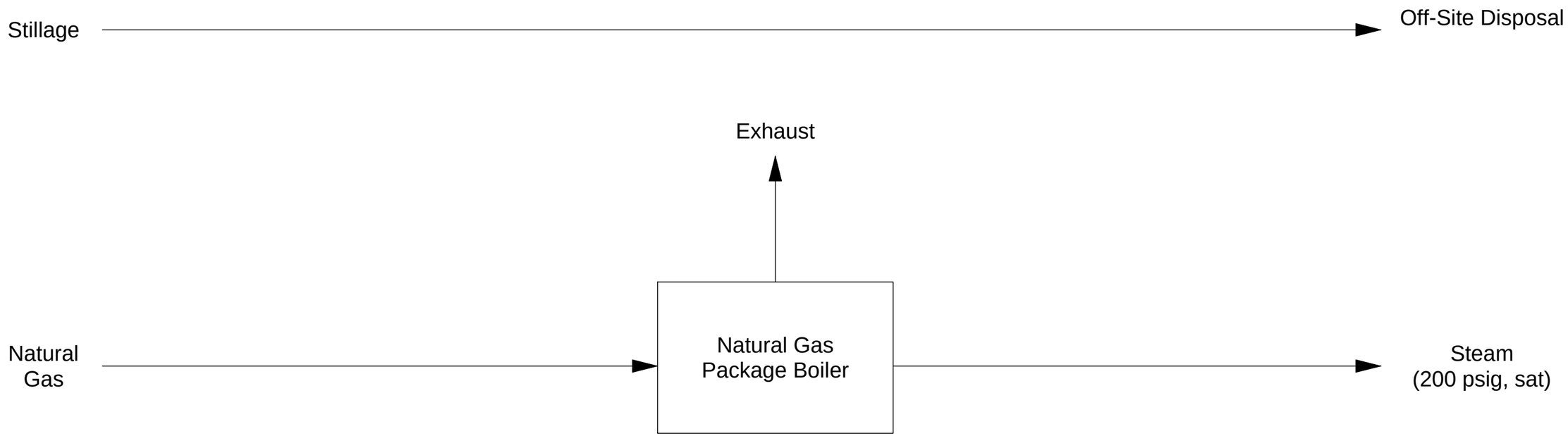
Plant Energy Balance

MR Evap/Waste Boiler

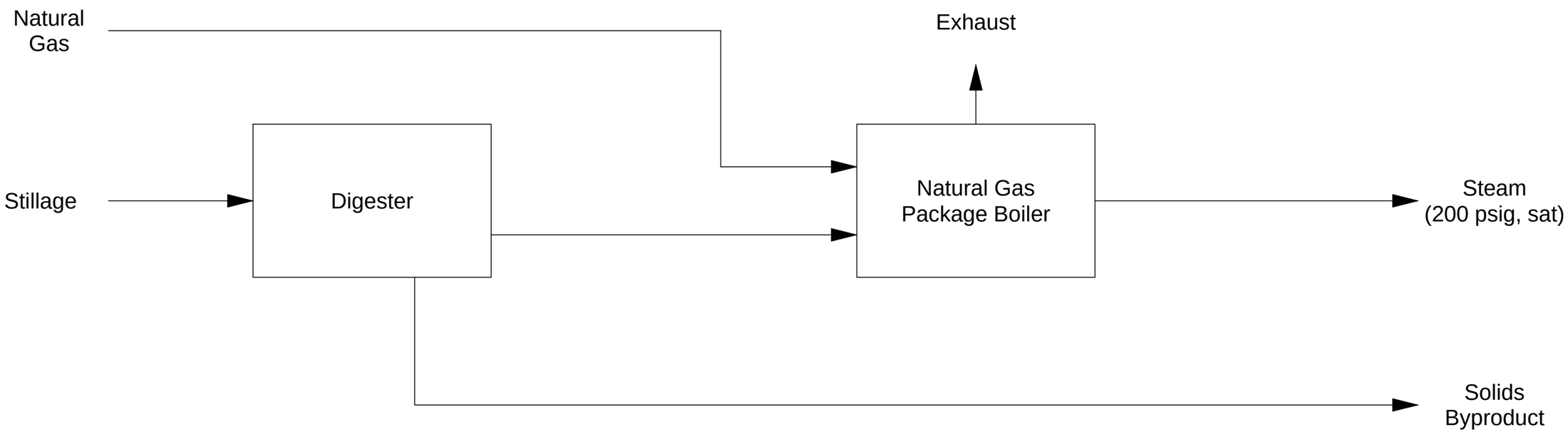


Appendix F

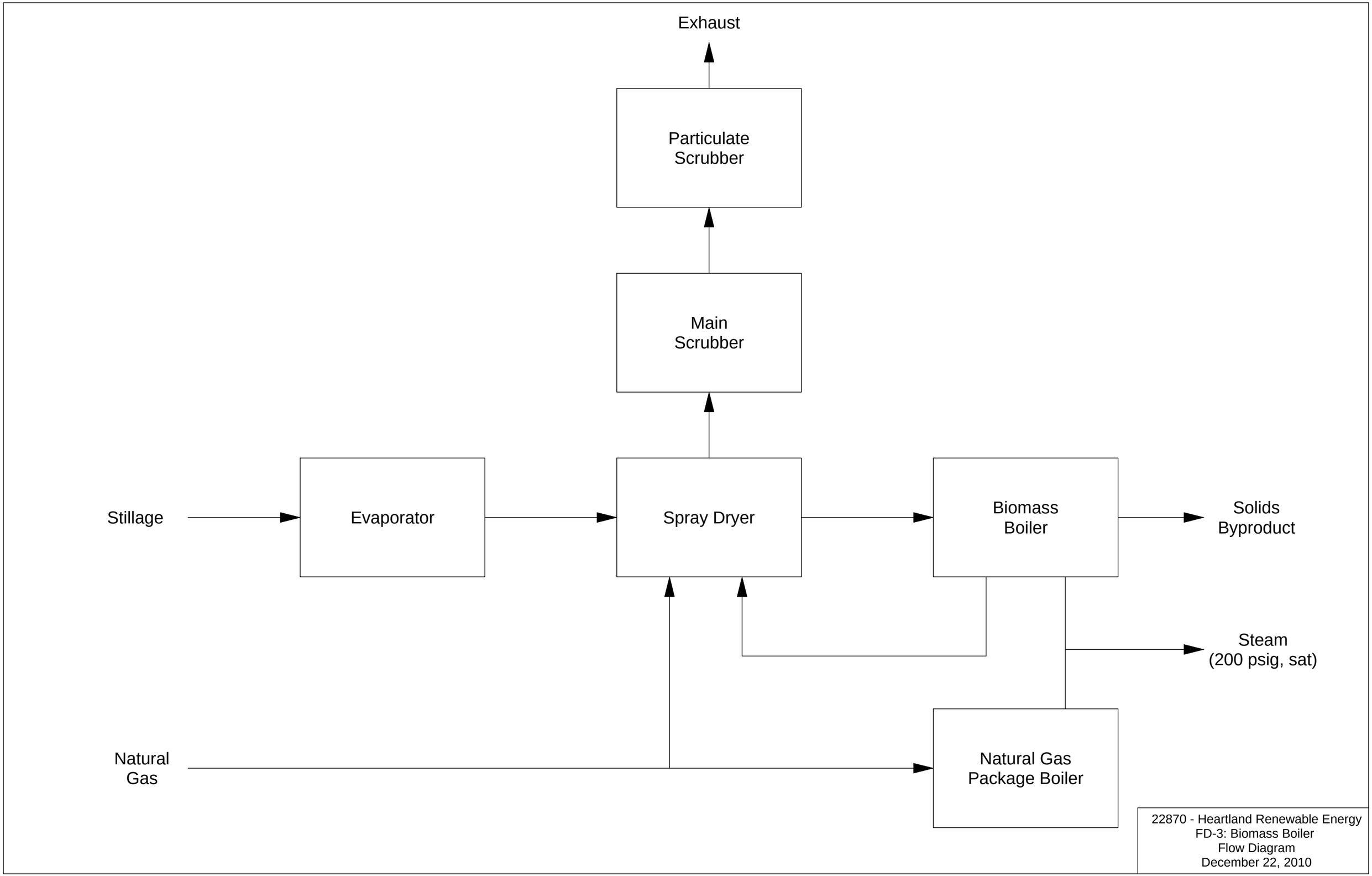
Flow Diagrams



22870 - Heartland Renewable Energy
FD-1: Natural Gas Package Boiler
Flow Diagram
December 22, 2010



22870 - Heartland Renewable Energy
FD-2: Anaerobic Digester
Flow Diagram
December 22, 2010


Exhaust
Particulate Scrubber
Main Scrubber
Stillage
Evaporator
Spray Dryer
Biomass Boiler
Solids Byproduct
Steam (200 psig, sat)
Natural Gas
Natural Gas Package Boiler
22870 - Heartland Renewable Energy
FD-3: Biomass Boiler
Flow Diagram
December 22, 2010

Appendix G

Biomass Boiler Cost Estimates

Project 22870.01 - Biomass Boiler Study
Heartland Renewable Energy
Captial Cost Estimate
December 22, 2010

Alternative 2: Hurst Biomass Boiler	Equipment	Installation	Total
Biomass boiler	$4,168,000	$1,042,000	$5,210,000
Economizer	Incl.	Incl.	Incl.
FD and ID fans	Incl.	Incl.	Incl.
Backup natural gas burners	$154,000	$38,500	$192,500
Metering bins and fuel feed	Incl.	Incl.	Incl.
Bed media storage system	Not Req'd	Not Req'd	Not Req'd
Ash storage	$300,000	$75,000	$375,000
Boiler control system	Incl.	Incl.	Incl.
Tri-Mer Ultra-Clean Multi-Pollutant Control system	$1,750,000	$437,500	$2,187,500
100' stack with CEMs	$200,000	$50,000	$250,000
Evaporator	$1,950,000	$487,500	$2,437,500
Spray Dryer	$3,000,000	$750,000	$3,750,000
Main scrubber	Incl.	Incl.	$500,000
Particulate scrubber	Incl.	Incl.	Incl.
Package boiler - natural gas	Incl.	Incl.	$610,000
subtotal	$11,522,000	$2,880,500	$15,512,500
General Contractor Overhead and Profit (30% on installation only)		$864,150	$864,150
subtotal	$11,522,000	$3,744,650	$16,376,650
Undeveloped design details (10% - major equipment)			$1,637,665
Direct cost			$18,014,315
Engineering, permitting, and administrative (8.5%)			$1,531,217
Contingency (20%)			$3,602,863
Total			**$23,100,000**

Project 22870.01 - Biomass Boiler Study
Heartland Renewable Energy
Captial Cost Estimate
December 22, 2010

Alternative 3: EPI (BFB Gasifier)	Equipment	Installation	Total
Biomass boiler	$6,723,000	$2,353,050	$9,076,050
Economizer	Incl.	Incl.	Incl.
FD and ID fans	Incl.	Incl.	Incl.
Backup natural gas burners	Incl.	Incl.	Incl.
Metering bins and fuel feed	Incl.	Incl.	Incl.
Bed media storage system	Incl.	Incl.	Incl.
Ash storage	Incl.	Incl.	Incl.
Boiler control system	Incl.	Incl.	Incl.
SNCR	Incl.	Incl.	Incl.
Limestone injection	Incl.	Incl.	Incl.
Dry scrubber	Incl.	Incl.	Incl.
Baghouse	Incl.	Incl.	Incl.
Tri-Mer Ultra-Clean system	Not Req'd	Not Req'd	Not Req'd
100' stack with CEMs	Incl.	Incl.	Incl.
Evaporator	$1,950,000	$487,500	$2,437,500
Spray Dryer	$3,000,000	$750,000	$3,750,000
Main scrubber	Incl.	Incl.	$500,000
Particulate scrubber	Incl.	Incl.	Incl.
Package boiler - natural gas	Incl.	Incl.	$570,000
subtotal	$11,673,000	$3,590,550	$16,333,550
General Contractor Overhead and Profit (30% on installation only)		$1,077,165	$1,077,165
subtotal	$11,673,000	$4,667,715	$17,410,715
Undeveloped design details (10% - major equipment)			$1,741,072
Direct cost			$19,151,787
Engineering, permitting, and administrative (8.5%)			$1,627,902
Contingency (20%)			$3,830,357
Total			**$24,600,000**

Appendix H

Life Cycle Cost Analysis

ECONOMIC ANALYSIS: HEARTLAND RENEWABLE ENERGY - BIOMASS BOILER STUDY

Escalation Rate Parameters		Other Parameters		
		Discount Rate:	5.00%	
Natural gas escalation:	1.10%	Cost of Electricity:	$0.065	/kWh
Electricity Rate Escalation:	2.60%	Natural Gas Cost:	$6.47	$/mmBTU
O&M Escalation:	4.00%	t Thermal Needs (200 psig, sat steam)	67000	lb/hr
Byproduct Disposal Escalation:	3.00%	Plant Capacity Factor:	98%	
Tax Rate Escalation:	2.00%	Biomass Feed Rate to the Boiler:	12750	lb/hr
		Biomass Heating Value:	5507	BTU/lb
		Biomass Ash Content:	29.76%	
		Hurst Boiler Efficiency:	70%	
Capital Costs		BFB Gasifier Boiler Efficiency:	72%	
Base Case - Natural Gas Package Boiler:	$3,000,000	Natural Gas Boiler Efficiency:	82%	
Alternative 1 - Digester:	$16,600,000	; Package Boiler Power Requirements	120	kW
Alternative 2 - Hurst Biomass Boiler:	$23,100,000	)igester Auxiliary Power Requirements	150	kW
Alternative 3 - EPI (BFB Gasifier):	$24,600,000	Hurst Auxiliary Power Requirements:	730	kW
		BFB Auxiliary Power Requirements:	900	kW
		Stillage Disposal Cost:	$0.00	$/kgal
		Compost Disposal Cost (Sales):	$0.00	$/ton
		Solid Waste Disposal Cost:	$15.00	$/ton
		Maint. / Repair Cost:	2.00%	% of capital cost
		Insurance Cost:	0.5%	% of capital cost

PROJECT SUMMARY	Base Case: NG Package Boiler	Alternative 1: Digester	Alternative 2: Hurst Boiler	Alternative 3: EPI BFB Gasifier
Capital Cost	$3,000,000	$16,600,000	$23,100,000	$24,600,000
10 Year Cost	$54,802,738	$50,480,076	$58,305,641	$60,461,474
15 Year Cost	$83,051,653	$69,453,125	$78,657,145	$81,283,494
20 Year Cost	$113,007,342	$89,991,128	$101,185,661	$104,401,971
30 Year Cost	$178,522,822	$136,551,531	$154,084,640	$158,933,091
10 Year Present Value	$42,815,314	$42,605,274	$50,077,232	$52,073,230
15 Year Present Value	$57,814,897	$52,675,732	$60,874,695	$63,119,679
20 Year Present Value	$70,277,434	$61,216,597	$70,239,188	$72,728,842
30 Year Present Value	$89,252,903	$74,674,737	$85,500,837	$88,457,641
Payback (Years)	Base Case	9.8	19.9	26.6

Base Case: Natural Gas Package Boiler

Number of Years	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Project Cost Beginning of Year	**$3,000,000**																			
Biomass Fuel Cos	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Natural Gas Cost	$4,773,113	$4,825,617	$4,878,699	$4,932,365	$4,986,621	$5,041,474	$5,096,930	$5,152,996	$5,209,679	$5,266,986	$5,324,922	$5,383,497	$5,442,715	$5,502,585	$5,563,113	$5,624,308	$5,686,175	$5,748,723	$5,811,959	$5,875,890
Auxiliary Power Cos	$66,961	$68,702	$70,489	$72,321	$74,202	$76,131	$78,110	$80,141	$82,225	$84,363	$86,556	$88,807	$91,116	$93,485	$95,915	$98,409	$100,968	$103,593	$106,286	$109,050
Maintenance/Repair Cos	$60,000	$62,400	$64,896	$67,492	$70,192	$72,999	$75,919	$78,956	$82,114	$85,399	$88,815	$92,367	$96,062	$99,904	$103,901	$108,057	$112,379	$116,874	$121,549	$126,411
Byproduct Disposal Cost (Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Taxes/Insurance Cos	$15,000	$15,300	$15,606	$15,918	$16,236	$16,561	$16,892	$17,230	$17,575	$17,926	$18,285	$18,651	$19,024	$19,404	$19,792	$20,188	$20,592	$21,004	$21,424	$21,852
Annual Tota	**$7,915,075**	**$4,972,020**	**$5,029,690**	**$5,088,096**	**$5,147,251**	**$5,207,165**	**$5,267,852**	**$5,329,324**	**$5,391,593**	**$5,454,673**	**$5,518,578**	**$5,583,321**	**$5,648,916**	**$5,715,378**	**$5,782,721**	**$5,850,961**	**$5,920,113**	**$5,990,193**	**$6,061,218**	**$6,133,203**
Running Tota	**$7,915,075**	**$12,887,094**	**$17,916,784**	**$23,004,880**	**$28,152,131**	**$33,359,296**	**$38,627,148**	**$43,956,471**	**$49,348,065**	**$54,802,738**	**$60,321,316**	**$65,904,637**	**$71,553,553**	**$77,268,931**	**$83,051,653**	**$88,902,614**	**$94,822,727**	**$100,812,921**	**$106,874,138**	**$113,007,342**
Present Value Analysis																				
Present Value to Jan 1, 2014	**$7,681,023**	**$4,509,769**	**$4,344,835**	**$4,185,989**	**$4,033,006**	**$3,885,667**	**$3,743,764**	**$3,607,096**	**$3,475,469**	**$3,348,696**	**$3,226,598**	**$3,109,002**	**$2,995,741**	**$2,886,654**	**$2,781,588**	**$2,680,393**	**$2,582,926**	**$2,489,049**	**$2,398,630**	**$2,311,540**
Running Tota	**7,681,023**	**12,190,792**	**16,535,627**	**20,721,616**	**24,754,622**	**28,640,289**	**32,384,053**	**35,991,149**	**39,466,618**	**42,815,314**	**46,041,912**	**49,150,914**	**52,146,655**	**55,033,310**	**57,814,897**	**60,495,290**	**63,078,216**	**65,567,265**	**67,965,895**	**70,277,434**
Total 10-Year Present Value	**$42,815,314**																			
Total 15-Year Present Value	**$57,814,897**																			
Total 20-Year Present Value	**$70,277,434**																			
Total 30-Year Present Value	**$89,252,903**																			

Alternative 1: Digester

Number of Years	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Project Cost Beginning of Year	**$16,600,000**																			
Biomass Fuel Cos	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Natural Gas Cost	$2,668,286	$2,697,637	$2,727,311	$2,757,312	$2,787,642	$2,818,306	$2,849,308	$2,880,650	$2,912,337	$2,944,373	$2,976,761	$3,009,505	$3,042,610	$3,076,079	$3,109,916	$3,144,125	$3,178,710	$3,213,676	$3,249,026	$3,284,766
Auxiliary Power Cos	$83,702	$85,878	$88,111	$90,402	$92,752	$95,164	$97,638	$100,177	$102,781	$105,454	$108,195	$111,008	$113,895	$116,856	$119,894	$123,011	$126,210	$129,491	$132,858	$136,312
Maintenance/Repair Cos	$332,000	$345,280	$359,091	$373,455	$388,393	$403,929	$420,086	$436,889	$454,365	$472,540	$491,441	$511,099	$531,543	$552,804	$574,917	$597,913	$621,830	$646,703	$672,571	$699,474
Byproduct Disposal Cost (Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Taxes/Insurance Cos	$83,000	$84,660	$86,353	$88,080	$89,842	$91,639	$93,471	$95,341	$97,248	$99,193	$101,177	$103,200	$105,264	$107,369	$109,517	$111,707	$113,941	$116,220	$118,544	$120,915
Annual Tota	**$19,766,988**	**$3,213,455**	**$3,260,867**	**$3,309,249**	**$3,358,629**	**$3,409,038**	**$3,460,503**	**$3,513,057**	**$3,566,731**	**$3,621,559**	**$3,677,574**	**$3,734,813**	**$3,793,311**	**$3,853,108**	**$3,914,243**	**$3,976,756**	**$4,040,691**	**$4,106,090**	**$4,173,000**	**$4,241,467**
Running Total	**$19,766,988**	**$22,980,444**	**$26,241,310**	**$29,550,559**	**$32,909,188**	**$36,318,226**	**$39,778,729**	**$43,291,786**	**$46,858,517**	**$50,480,076**	**$54,157,650**	**$57,892,462**	**$61,685,774**	**$65,538,882**	**$69,453,125**	**$73,429,881**	**$77,470,572**	**$81,576,662**	**$85,749,661**	**$89,991,128**
Present Value Analysis																				
Present Value to Jan 1, 2014	**$19,616,179**	**$2,914,699**	**$2,816,859**	**$2,722,527**	**$2,631,574**	**$2,543,876**	**$2,459,315**	**$2,377,775**	**$2,299,147**	**$2,223,323**	**$2,150,201**	**$2,079,683**	**$2,011,674**	**$1,946,082**	**$1,882,818**	**$1,821,798**	**$1,762,940**	**$1,706,165**	**$1,651,398**	**$1,598,564**
Running Tota	**19,616,179**	**22,530,878**	**25,347,737**	**28,070,264**	**30,701,838**	**33,245,715**	**35,705,030**	**38,082,805**	**40,381,951**	**42,605,274**	**44,755,476**	**46,835,159**	**48,846,833**	**50,792,915**	**52,675,732**	**54,497,530**	**56,260,470**	**57,966,635**	**59,618,033**	**61,216,597**
Total 10-Year Present Value	**$42,605,274**																			
Total 15-Year Present Value	**$52,675,732**																			
Total 20-Year Present Value	**$61,216,597**																			
Total 30-Year Present Value	**$74,674,737**																			
Comparison with Base Case - NG Package Boiler																				
Capital cost difference	**$13,600,000**																			
Operating Savings/(Costs)	**1,664,844**	**1,595,070**	**1,527,976**	**1,463,462**	**1,401,432**	**1,341,790**	**1,284,449**	**1,229,321**	**1,176,322**	**1,125,373**	**1,076,397**	**1,029,319**	**984,067**	**940,573**	**898,770**	**858,595**	**819,986**	**782,884**	**747,232**	**712,975**
Running Tota	**1,664,844**	**3,259,914**	**4,787,890**	**6,251,352**	**7,652,784**	**8,994,574**	**10,279,023**	**11,508,344**	**12,684,666**	**13,810,040**	**14,886,437**	**15,915,755**	**16,899,822**	**17,840,395**	**18,739,165**	**19,597,760**	**20,417,746**	**21,200,630**	**21,947,862**	**22,660,837**
Time Value Payback, years	**9.8**																			
Payback Calculation										9.8										

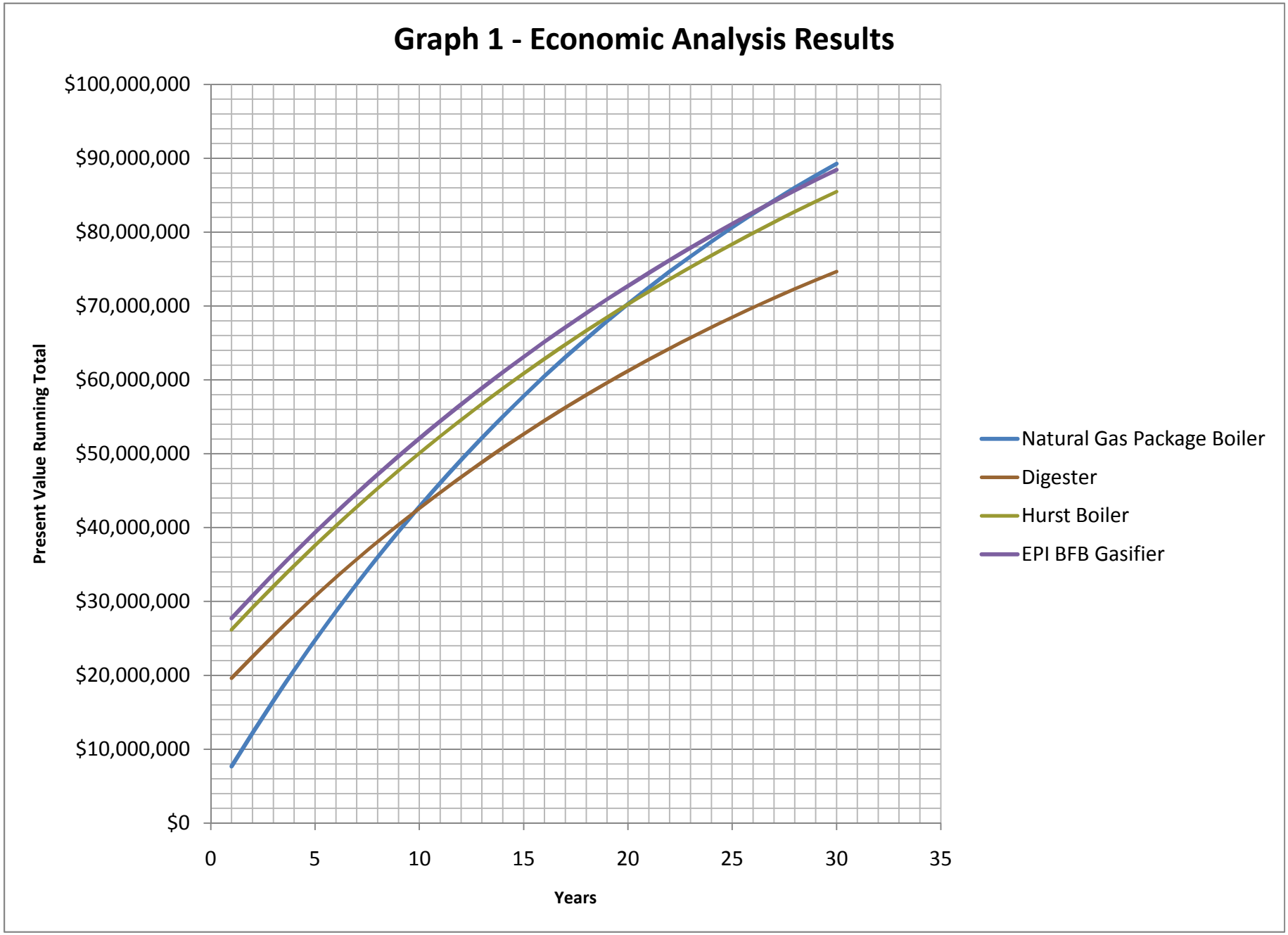
Alternative 2: Hurst Biomass Boiler

Number of Years	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Project Cost Beginning of Year	**$23,100,000**																			
Biomass Fuel Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Natural Gas Cost (Note 1)	$1,998,967	$2,020,956	$2,043,186	$2,065,661	$2,088,383	$2,111,356	$2,134,580	$2,158,061	$2,181,800	$2,205,799	$2,230,063	$2,254,594	$2,279,394	$2,304,468	$2,329,817	$2,355,445	$2,381,355	$2,407,550	$2,434,033	$2,460,807
Auxiliary Power Cost	$407,349	$417,940	$428,806	$439,955	$451,394	$463,130	$475,172	$487,526	$500,202	$513,207	$526,550	$540,241	$554,287	$568,699	$583,485	$598,655	$614,220	$630,190	$646,575	$663,386
Maintenance/Repair Cost	$462,000	$480,480	$499,699	$519,687	$540,475	$562,094	$584,577	$607,960	$632,279	$657,570	$683,873	$711,228	$739,677	$769,264	$800,035	$832,036	$865,317	$899,930	$935,927	$973,364
Byproduct Disposal Cost (Sales)	$244,306	$251,635	$259,184	$266,960	$274,969	$283,218	$291,714	$300,466	$309,480	$318,764	$328,327	$338,177	$348,322	$358,772	$369,535	$380,621	$392,040	$403,801	$415,915	$428,392
Taxes/Insurance Cost	$115,500	$117,810	$120,166	$122,570	$125,021	$127,521	$130,072	$132,673	$135,327	$138,033	$140,794	$143,610	$146,482	$149,412	$152,400	$155,448	$158,557	$161,728	$164,962	$168,262
Annual Total	**$26,328,122**	**$3,288,821**	**$3,351,042**	**$3,414,833**	**$3,480,242**	**$3,547,319**	**$3,616,116**	**$3,686,687**	**$3,759,087**	**$3,833,374**	**$3,909,607**	**$3,987,849**	**$4,068,162**	**$4,150,614**	**$4,235,271**	**$4,322,205**	**$4,411,489**	**$4,503,199**	**$4,597,412**	**$4,694,211**
Running Total	**$26,328,122**	**$29,616,943**	**$32,967,985**	**$36,382,818**	**$39,863,060**	**$43,410,378**	**$47,026,494**	**$50,713,181**	**$54,472,267**	**$58,305,641**	**$62,215,249**	**$66,203,098**	**$70,271,260**	**$74,421,874**	**$78,657,145**	**$82,979,350**	**$87,390,839**	**$91,894,037**	**$96,491,450**	**$101,185,661**
Present Value Analysis																				
Present Value to Jan 1, 2014	**$26,174,402**	**$2,983,057**	**$2,894,756**	**$2,809,392**	**$2,726,861**	**$2,647,064**	**$2,569,906**	**$2,495,295**	**$2,423,141**	**$2,353,359**	**$2,285,867**	**$2,220,584**	**$2,157,433**	**$2,096,342**	**$2,037,238**	**$1,980,052**	**$1,924,718**	**$1,871,172**	**$1,819,352**	**$1,769,199**
Running Total	**26,174,402**	**29,157,459**	**32,052,215**	**34,861,607**	**37,588,468**	**40,235,531**	**42,805,437**	**45,300,732**	**47,723,873**	**50,077,232**	**52,363,098**	**54,583,682**	**56,741,115**	**58,837,457**	**60,874,695**	**62,854,747**	**64,779,465**	**66,650,637**	**68,469,989**	**70,239,188**
Total 10-Year Present Value	**$50,077,232**																			
Total 15-Year Present Value	**$60,874,695**																			
Total 20-Year Present Value	**$70,239,188**																			
Total 30-Year Present Value	**$85,500,837**																			
Comparison with Base Case - NG Package Boiler																				
Capital cost difference	**$20,100,000**																			
Operating Savings/(Costs)	**1,606,622**	**1,526,711**	**1,450,079**	**1,376,598**	**1,306,145**	**1,238,603**	**1,173,858**	**1,111,801**	**1,052,328**	**995,337**	**940,732**	**888,419**	**838,307**	**790,312**	**744,350**	**700,341**	**658,208**	**617,877**	**579,278**	**542,341**
Running Total	**1,606,622**	**3,133,333**	**4,583,412**	**5,960,009**	**7,266,154**	**8,504,757**	**9,678,615**	**10,790,417**	**11,842,745**	**12,838,082**	**13,778,814**	**14,667,232**	**15,505,540**	**16,295,852**	**17,040,202**	**17,740,543**	**18,398,751**	**19,016,628**	**19,595,906**	**20,138,247**
Time Value Payback, years	**19.9**																			
Payback Calculation																				19.9

Alternative 3: EPI (BFB Gasifier)

Number of Years	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Project Cost Beginning of Year	**$24,600,000**																			
Biomass Fuel Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Natural Gas Cost (Note 1)	$1,917,696	$1,938,791	$1,960,118	$1,981,679	$2,003,477	$2,025,516	$2,047,796	$2,070,322	$2,093,096	$2,116,120	$2,139,397	$2,162,930	$2,186,723	$2,210,776	$2,235,095	$2,259,681	$2,284,538	$2,309,667	$2,335,074	$2,360,760
Auxiliary Power Cost	$502,211	$515,268	$528,665	$542,411	$556,513	$570,983	$585,828	$601,060	$616,687	$632,721	$649,172	$666,050	$683,368	$701,135	$719,365	$738,068	$757,258	$776,947	$797,147	$817,873
Maintenance/Repair Cost	$492,000	$511,680	$532,147	$553,433	$575,570	$598,593	$622,537	$647,438	$673,336	$700,269	$728,280	$757,411	$787,708	$819,216	$851,985	$886,064	$921,507	$958,367	$996,702	$1,036,570
Byproduct Disposal Cost (Sales)	$244,306	$251,635	$259,184	$266,960	$274,969	$283,218	$291,714	$300,466	$309,480	$318,764	$328,327	$338,177	$348,322	$358,772	$369,535	$380,621	$392,040	$403,801	$415,915	$428,392
Taxes/Insurance Cost	$123,000	$125,460	$127,969	$130,529	$133,139	$135,802	$138,518	$141,288	$144,114	$146,996	$149,936	$152,935	$155,994	$159,114	$162,296	$165,542	$168,853	$172,230	$175,674	$179,188
Annual Total	**$27,879,213**	**$3,342,835**	**$3,408,084**	**$3,475,011**	**$3,543,669**	**$3,614,111**	**$3,686,394**	**$3,760,574**	**$3,836,713**	**$3,914,871**	**$3,995,112**	**$4,077,504**	**$4,162,114**	**$4,249,013**	**$4,338,275**	**$4,429,976**	**$4,524,195**	**$4,621,012**	**$4,720,512**	**$4,822,783**
Running Total	**$27,879,213**	**$31,222,048**	**$34,630,132**	**$38,105,143**	**$41,648,812**	**$45,262,923**	**$48,949,317**	**$52,709,891**	**$56,546,604**	**$60,461,474**	**$64,456,587**	**$68,534,091**	**$72,696,205**	**$76,945,218**	**$81,283,494**	**$85,713,470**	**$90,237,665**	**$94,858,676**	**$99,579,189**	**$104,401,971**
Present Value Analysis																				
Present Value to Jan 1, 2014	**$27,723,060**	**$3,032,050**	**$2,944,031**	**$2,858,900**	**$2,776,557**	**$2,696,905**	**$2,619,851**	**$2,545,305**	**$2,473,179**	**$2,403,391**	**$2,335,859**	**$2,270,507**	**$2,207,258**	**$2,146,040**	**$2,086,785**	**$2,029,423**	**$1,973,891**	**$1,920,126**	**$1,868,067**	**$1,817,656**
Running Total	**27,723,060**	**30,755,110**	**33,699,141**	**36,558,041**	**39,334,598**	**42,031,504**	**44,651,355**	**47,196,660**	**49,669,839**	**52,073,230**	**54,409,089**	**56,679,596**	**58,886,854**	**61,032,894**	**63,119,679**	**65,149,102**	**67,122,994**	**69,043,119**	**70,911,186**	**72,728,842**
Total 10-Year Present Value	**$52,073,230**																			
Total 15-Year Present Value	**$63,119,679**																			
Total 20-Year Present Value	**$72,728,842**																			
Total 30-Year Present Value	**$88,457,641**																			
Comparison with Base Case - NG Package Boiler																				
Capital cost difference	**$21,600,000**																			
Operating Savings/(Costs)	**1,557,963**	**1,477,719**	**1,400,804**	**1,327,089**	**1,256,448**	**1,188,761**	**1,123,913**	**1,061,791**	**1,002,290**	**945,305**	**890,739**	**838,495**	**788,483**	**740,614**	**694,803**	**650,970**	**609,035**	**568,923**	**530,563**	**493,884**
Running Total	**1,557,963**	**3,035,682**	**4,436,486**	**5,763,576**	**7,020,024**	**8,208,785**	**9,332,698**	**10,394,489**	**11,396,779**	**12,342,084**	**13,232,823**	**14,071,318**	**14,859,801**	**15,600,415**	**16,295,218**	**16,946,188**	**17,555,222**	**18,124,146**	**18,654,708**	**19,148,592**
Time Value Payback, years	**26.6**																			
Payback Calculation																				

Notes
1. Includes cost for remaining thermal needs of the plant and correction for boiler efficiency difference between the two alternatives.


Graph 1 - Economic Analysis Results
$100,000,000
$90,000,000
$80,000,000
$70,000,000
$60,000,000
$50,000,000
$40,000,000
$30,000,000
$20,000,000
$10,000,000
$0
Present Value Running Total
0
5
10
15
20
25
30
35
Years
Natural Gas Package Boiler
Digester
Hurst Boiler
EPI BFB Gasifier

Appendix I

Natural Gas Usage

Project 22870.01 - Biomass Boiler Study
Heartland Renewable Energy
Natural Gas Usage
December 22, 2010

Base Case: Natural Gas Package Boiler		
Package boiler steam production	67000	lb/hr
Total Natural gas heat input	85934442	BTU/hr
	85.93	**mmBTU/hr**
Alternative 1: Digester		
Package boiler steam production	67000	lb/hr
Total required heat input	85934442	BTU/hr
Digester gas heat input	37895000	BTU/hr
Total Natural gas heat input	48039442	BTU/hr
	48.04	**mmBTU/hr**
Alternative 2: Hurst		
Biomass boiler steam production	46732	lb/hr
Package boiler steam production	20268	lb/hr
Natural gas heat input into package boiler	25995448	BTU/hr
Total heat required for spray drying	19820455	BTU/hr
Amount provided by biomass bomass boiler exhaust	9826790	BTU/hr
Natural gas heat input into the spray dryer	9993664	BTU/hr
Total Natural gas heat input	35989113	BTU/hr
	35.99	**mmBTU/hr**
Alternative 3: EPI		
Biomass boiler steam production	48067	lb/hr
Package boiler steam production	18933	lb/hr
Natural gas heat input into package boiler	24282906	BTU/hr
Total heat required for spray drying	19820455	BTU/hr
Amount provided by biomass bomass boiler exhaust	9577433	BTU/hr
Natural gas heat input into the spray dryer	10243022	BTU/hr
Total Natural gas heat input	34525927	BTU/hr
	34.53	**mmBTU/hr**

Note:
Includes cost for remaining thermal needs of the plant and correction for boiler efficiency difference between the two biomass boiler alternatives.

Appendix J

Vendor Proposals

Monday, September 13, 2010

BASIC SOLID FUEL SYSTEM
BUDGETARY PRICING FORM

Contact Information:

Contact: Doug Einck
Company: Stanley Engineering Group
Address: 225 Iowa Ave.
City/State: Muscatine, Iowa
Zip Code: 52761

Phone: (563) 264-6554
Email: EinckDouglas@stanleygroup.com
Location: Midwest US
Salesman: GWS
Proposal #: (1)1800/250/091310

System Specifications:

Boiler Horsepower:	(1)1800	BTU Input:	75.3 MMBTUH
Boiler Vessel Type:	WT Series	Fuel Type:	Sugar Beets (dried Stillage)
Steam Output:	60,000 Lb/hr	Moisture Content:	5.5% approx.
BTU Output:	60.2 MMBTUH	BTU Content:	8,110/lb.
Design PSI:	250	Stoker Type:	Reciprocating Grate
Max Operating PSI:	225		

System Pricing:

Fuel Metering Bins	Included
HBC Boiler Fireman Control System w/ O2 Trim, Computer, Remote Annunciation	Included
Fuel Feed Floor	Included
Inclined Conveyor from Fuel Floor to Metering Bins	Included
Reciprocating Grate Stoker	Included
Hurst "HD" Type Wet ash chain	Included
Water Tube Boiler Design	Included
Optional Soot blower system with Auto valves	Included
Optional Combustion Air Preheater (for fuels >35% M.C.)	Not Included
Economiser unit	Included
Optional 70,000 Lb/hr Deaerator unit	Not Included
Secondary Emissions Control	Not Included
SNCR Injection system with pump skid	Not Included
Furnace Refractory	Included
Start-up of Equipment	Included
Fuel storage	Not Included
NOTE: This is a budgetary proposal only based upon information supplied by SG	
Sub Total	$4,650,000
Erection Labor Only - No Cranes/Lifts, etc.	885,390.00
Budget Price	$5,535,390

Note: All pricing is in USD, FOB Coolidge, GA, USA and does not include shipping, lifts, taxes, fees/bonds, tariffs, duties, etc. This budgetary proposal is valid for 30 days from date of document. Standard terms are 35% upon order, 55% upon notification of preparedness to ship and 10% upon completion or delivery, as the case may be. Current delivery schedules are 10 to 12 months from order receipt to shipment
Thanks for the opportunity to provide these budget numbers for your analysis.

Note: Installation and final component pricing will depend upon site conditions and layout.

Greg W. Smith

Global Energy Solutions, Inc. – Agent for Hurst Boiler and Welding Company
100 West Roosevelt Road
Wheaton, IL 60187
Phone: (630) 668-8900, e-mail: GESChicago@SBCGlobal.net

Einck, Douglas

From: Jim Starkey [jastarkey@energyproducts.com]
Sent: Monday, August 02, 2010 3:17 PM
To: Einck, Douglas
Cc: Kent Pope; Paul Logan; Teresa Heller
Subject: Budget Proposal - Confidential and Proprietary

Energy Products of Idaho

The Biomass-to-Energy Company

4006 Industrial Avenue, Coeur d'Alene, Idaho 83815
Ph. 208/765-1611, Fax 208/765-0503

August 2, 2010

Mr. Doug Einck
Senior Mechanical Engineer
Stanley Consultants, Inc.
225 Iowa Avenue
Muscatine, IA 52761

EPI Ref: Project #10076
Subject: Budget Proposal - Confidential and Proprietary

Dear Doug :

Thank you for your interest in Energy Products of Idaho (EPI) and our fluidized bed energy systems. EPI is pleased to submit this order of magnitude budget proposal for your consideration.

EPI's technology is the solution for a wide variety of renewable energy applications or where waste material having energy value is a disposal problem. About 100 EPI fluidized bed combustion/gasification systems are located throughout the world in the industries of wood products, paper, power generation, agriculture, food processing, and municipalities recovering energy in wastes such as municipal garbage and sludge, paper, paper sludge, plastic, manure, biomass, coal, wood, and numerous other materials. EPI's fluidized bed is especially suitable for applications requiring fuel flexibility or handling multiple fuels in a single system while generating the lowest possible emissions.

EPI's innovation and experience have made us the world leader in fluidized bed combustion/gasification system technology. Our patented bed cleaning system allows continuous automatic cleaning of the bed material while the system continues to produce energy for the process. This proven feature allows energy recovery from waste materials having a significant percentage of noncombustible contaminants, such as rock and metal, with no down time associated with regular cleaning.

In addition, for fuels that have not been tested, EPI has a pilot test facility at our headquarters in Coeur d'Alene, Idaho for demonstration, permitting, and design development purposes.

In response to your specific inquiry, EPI offers the following rough order of magnitude budget proposal for a boiler utilizing dried ethanol stillage as the primary fuel and producing 60,000 #/hr of saturated steam at 200 psig:

- ❑ EPI fluidized bed advanced staged gasifier complete with EPI's proprietary/patented automatic bed media cleaning and reinjection system
- ❑ Start-up burners
- ❑ In-bed tubes

- ❏ Custom biomass boiler
- ❏ Metering bins and fuel feed
- ❏ Bed media storage system
- ❏ Economizer
- ❏ SNCR for NOx control
- ❏ Limestone injection for SO2 control
- ❏ Dry scrubber
- ❏ Baghouse for particulate collection
- ❏ Ash system with storage tank and conditioner
- ❏ 100' Stack
- ❏ CEMS/Extractive
- ❏ FD and ID fans
- ❏ Interconnecting ducts (refractory lined and unlined)
- ❏ Local panels
- ❏ PLC control system with an HMI interface for integration into a plant control system (by others)
- ❏ Access stairs, decks and ladders
- ❏ 3 man months of EPI Erection advisors services
- ❏ 3 man months of EPI Start up advisors and operator training services

EPI can accept dried ethanol stillage fuel sized to less than four inches in any direction, with 90 percent less than three inches in any direction and not more than 10% smaller than ¼-inch, which saves in fuel processing costs.

The budget price for the energy system described above is US$ 7.5 million, FOB point of manufacture.

Some of the items not included in the above price are:

- fuel processing, handling, or storage systems
- erection advisors services beyond that included above (available at EPI's standard per diem rates)
- start up advisors and operator training services beyond that included above (available at EPI's standard per diem rates)
- installation
- foundations and civil work
- balance of plant (BOP)
- plant distributed control system (DCS)
- buildings and landscaping
- fire suppression systems
- freight
- taxes
- permits (building or environmental)
- external insulation and finish paint
- other items typically supplied by the installation contractor

While the above is not an exhaustive list of the equipment which is or is not supplied, it provides you with a basic idea of the scope of supply EPI normally provides.

EPI typically estimates complete mechanical and electrical installation costs to be approximately 55-60% of the capital cost quoted for EPI's scope of supply. This does not include foundations which are to be provided by others. The installation estimate is based upon a typical installation in the US using non union labor.

We look forward to working with you on your dried ethanol stillage project. After reviewing this proposal please feel free to call me if you need additional information or have any questions. Thank you again for your interest in Energy Products of Idaho.

Sincerely,

ENERGY PRODUCTS OF IDAHO

Jim Starkey
Business Development Manager

cc: Kent Pope, Teresa Heller, Paul Logan - Energy Products of Idaho

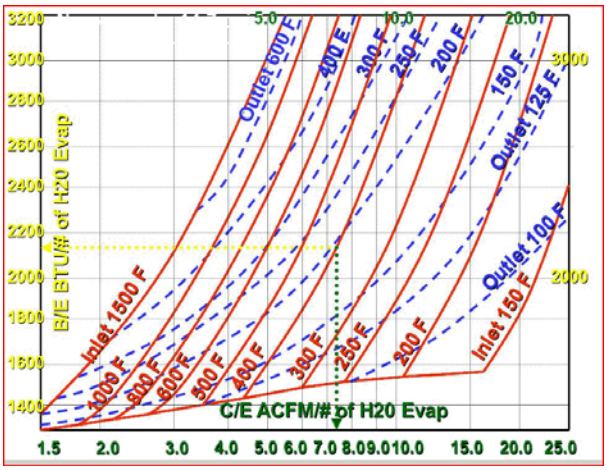
Jim Starkey
Business Development Manager
Energy Products of Idaho
3568 W Industrial Loop
Coeur d'Alene, ID 83815
Phone: (208) 765-1611
Fax: (208) 765-0503
Email: jastarkey@energyproducts.com
Website: www.energyproducts.com

Einck, Douglas

From: James Schak [james.schak@geagroup.com]
Sent: Friday, October 01, 2010 7:59 AM
To: Einck, Douglas
Cc: ajohnson@ssitechnology.com; Matthew Walter; Matthias Loewenberg
Subject: Sugar Beet Spray Dryer

Inquiry: 20.14104 (Stanley Consultants Inc - Muscatine, IA USA)
Doug,
This is to confirm our discussions earlier in the week. We understand that you have a liquid sugar beet stream at 155 gpm at 20% solids. You expect to be able to increase the solids concentration to 55% in an evaporator.(I have attached your contact information for our evaporator group to contact you).

We estimate the solids rate to the spray dryer to be about 15,512 pph
(155 gal/min x 8.34 #/gal x 60 x 20% = 15,512 pph) :
The feed rate should be about 15,512/.55 = 28, 204 pph
Feed Rate: 28,204 pph
Feed Solids: 55%
Evaporation Rate: 11875 pph
Product Moisture: 5%
Product rate: 15,512/.95 = 16.328 pph
Inlet air temperature: 500 F(guess)
Outlet air temperature: 200 F(per Doug)
Expected air flow required per attached chart: 5 cfm/# water evaporated

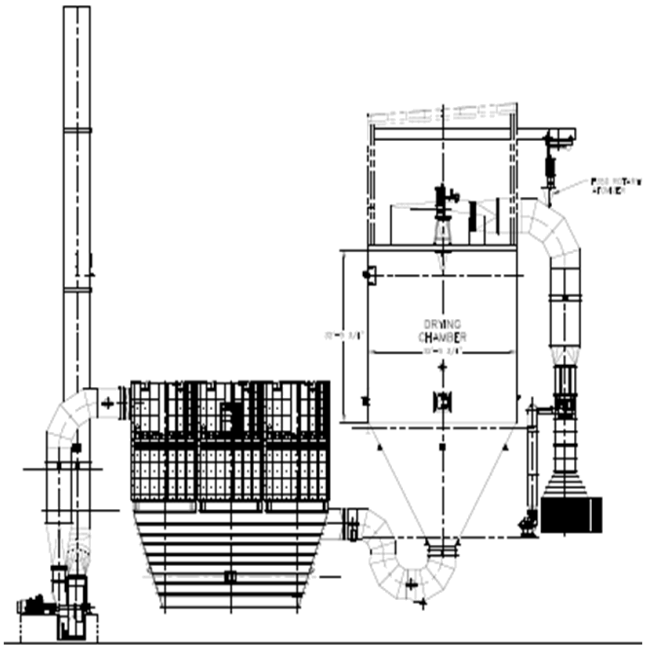


Need about 60,000 acfm or about 93,500 kg/hr or an SD-1000
Btu Requirement is about 2000 btu/# of water evaporated or 23.75 million
Order of magnitude Price: $3,000,000 for the following:
Gas Air Heater
32 ft diameter spray drying chamber
Baghouse
exhaust fan
controls

interconnecting ductwork

Building, insulation and installation by others

Typical arrangement drawing:



Let me know if you need more information.
jim

Best regards

James Schak
National Sales Manager - Chem Systems

GEA Process Engineering Inc.
Powder Processing Division
Office: 1-973-316-2499), Mobile: 973-879-3808
james.schak@geagroup.com
www.niroinc.com

GEA Process Engineering Inc.

Jim,
Any chance you can call this guy Doug Einck at (563) 264-6554. He is with Stanley Consultants.

He is looking to come up with some feasibility numbers for a spray dryer, he wanted me to give him numbers over the phone.

Basically, has a sugar beet process that they are making ethanol, and the leftover stillage is 20% solids.
They want to run through a multiple effect evaporator at 155GPM and are looking for 55% solids to feed into a spray dryer and end with 90% solids.
End game is they are going to burn the product as fuel.

Caveat is he has a boiler that he wants to use exhaust gas, 70,000 llbs an hour at 680F.

My guess is he is going to find it is not a feasible project, but obviously would like to get him the information he wants.

Andy Johnson
SSI Technology, Inc
ajohnson@ssitechnology.com
Phone: 319-294-9637
www.ssitechnology.com

Einck, Douglas

From: Craig Leonescu [craig.leonescu@geagroup.com]
Sent: Monday, October 04, 2010 10:21 AM
To: Einck, Douglas
Cc: Matthias Loewenberg
Subject: Budget Price-Evaporator

Hello Doug,

Per our conversation this morning, I would offer a 4 effect Falling Film Evaporator including the following:

A. 4 Ea. Falling Film Evaporator Chests
B. 4 Ea. Vapor Separators
C. 5 Ea. Preheaters (1 plate + 4 Tubular)
D. 1 Ea. Surface Condenser
E. 1 Lot of Vapor Ducting
F. 1 Lot of Process Pumps
G. 1 Lot of Vacuum Pumps
H. 1 Lot of Field Instrments and Automatic Valving
I. 2 Ea. Condensate Collectors
J. 1 Ea. Feed Balance Tank.
K. 1 Lot of Engineering to include P&ID, Arrangment and Foundation Drawings, Tag List, Functional Description and Equipment Outline Drawings, reccomended piping drawings.

Process Information

Feed Temp (Assumed)=75 F
Feed Flow=89,000 PPH, 20%TS
Evaporation=56,668 PPH
Discharge Flow=32,332, 55% TS

Steam Required (15#) =17,426 PPH (this can be lower if feed temperature comes in higher)

Cooling Water =2,400 GPM 85 F to 100 F

Electrical Requirements (10 Process Pumps + 2 Vacuum Pumps)=135 HP (Installed)

Budget Price= US$1,950,000 +/- 15%

Delivery=+/- 26 Weeks

Please let me know if you need anything else.

Best regards,

Craig Leonescu
Senior Process/Sales Engineer

GEA Process Engineering Inc.
Evaporation & Crystallization Technologies Department
Office: 410-997-6611, Mobile: 443-831-2258, Fax: +1410-997-5021
craig.leonescu@geagroup.com
www.niroinc.com

GEA Process Engineering Inc.
9165 Rumsey Road, Columbia, Maryland, 21045, USA

Appendix K

Test Burn Results

Global Energy Solutions, Inc.

November 24, 2010

Mr. Doug Einck
Stanley Group Consultants
225 Iowa Avenue
Muscatine, Iowa 52761

PH: (653) 264-6554
e-mail: EinckDouglas@stanleygroup.com

Doug:

Global Energy Solutions, Inc. is please to provide your requested report for the combustion analysis that has been performed on the fuel sample which you provided to us from your Midwest US sugar mill facility that will be/is located in North Dakota.

Your two (2) samples have been received and processed as follows: one sample was received at our office in Naperville and has been delivered to Hurst Boiler in Coolidge, Georgia for analysis by their engineering team. The second sample was sent directly to the independent laboratory that we and Hurst Boilers use for analysis. Due to the lack of any history or baseline with this potential fuel feedstock, a simple standard burn test would not adequately determine if any anticipated combustion problems would be encountered by our biomass-fired boiler systems. Therefore, we had the Hurst engineering team analyze one sample of the material at the factory, and our independent laboratory has conducted the following combustion tests on the fuel sample, simultaneously:

1. Proximate Analysis Test
2. Ultimate Analysis Test
3. Ash Fusibility Test
4. Chlorine Test

The Proximate Analysis gives us moisture content, volatile content, free carbon and ash content values. The Ultimate Analysis has gives us the composition of the biomass in percentage weight of carbon, hydrogen, oxygen, sulfur and nitrogen (if any). The Ash Fusibility Test involves classifying the slagging potential of the ash and its possible effect on boiler performance. The Chlorine Test identifies any possible formation of potentially harmful chlorine-based acids in the boiler flue gas stream.

The combustion test results that we received from our independent laboratory is very similar and therefore mirrors the results from the Hazen Research, Inc. test results dated 7/14/2010 for this same sample that you sent to us a couple of weeks ago. In addition to the above

testing, we have been able to analyze your fuel sample to determine its desirability for the proposed biomass-fired system. We have also listed the resulting quantity of ash that would be produced and which would have to be either sold or otherwise disposed of. This value is important because it varies widely with different fuels. As a comparative example typical Douglas fir burn tests usually produce ash percentages as low as 0.75%, while wheat straw produces over 8.0% ash. The spray dried Clarified wine sample that we had analyzed revealed the fuel-bound ash component to be nearly 30%.

Based upon the lab results shown above, and the analysis by the Hurst engineering team, we/Hurst have been able to determine the that our recommended grate system is either the Hurst Boiler Company flaking grate system, or to utilize another manufacturers grate system in conjunction with the Hurst Boiler system in order to be able to provide both the handling of the very high percentages of the reported fuel-bound ash, as well as to be able to obtain as complete a combustion process as possible. Due to the very low moisture content of the clarified wine sample combined with the high ash content and the very small particle size of the fuel, we have three options for your consideration to combust this material. All three furnace/combustor system options that we propose to you and your client will all utilize the Hurst boiler configuration and are detailed as follows:

Base System – Hurst Standard Flaking Grate with Water Tube Boiler Design with Mixed Fuel

- Utilize the flaking grate furnace section without cyclonic solid fuel burner or natural gas partial supplemental firing system. This standard flaking grate solid fuel system would be best utilized firing a mixture of the clarified wine fuel as tested and another wetter biomass material such as woody biomass or other similar fuel source. The least problematic fuel mixture would be 50/50 each fuel, with a recommended minimum woody biomass component of at least 25% of the total fuel mixture. This system signifies the baseline system configuration and **Base Price**. We have already located the required mixed biomass fuel for the area that we believe the plant will be located in from multiple sources. This mixture of fuels would mitigate potential intermittent incomplete combustion issues of the lower moisture content and higher ash content of the clarified wine fuel sample as tested.

Alternate #1 – Hurst Standard Flaking Grate with Cyclonic Burner to Burn All Tested Solid Fuel

- Utilize the flaking grate furnace section with two (2) cyclonic solid fuel burners with natural gas starter and part-time supplemental fuel source to even out full combustion. This system will have no problem using 100% clarified wine fuel as tested. Please see attachments for example of cyclonic solid fuel burners that are

proposing to utilize with the standard Hurst Flaking Grate combustion/boiler system. This alternate #1 Hurst Flaking Grate boiler/combustor system would have an approximate price = the Base Price (above) plus $650,000.00 for the addition of the two (2) cyclonic solid fuel burners. The use of the cyclonic solid fuel burners and a minor and intermittent amount of supplemental/start-up natural gas would mitigate the combustion issues of the tested fuel as the main fuel source.

Alternate #2 – Fluidized Bed Combustor with Hurst Boiler and Start-Up Burners

- Utilize a fluidized bed burner provided by a manufacturing partner that is matched to the Hurst water tube boiler and control system with in-bed natural gas start-up burners required to maintain constant bed temperature as is the standard with fluidized bed combustion. The use of the fluidized bed combustor, like Alternate #1 above, will allow for near 100% tested fuel use as the main combustion fuel. The fluidized bed combustor will be slightly modified from standard to accommodate the 30% (approximate) fuel-bound ash in the tested fuel. See attached schematic detailing the fluid bed combustor. This alternate #2 Hurst water tube boiler/fluid bed combustor system would have an approximate price = the Base Price plus $1,400,000.00+ (plus, greater than $ 1.4 million USD) for this system with natural gas start-up burners over and above the Base Price system, above. The use of the fluid bed combustor and a minor and intermittent amount of supplemental/start-up natural gas would mitigate the combustion issues of the tested fuel as the main fuel source.

In all three (3) options listed above, the control system and combustor/boiler system guarantee would be by Hurst. The test results have gives us good direction on the type of secondary emissions control components and system that we use/recommend for this particular application. The initial feedback from the various secondary pollution control system manufacturers that we have worked with for this project have all stated that their standard secondary pollution control systems would be slightly modified for this fuel, however, the pricing and the components would remain the same for each of the three (3) alternates proposed above.

As we have discussed previously, a few requirements for all our options listed above that we do have are the physical fuel particle size, which is recommended to be 2-1/2” minus, which restricts the length in any of the sides (L by W by H), and the overall moisture content of the fuel (or fuel mix) which cannot exceed 55%, and the percentage of fuel bound ash should not exceed around 35 to 40%.

Thank you for the opportunity to be of service to you on this project. We look forward to working with the Stanley Group on this project, and we await your direction on how to proceed with the above listed and proposed options.

Please feel free to call me at our new office number listed below, or on my cell # (630) 962-6869 with any questions regarding our report.

Best regards,

Greg W. Smith

Gregory W. Smith, BSIC, MEM
Global Energy Solutions, Inc.

See attachments