CLEAN ENERGY TECHNOLOGIES

Re-Capitalization of Yukon College Gasifier

By

CANMET Energy Technology Centre – Ottawa
Industrial Innovation Group

For

Yukon Mines Energy and Resources

May 2009

Natural Resources Canada   Ressources naturelles Canada

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DISCLAIMER

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1 Executive Summary

A study was commissioned by Yukon Energy Mines and Resources to address the detailed economics for the re-capitalization of a fluidized bed gasifier installed for space heating at Yukon College, Whitehorse. This study was to be based on changes recommended by a CANMET Energy Technology Centre – Ottawa (CETC-O) study carried out in 2004, with emphasis on reactor re-design, process control and emissions control.

Recommendations

Re-capitalization of the Yukon College Gasifier is recommended at a cost of $425k for fluidized bed, boiler and control system modifications.

A pellet storage and feed system is recommended for trouble-free operation although the present feed system should be retained for research into alternate local fuels. The pellet storage system cost was estimated at $47k. The addition of a pellet storage system would allow the gasifier to be co-fired (i.e. fired simultaneously) with pellets and an alternate fuel, e.g. wood chips, cardboard wastes.

Given that a scrubber offers the potential increased heat recovery from the scrubber water and therefore higher efficiency it is recommended that the gasifier re-capitalization project include a scrubber ($101k) as the emissions control technology. Emissions levels below 35 mg/Nm^3 should be achievable by a properly designed system.

Implementing these recommendations (plus $100k engineering fees) brings the total re-capitalization cost to $765k. Based on relatively high cost of pellets of $300/tonne and one additional operator this represents a simple payback of 9.6 years when compared with off-peak electricity. If the comparison is with fuel oil at $1.50 per litre the payback period drops to 1.6 years

In the event that the Yukon Government chooses to replace the existing facility with a new biomass-fired system, CETC-O recommends a modular pellet furnace based system which could be installed at a cost of $786k. This figure does not include emissions control (minimum $100k), removal of existing equipment, building modifications or engineering fees.

The Yukon College gasifier would be an ideal research facility which would allow the Yukon Government to establish a Canada-leading Centre of Excellence on pellet utilization, renewable combined heat and power for northern communities, liquid bio-fuels and hydrogen economy developments. As a first stage in this initiative, a combined heat and power system based on the re-capitalized gasifier could be established for approximately $365k.

Report Summary

Based on changes recommended by a CANMET Energy Technology Centre – Ottawa (CETC-O) study carried out in 2004, the reactor redesign presented in this report is focused on the lower section of the bed, where the air enters the system and ash and bed material is removed. Other system modifications include: increasing the fuel storage, adding an emergency exhaust system, increasing insulation along the syngas path to the B1 boiler, reconstructing the syngas diffusers at the B1 burner head and sealing the end of B1 boiler to prevent release of syngas into the boiler room.

The cost of all fluidized bed and boiler system modifications are estimated as $205,136. A new control and monitoring system including capability for on-line syngas analyses and which will allow operation of the unit in both gasification and combustion modes was estimated at $220,045. The cost of the reactor and control system modifications is thus $425,181. The cost summary is shown in Table 1.

Table 1 List of Estimated Costs for FB System Re-design & Controls

Fluid Bed System Re-design	
Elevation and Support	$ 48,535
Pre-Heat Burner	$ 5,148
Air Distributor	$ 38,652
Ash Cooling and Removal	$ 19,190
Emergency Exhaust	$ 21,590
Syngas Transport	$ 21,391
Boiler B1 Mods	$ 24,230
Refurbishment Labour	$ 26,400
Section Total	**$ 205,136**
Controls & Data Acquisition	
Instrumentation	$ 17,590
Gas Analysis/Monitoring	$ 36,500
Cabling	$ 2,900
Control System/ PLC	$ 7,505
Burner Management Systems	$ 11,000
Control Panels	$ 11,500
Miscellaneous	$ 17,400
Labour	$ 115,650
Section Total	**$ 220,045**

There are a number of options which can be implemented in order to control emissions, namely particulate emissions. Other emissions, such as, NO_X and SO_2 are minimized by the fuel specifications and will not require additional control. An oxygen sensor has been included in the control for B1 boiler and this will allow proper control of excess levels in the boiler, which will ensure that carbon monoxide levels are minimized. Control of particulate emissions will however require a secondary or external device. A number of options were considered:

- A Venturi scrubber at a cost of $100,650 with emissions below 35 mg/Nm^3
- An Electrostatic Precipitator (ESP) at a cost of $362,000 with emissions of 30-35 mg/Nm^3
- A Wet ESP at a cost of $474,600 with emissions of 15 mg/Nm^3

Owing to the small size for this type of device, the ESP and Wet ESP is based on design criteria and not proven technology. In any event, ESP performance is not superior to a Venturi scrubber and therefore the choice is between the scrubber and the Wet ESP. Given that the scrubber offers potential increased heat recovery from the scrubber water and therefore higher efficiency, it is recommended that the gasifier re-capitalization project include the Venturi scrubber as the emissions control technology. Note: Another approach to reducing emissions would be to also scrub the syngas prior to combustion in the boiler. The combustion in the boiler would then be of essentially clean gas and should easily meet the 15 mg/Nm^3. The scrubber between the gasifier and the boiler would also necessitate an additional heat exchanger and generate a liquid stream containing tars which would require additional treatment. One benefit of carrying out this additional syngas clean-up would be that the syngas would already be substantially cleaner for potential future installation of a reciprocating engine for power generation.

A number of options have been studied for additional and alternate fuel feed systems. The existing bunker system is marginally adequate in terms of capacity with one days' storage, however the system is prone to operational problems. Unless the wood chip quality (especially size) is carefully monitored, the system is prone to jamming and the design makes clean-out very time-consuming. This could be remedied to a certain extent by demanding fuel meet certain specifications. For wood chips this would be:

- Maximum dimension of 2"
- Less than 5 % fines (particles < .5 mm)
- Moisture Content: 10 to 20%
- Ash (and dirt): 0-1.5%
- Heating Values: >18.5 MJ/kg on a dry basis

The capacity could be extended by using pellets and filling on average once every 3-4 days, however a better solution would be to install a higher capacity and more "automated" feed system. In terms of ease of operation the recommended approach would be to use wood pellets and install a pellet silo (in essence a modified grain silo). Such a system could be installed for $46,616 and would provide 55 tonnes of on-site storage, enough for 4 days of operation at maximum capacity. This approach would require the least operator involvement and assure smooth gasifier operation and allow evaluation of alternate fuels including simultaneous firing of fuels from the existing wood chip system and the pellet silo. The drawback to pellet use is that pellets are not currently produced in the Yukon and therefore the pellet fuel would be expensive, estimated at $300 per tonne against cost of wood chips of approximately $150 per tonne. Note that these fuel prices are double what is commonly available in "Southern Canada".

CETC-O has carried out designs for three wood chips options:

- a small covered 50 tonne bin with a walking floor
- a large 200 tonne bin with a walking floor and automated levelling system
- a dual fuel auger system which would need to be in an enclosure

All of these options would require installation of a concrete pad and although potential locations exist near the boiler house, the exact selection of site requires input from the Yukon Department of Highways & Public Works. The cost of these options are $278,647 for the small bin; $718,647 for the large bin and $483,004 for the dual fuel auger system. The dual fuel system is high as the price already includes $284,000 for an enclosure. One additional note is that the small covered bin would require that the fuel supplier invest in a walking floor truck which requires an investment of approximately $100k.

The option recommended by CETC-O is the installation of the pellet silo at a cost of $46,290. This option includes refurbishment of the existing bunker (including additional screens) for use with alternate fuels. Note that installation of the pellet system would not preclude installation of one of the other wood chip options at a later date. It would however considerably facilitate the re-capitalization process; require less operator involvement and more significantly, this would be the start of establishing a market for pellets in Whitehorse thus opening up the potential for a local pellet production plant to be established.

The overall cost based on the above recommendations thus comes to $664,447. The supervision of installation and commissioning by CETC-O staff has been estimated at $100,000 which brings **the total cost of recapitalization to $764,447 plus any applicable taxes.** The detailed cost items are shown in Table 2. This does not include taxes (i.e. GST) and also does not include the suggested addition of a second scrubber (~$120k) for the syngas to ensure minimal emissions and also as a prelude to potential power generation from the gasifier.

Table 2 Complete List of Estimated Costs

Fluid Bed System Re-design	
Elevation and Support	$ 48,535
Pre-Heat Burner	$ 5,148
Air Distributor	$ 38,652
Ash Cooling and Removal	$ 19,190
Emergency Exhaust	$ 21,590
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Burner Management Systems	$ 11,000
Control Panels	$ 11,500
Miscellaneous	$ 17,400
Labour	$ 115,650
Section Total	**$ 220,045**
Emissions Control	
Ventrui Scrubber	$ 100,650
Flue Gas Path/Fan Mods	$ 92,000
Section Total	**$ 192,650**
Fuel System	
Pellet Storage	$ 66,616
Section Total	**$ 66,616**
CETC-O Project Mgt	**$ 100,000**
TOTAL	**$ 764, 447**

In order to carry out a financial analysis, the following have been assumed for "year zero" prices:

Pellets:	$300/ODT
Wood Chips:	$150/ODT
Fuel Oil:	$1/litre
Electricity:	80% of cost of Fuel Oil (8.88 ¢ per kWh based on oil @$1)

Pellets and Wood Chips increase at inflation rate of 2% per annum, fuel oil is projected to increase at 5% per annum and electricity increases are averaged between inflation and

80% of the rise in fuel oil. Table 3 presents the estimated cumulative costs of heating with the various fuel options:

Table 3. Cumulative 25 Year Heating Costs

Pellets:	$17.6 M
Wood Chips:	$10.5 M
Fuel Oil:	$32.0 M
Electricity:	$21.5 M

In this analysis, electricity starts as the least expensive and is overtaken in year 4 by wood chips which then remains the least expensive option. Electricity remains less expensive than pellets until year 10 at which point pellets become favoured. Fuel oil is only less expensive than the biomass options until years 2-3. After year 4, fuel oil is always the most expensive option.

Based on this analysis the best strategy would appear to be to carry out the re-capitalization of the gasifier but maintain the electricity capability to take advantage of potentially “cheap” power. The gasifier should be equipped with the capability to fire pellets which is the least technically challenging option but the gasifier’s exisiting wood chip system should be integrated into the controls so that the gasifier could also operate on wood chips which are the potentially lowest cost fuel. Fuel oil heating is by far the most expensive option and is not recommended.

As detailed in the report, the gasifier would be an ideal research facility on pellet utilization, renewable combined heat and power for northern communities, liquid bio-fuels and hydrogen economy developments. As a first stage in this initiative, the principal components for a combined heat and power installation based on the gasifier would be for syngas clean-up, an engine/generator set and electrical connection panel. The first stage of syngas clean-up would consist of a scrubber and heat exchanger. The second component would be a filter/de-mister which would have to be custom-built. At this point the syngas should be clean enough for a relatively robust engine such as a Kohler 500 kWe engine. A preliminary estimate of installing a combined heat and power system to the re-capitalized gasifier set-up would be $365,000 plus taxes.

Alternate Heating Options

At the initial completion of this study, CETC-O was asked to consider replacing the gasifier with entirely new biomass-based heating system. The following are two options and expected costs: one is for a wood chip system, the other a pellet-based system. CETC-O selected suitable systems from commercially available systems – this is not based on an exhaustive evaluation or comparison of available systems. CETC-O does not endorse either system presented included in this report, they are presented simply as suitable potential alternates.

Alternate Option 1: Wood Chip-Based Heating System

A 4.5 MWth Vyncke water-cooled step grate furnace has been quoted to provide a comparision to the refurbished fluidized bed system. The Belgium-built Vyncke can be supplied in Canada by Thermo Energy Systems of Leamington, Ontario. The quote includes the fuel feed system, 4.5MWth combustor, automatic wet-ash removal, dust collector, ESP, hot water storage tank and a chimney stack. The pricing is shown below with a grand total of $1,975,987. Please note the list of components that are not included in the quote. The layout of the feed system and combustor has a total area requirement of 9,450 ft^2 which exceed the requirements of the current boiler room. A new addition to the exisiting building would therefore be required. This cost has not been included here.

Wood Chip Grate Furnace System Cost Estimates

Equipment	Cost
4.5 MWth grate furnace	$ 891,675
Thermo Energy Systems	$ 505,000
Silo unloading system with moving floor	
Chain conveyor for fuel transport	
Chain conveyor for wet ash evacuation	
Dust Collector	
Automatic fly ash evacuation system	
Flue gas ducting without insulation	
Chimney	
Hot Water Storage Tank (757,082 L)	$ 282,312
Electrostatic Precipitator	$ 297,000
Total	**$1,975,987**

Excluded in this price: concrete and foundation work; rotary air lock valves for fly ash; all electrical wiring (low and high voltage); all permitting for project; transportation of equipment; hydraulic fluids, fittings, and pipe; all applicable taxes; ash bin; crane and other equipment rentals for unloading and erecting; emission control equipment.

Alternate Option 2: Pellet-Based Heating System

CETC-O staff carried out a review of available technologies and decided that a modular approach would be best suited for the Yukon College in order to take advantage of the existing space and allow for load changes and also some redundancy. It would be possible to install a wood chip boiler such as considered under Alternate Option 1 and burn pellets in the unit. However, given the substantial capital cost for wood chip handling equipment and the high cost of pellets this would be a very expensive mode of operation. CETC-O indentified a suitable system for burning pellets – KOB Pyrtec KPT-1250 with a rated heat output of 1250 kW. This is a German-made unit which could be supplied in Whitehorse by Fink Machine Inc, of Enderby BC. The installed cost of one KPT-1250 excluding pellet storage and feed system is estimated at $360,000. Pellet fuel storage costs would be as noted above for gasifier re-capitalization or approximately $66,000. In order to replace the gasifier a minimum of two KPT-1250 furnaces would be required thereby bringing the cost of the units to provide 2500 kW to $786,000. In terms of space requirements, the furnace footprint is 5.6 m x 2.2 m which translated into a 40 ft by 20 ft space to accommodate two units. These would fit within a “vacated” boiler house which has dimensions of 47 ft by 56 ft. The price for the KPT-1250 units does not include emissions control equipment.

The following is a summary of the various strategies:

		Equipment Cost incl. fuel feed
Re-capitalization of gasifier	(2500 kW)	$ 572k
New wood-chip furnace system	(4500 kW)	$1976k
New modular pellet furnaces	(2500 kW)	$ 786k

An emissions control systems would be required for all three of these systems and as noted above the cost of these would range from $100k to $500k depending on the type of system chosen.

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2 Introduction

In 1987 an air-blown fluidized bed gasifier was installed at Yukon College to provide space heating for the campus, located in Whitehorse, Yukon. The chosen design was based on pilot installations built for gasifying rice hulls, shredded tires, manure and refuse derived fuel. Upon construction of the Yukon College facility, attempts at commissioning failed and the original supplier withdrew from the project. A number of subsequent attempts were made by local consultants to troubleshoot and commission the unit; however, these efforts failed and the unit was taken out of service in 1991. Since then, a number of contracts and studies have been carried out to consider the economics of operating the unit, consider dismantling the unit or even consider re-furbishing the unit. Some of the studies have been contradictory and even made questionable assumptions but the end result is that the unit has been decommissioned and the boiler plant derated.

At the start of 2004, the gasifier and its boiler had been physically disconnected from the heating system at the college. The college had been running on an electric boiler using secondary electricity as its primary fuel source for over 2 years. However, this equipment is ageing and a decision will soon be required on replacement of some boiler equipment as well as whether the gasifier installation should be removed in order to accommodate the new equipment. At this point, the CANMET Energy Technology Centre (CETC-O) in Ottawa (part of Natural Resources Canada) was contracted by the Government of the Yukon, Department of Energy, Mines and Resources to carry out a technical and economic evaluation of the gasifier unit and recommend potential courses of action.

CANMET staff inspected the gasifier facility during the week of March 22 to 27, 2004. The status of the equipment, illustrated in Figure 1, is summarized as follows:

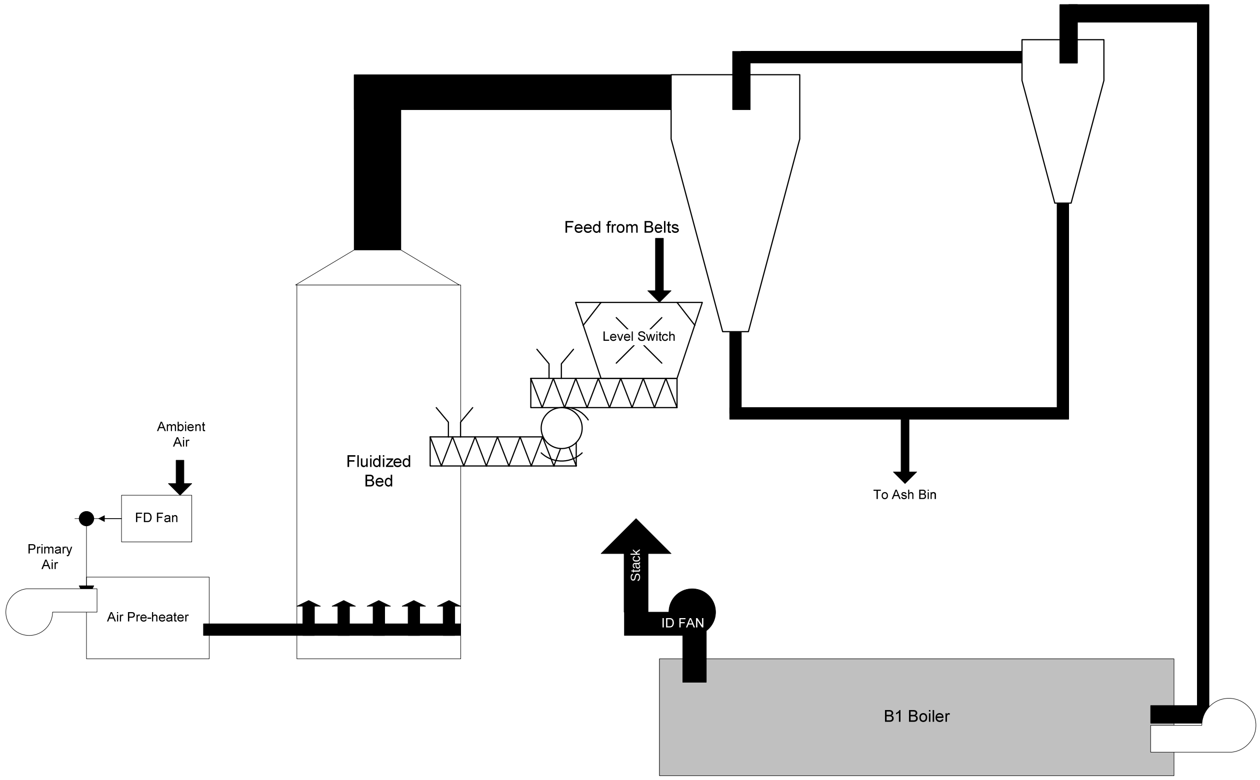

Figure 1 Existing fluidized bed system

The biomass feed system appeared to be in good working order. The feedrate is set by a manual dial (0 -5). In order to prepare for a test run of the gasifier, calibration tests were carried out for the feed system and a calibration curve was prepared. The recommended feedrate dial setting of 3.0 for gasifier operation corresponds to 400±20 kg/h (~ 2000 kWth; 7 MBTU/h)

The air delivery system was in good working order but lacked any capability to measure the flowrate of air or affect the portion of air diverted to the fuel feed system.

The gasifier is preheated by firing an oil "burner" into an air plenum where the air is heated to 650^{o}C. The pre-heater required some servicing but it was successfully fired as designed.

The fluidized bed gasifier, a 36" ID 170" high refractory lined (est. 8" thick) vessel, was found to be in good working order. Internal inspection of the gasifier found no damage to either refractory or air distribution pipes. The gasifier was found to contain sand which was determined to be suitable for further testing.

The syngas produced in the gasifier is combusted in a firetube boiler (B1) which can also be fired with No. 2 fuel oil. Syngas is supplied via a manifold to diffusers within the combustion chamber. The boiler is equipped with a Fuel Master Burner Model CO-300 firing No. 2 fuel oil @ 400 psi with a high fire rate of 80 USGPH (3664 kW; 12.5 million Btu/h). Examination of the combustion chamber found that the ceramic fibre blanket was in good condition. The syngas diffusers were found to have suffered severe corrosion. These would have to be replaced before any long term operation (with consideration given to better material of construction) however it was decided that the diffusers were adequate for the trial planned in this work.

Portions of the control system were found to be inoperative and had to be bypassed. After careful review including consideration of health and safety concerns, it was decided that the gasifier pilot plant could be run (in trial mode only) with a combination of additional temperature and pressure monitoring and manual control.

Once the various sub-systems had been tested, additional instrumentation installed (temperature and pressure sensors, manometers, data acquisition) and control strategy developed, a trial run of the gasifier was carried out on March 27, 2004.

The efficiency of boiler B1 was initially determined using only the No. 2 fuel oil burner. Under Lo-fire conditions (est. 20 USGPH) with 85% excess air, the thermal efficiency of the boiler was determined to be 85.8%. Under Hi-fire conditions (est. 80 USGPH) with 12% excess air, the thermal efficiency of the boiler was determined to be 86.5%. It should be noted that these tests were conducted over a relatively short period of time and so true steady state was not achieved, however the tests do indicate that as an oil-fired system, B1 boiler operates with good efficiency. The exact heat input for Lo and Hi-fire settings was not determined and documentation for these was unavailable.

The fluidized bed gasifier was successfully operated in combustion mode. Wood chips were fed at approximately 40 kg/h (0.75 dial setting) representing an input of 210kW (700,000 BTU/h). The fluidized bed temperature was easily maintained at approximately 750^{o}C and the unit operation was very stable. It is estimated that this unit without modifications could be used to produce at least 250 kW by operating in combustion mode. The size of the unit is such that up to 1000 kW could be produced by introducing a heat transfer surface in the fluidized bed region.

The fluidized bed gasifier was successfully operated as a gasifier for a brief period. Wood chips were fed at approximately 390 kg/h (3.0 dial setting) representing an input of 2050 kW (7 million BTU/h). The fluidized bed temperature was between 600 -700 C during the gasification period. Control of the air flowrate to the unit was done manually based on unit temperature response - this is a very poor control method especially since the actual flowrate is unknown and directions were generally of the type "turn the valve half a turn to the left". The trial was prematurely terminated due to two principal factors: a jammed fuel supply due to very large non-homogeneous chips and because the paint on *the outside of the burner section of B1 boiler began to smoke and burn. This in itself was a sign of successful production of large quantities of syngas.*

The findings of this evaluation are that the gasifier can be operated but not in its present condition. There are no significant health and safety issues with the operation of the gasifier. The major requirement is for new instrumentation for monitoring and control. The recommended changes are listed below under three categories: "Required" which have to be made for safe and controlled operation, "Strongly Suggested" for proper long-term operation and "Optimal" for optimal performance.

Required

- *Air Flow Measurement necessary for proper control of the gasifier.*

- *New Control System (hardware/sensors/software) as the existing control system is completely inadequate to properly operate the gasifier.*

- *Quality Control of Fuel to ensure a continuous stream of homogeneous dry chips.*

- *B1 Dilution Air Hood (Health and Safety Issue) to ensure that exhaust venting even under upset conditions is outdoors. (The potential is currently that exhaust could spill into the boiler room)*

- *Oil Lance (Pilot) and New Syngas Diffusers for B1 Boiler. A small oil lance/burner (1 USGPH) would be adequate to provide a source of ignition. In order to ensure proper mixing and burning of the syngas the existing diffusers which are badly corroded have to be replaced.*

- *Water Injection into the gasifier in order to prevent high temperature excursions which could cause premature shutdown of the gasifier.*

Strongly Suggested

- *A new pre-heat oil burner as the existing oil burner used to pre-heat the gasifier is of rather crude design and performs very poorly.*

- *Emissions Control (Baghouse /Stack Modifications) The existing stack rise 44" above the roof line. This does not provide any significant draft and also leads to the release of particulates and odours into the outside area around the physical plant. The stack height can be compensated for by the ID fan however the emissions require an emissions control device prior to the stack.*

- *Emergency exhaust / flare system to flare the syngas in the event of a problem with the B1 boiler or ID fan.*

Optimal

- *Minimize Cooling in Syngas Path to prevent excessive cooling of the syngas which could allow tars in the syngas to condense and eventually plug the ducts.*

- *New Air Distributor in the Gasifier as the existing distributor is bulky and reduces mixing in the bed.*

- *Bed Solids Handling Systems for bed ash removal or sand addition during operation. In the case of upset conditions, sand may be blown out of the system. This material must be replaced in order for the fluidized bed to function properly. Without an ash withdrawal system larger particles will accumulate and eventually necessitate a shutdown for their removal.*

- *An ID Fan Speed Controller to reduce power consumption and also allow sealing of the dilution air ports in B1 boiler*

The economic evaluation of operating the gasifier obviously ties into the costs of carrying out these modifications. The cost of changes will be in range $250k for required and recommended changes with the least expensive option for emissions control ($50k). The full optimized refurbishment of the gasifier with the most expensive emissions control (electrostatic precipitator) would be in the range of $550k.

An economic evaluation of operating the gasifier obviously ties into the costs of carrying out the recommended modifications from the 2004 report “Technical Evaluation of Yukon College Gasifier”. Although “ballpark” figures for these modifications were provided in 2004, further research and discussion was required in order to complete any economic justification. In the summer of 2008, a new study was commissioned by Yukon Energy Mines and Resources to address the detailed economics for the changes recommended in 2004, with emphasis on reactor re-design, process control and emissions control. Further discussions regarding: a new feed system, the use of alternative fuels and the research capability of the system were also to be provided to shed light on the future potential for the gasifier system.

The objectives of this study were to:

- Build upon the pre-design report prepared by CANMET, “Technical Evaluation of Yukon College Gasifier”, December 2004, to complete a schematic/preliminary design report with ASTM Level 3 cost estimates to address the technical improvements needed to commission and operate the gasifier at Yukon College, including but not limited to the following aspects of the project: Operating Controls; Emission Controls; Fuel Feed System; Safety

Requirements. Costs of recommended work were to be estimated to an ASTM Level 3 (-15% to +20%) for each of these aspects of the work.

- Model greenhouse gases and other emissions (sulphur oxides, nitrogen oxides, particulates, etc.) that would result from operating the gasifier in the configurations recommended and compare with typical emissions from the existing oil-fired and electric boilers currently in use in Whitehorse.

- Specify the characteristics of wood fuel required to operate the gasifier, including but not limited to: moisture content, calorific value, particle dimensions (maximum length of chip and maximum percentage of fine material), and ash content.

- Assess, in consultation with the Forest Management Branch of Yukon Energy, Mines & Resources, the future suitability to determine the potential of the following resources as secure supplies of biomass fuel: standing beetle-killed trees; fire-killed trees; sorted urban waste streams from the City of Whitehorse; sewage sludge from the City of Whitehorse

- Assess the suitability of the existing fuel handling and storage system for the various fuels including storage infrastructure and scheduling of wood fuel delivery that would be required during periods of maximum gasifier output.

In preparing a report to address the above issues, CETC was also requested to prepare an ASTM Level 1 estimate for

- options for using the gasifier as a tool for conducting scientific research at low, medium and high complexity levels
- economic feasibility/business case for production of power from syngas

For these options CANMET was to provide protocols specifying safety considerations, and risks and mitigation measures which would be applied to protect the equipment from damage during these types of activities. CANMET would also specify additional monitoring locations for temperature and pressure, as well as locations for sampling syngas and stack gases.

3 Gasifier System Modifications

This section details the necessary and optimal changes required to operate the system on a continuous basis. All of the modifications suggested in the "Technical Evaluation of Yukon College Gasifier" (Preto et al. 2004) report are addressed. Detailed discussions of: the gasifier system modifications, process control, emissions control, fuel system considerations and cost estimates for each of these areas are provided. The costs of these changes are based on quotes where available and in other cases as a result of discussions between equipment fabricators and CETC-O design staff. Quotes where used may be found in Appendix D.

The principal areas of re-design are the air pre-heat and distribution system, re-aligned feeder, ash removal system and in order to accommodate these changes the shortening of the exit pipe from the gasifier and the raising of the bottom of the unit by 30 inches. The well designed process control system is designed to ensure safety, increase efficiency, be highly automated, easy to trouble shoot and be an effective research tool. The emissions control for the system requires an add-on particulate removal system. The three types of equipment that are discussed include a: venture scrubber, electrostatic precipitator, and a wet electrostatic precipitator. The theory of these removal techniques, their benefits, prices and their ability to meet potential regulations are evaluated in this section. The fuel system that currently exists is prone to jamming with fuel that is not within specification. What fuel requirements should be met including: size, calorific value and ultimate analysis are outlined. An analysis of alternative fuels, such as, sewage sludge and municipal solid waste is provided. Four new fuel handling systems, one for pellets and three for wood chips are discussed emphasizing on-site storage, handling and cost.

3.1 Fluidized Bed System Re-Design

The gasifier is a 36" ID 170" high refractory lined (est. 8" thick) vessel with a reduced diameter vertical duct extending the total height to 202". Based on the nominal air supply of 650 SCFM and an operating temperature of 700 ^{o}C this translates into a superficial fluidizing velocity of 1.7 m/s, which is within the normal range for a bubbling fluidized bed with coarse sand.

The reactor re-design is focused on the lower section of the bed, where the air enters the system, and ash and bed material is removed. The system currently has only a manual ash removal system. In the 2004 report it was sited that "without an ash withdrawal system these larger particles will accumulate and eventually necessitate a shutdown for their removal" (Preto et al, 2004). The air distributor itself was described as bulky, which reduced air mixing in the bed and prevents agglomerates (clinkers) from dropping to the bottom of the bed. Reduced bed mixing produces poor carbon conversion and hot/cold spots within the fluidized bed.

Other system modifications include: adding an emergency exhaust system, increasing insulation along the syngas path to the B1 boiler, reconstructing the syngas diffusers at the B1 burner head and the closing off of holes at the end of the B1 boiler with an associated dilution hood vented to the outside, in order to prevent spillage of syngas into the heating plant space.

3.1.1 Elevation and Support

To implement the desired reactor modifications, the long duct extending from the top of the unit will need to be removed and the air and feed ports disconnected, so that the whole fluidized bed can be elevated. Once elevated, the system will need to be supported to allow for safe working conditions around the unit. The existing bottom section will be removed and replaced with the CETC-O design. The price estimate for lifting and stabilizing the unit was provided by Golden Hill Ventures, Whitehorse at a cost of $26,000.

The re-designed bottom section and ash withdrawal requires more height than the existing design. To allow for this height, the exit pipe extending from the top of the gasifier vessel will be shortened by approximately 30 inches prior to being reattached to the unit. The feed system will be re-aligned by straightening the fuel path in order to minimize plugging. These changes are illustrated in Figure 2.

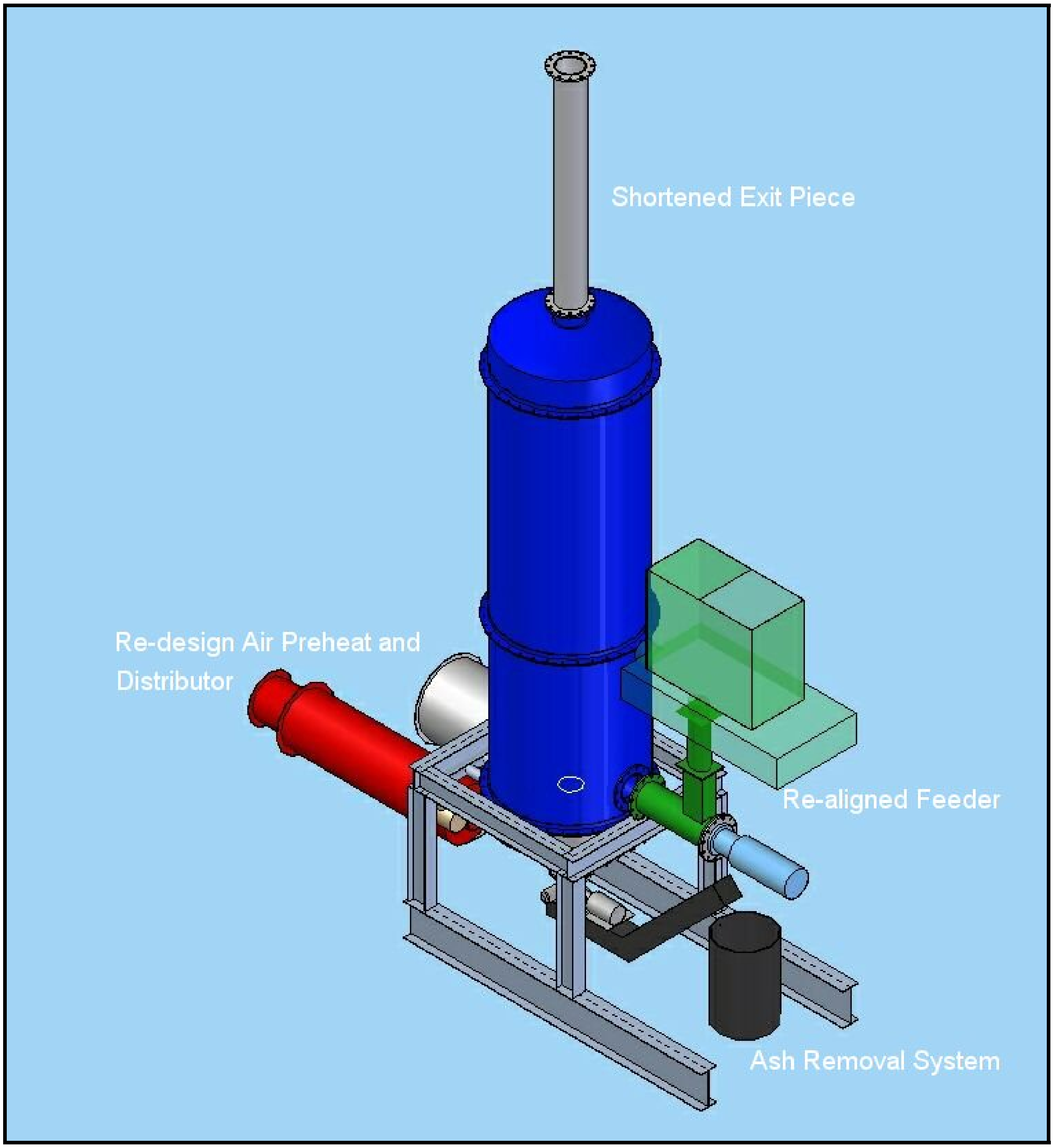

Figure 2 Modifications to fluidized bed gasifier

New feed and air ports will be cored into the reactor above the new bottom section, which based on coring through the ¼" steel of the fluidized bed and an estimated 10" of cast refractory will cost $600 per 10" hole. Flanges and gaskets will be incorporated onto the feed and air entry ports of the reactors for ease of maintenance. The four flanges and 10" pipe for these connections have been estimated at $2,684. Further, an additional clean out port will be added to the section above the new bottom at a cost of $845. The feed system will be slightly further away from the body of the reactor once it is moved. The feed screw leading into the unit will need to be replaced with one that is 10" longer than the existing screw. The air pre-heater system will also need to be moved up to the proper elevation so that the air manifold is in-line with the bed. The re-alignment changes have been estimated at $13,644. It is recommended that the components of the air pre-heater and the new ash removal be movable for ease of maintenance. Hydraulic carts and jacks to accomplish this task will cost $4,161. The total cost of elevating the unit, adding the access ports and re-aligning the auxiliary systems has been estimated at $48,535.

3.1.2 Pre-Heat Burner

The existing pre-heat burner is an oil system with a crude design consisting of a small pilot flame and an oil pipe for the main flame. In the 2004 report, the oil pre-heat burner was a "strongly suggested modification". This recommendation was based on poor emission from the burner and odours from the system that filled the boiler house.

A commercial burner with a built in burner management system, containing the required safety controls is recommended. The Beckett CF1400 commercial burner would meet the requirements of the system. It operates in the range of 4 to 13.6 gph or 560,000 to 1,904,000 BTU/hr input, which would be satisfactory for preheating the unit to the required 650^{o}C. In discussions with the Beckett Burner Technician Trainer, it was suggested that this burner equipped with a 45 degree nozzle would fit into the existing air pre-heat chamber.

The burner was priced with a flange kit, so that it will fit the existing infrastructure of the pre-heater. Griffiths Heating & Sheet metal Ltd, Whitehorse, estimated the materials to cost $2,507. The company did not confirm an installation price, therefore, an estimate of a technician and helper for two days was included, which totals $2,640. The total estimated cost of this system is $5,147.

3.1.3 Air Distributor

The new air distribution system which consists of four sparge tubes (horizontal tubes with small holes on the underside spaced so as to ensure uniform distribution of air throughout the fluidized bed). This system is illustrated in Figure 3 will replace the existing lower portion of the unit and will substantially reduce the internals in the fluidized bed thus freeing up space and considerably improving mixing in the bed. The sparge tubes will also allow clinkers and or "rocks" (i.e. from feed contaminants) of up to 4" to pass through the gap in the tubes and pass below to an automated ash removal system. The redesigned bottom section of the bed is conical, (Figure 3.) which will allow for automated ash removal through a central port. The bottom section will also contain cooling tubes which will cool the ash so that it exits the bed at essentially room temperature. The two new sections shown in Fig.3 will be insulated with Fibre Cast HM3100 Special KK which is a 60% aluminum, mullite based, low cement castable refractory. The detailed chemistry, temperature and pressure specifications are given in Appendix D.

The cost of fabricating the sparge tubes, manifold, and duct, cone with the "Y" anchors for the refractory and cooling tubes in place is estimated at $16,471. The refractory insulation will cost $6792 plus $7500 for installation. The total cost of the new bottom section is thus estimated to be $38,651.

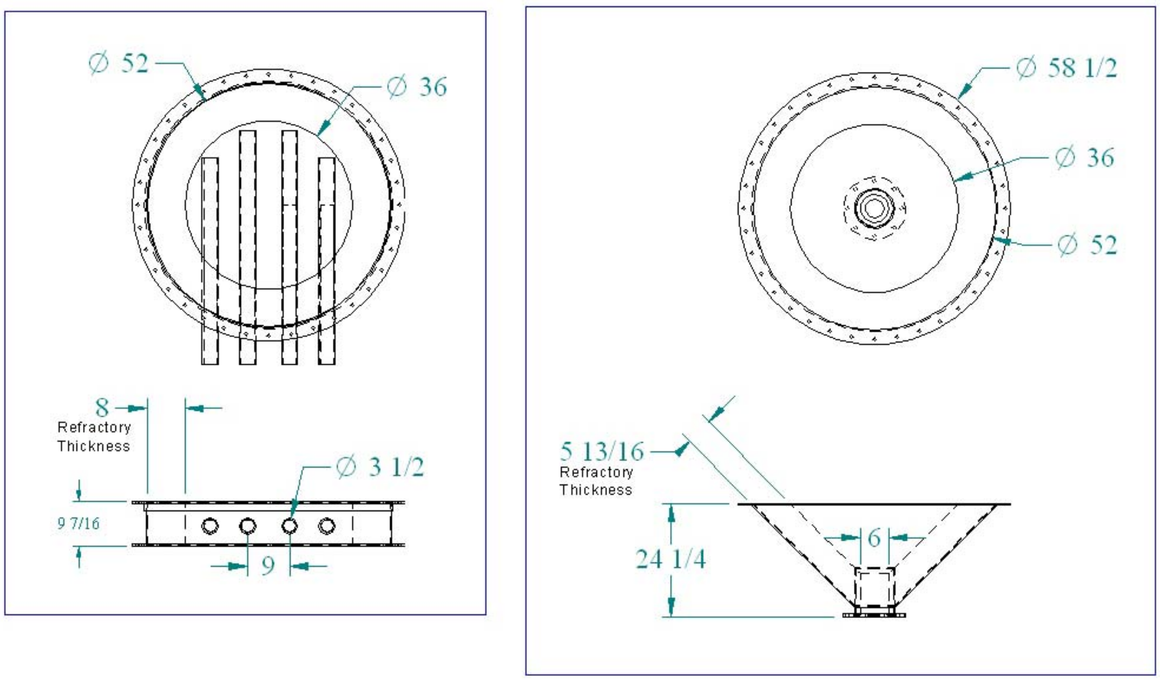

Figure 3 Air distribution design

3.1.4 Ash Cooling and Removal

In order for the gasifier to operate on a continuous basis, including continual removal of bottom ash from the unit is a necessity. Virgin wood chips have less than one percent ash, therefore only a few kilograms per hour of ash will be produced. Some bed material will also be removed during this process. New bed material would have to be added using the feed hopper, when the fluidized bed level declines.

As discussed above, the new bottom section will be conical to assist in ash removal and will be water cooled (Figure 3). The bottom ash and bed material will exit the reactor through a 6" stainless steel rotary air lock. The ash will deposit onto a covered conveyor that will lead to another covered inclined conveyor that empties into a barrel as outlined in Figure 4. The barrel would need to be emptied on a daily basis. This will also allow for an opportunity to inspect the bottom ash being produced by the system.

The cost estimate for the dual conveyor system ($16,550) plus installation ($2,640) is $19,190.

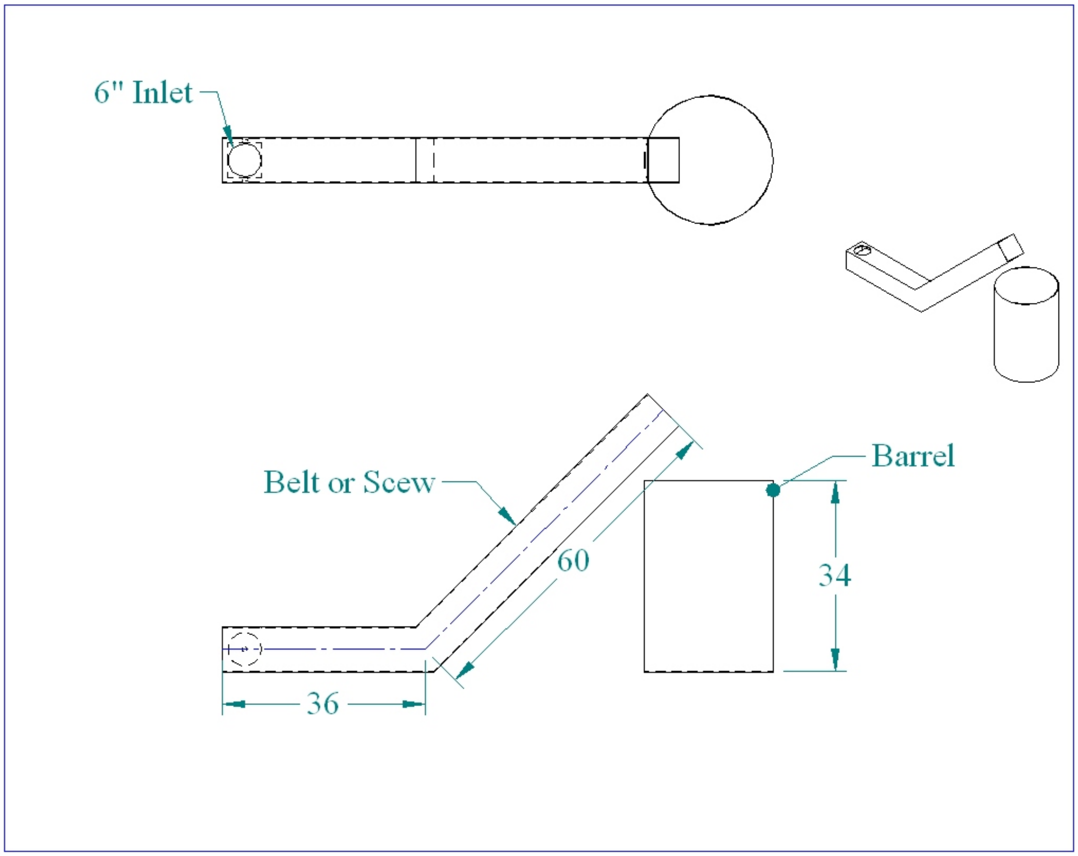

Figure 4 Ash removal system schematic

3.1.5 Emergency Exhaust

An emergency exhaust has been included in the system design to safely exhaust gases in case of a power failure, or any problems in the B1 boiler. The new piping would be located after the cyclones and exit the building through a stack to a point 40’ above the ground. The syngas produced by the gasifier has a low calorific value, which would make it difficult to combust in a flare. Tornado Tech Flare Systems of Alberta, Canada was consulted to evaluate the flare requirements. Their assessment recommended “a vent stack based on the data provided, as we believe that this is the most feasible option available for you. The waste gas stream is not readily combustible, and in order to bring the waste gas up to 20 MJ/m3, approximately 92,500 SCFH (~2.2 MMSCFD) of fuel gas would be required, which is a substantial cost.” Tornado Technologies Flare complies with the following standards and guidelines where applicable: Flare Design Guidelines: API 521, API 537; Construction Guidelines: ASME B31.1, API 537; Environmental Regulations: 40CFR60, AEUB Directive 060; Structural Standards: ANSI/ASC 7-88, &-97 & 7-98, National Building Code Canada

Tornado Tech Flare Systems performed a plume model calculation based on the expected syngas composition and concluded:

> *"In accordance with the allowable air quality standards you are allowed to produce a maximum CO ground level concentration of 15 mg/m3, and the Screen3 run shows that venting this stream would produce a maximum of 10.7 mg/m3, well within acceptable standards. Because this stream is not readily combustible and that a substantial amount of fuel gas is required to produce a combustible stream, we believe that the local governing authority will allow you to vent this gas. Please check with the local governing authority with regards to the legality of venting this gas."*

The data produced from the model is provided in Appendix D of the report. Tornado's cost estimate for the 4" diameter, 40' high emergency venting stack and mating base plate totals $11,310 plus installation costs of $10280. The total cost estimate of the emergency exhaust is thus $21,590.

3.1.6 Syngas Transport

There are currently two cyclones in place to remove ash from the gas stream. The first appears to have external insulation covered by cladding; however, the amount of insulation or refractory on the second cyclone is unknown. The flue gas path from gasifier to boiler is quite long, shown in Figure 5, which could lead to excessive cooling of the syngas. This cooling could allow tars in the syngas to condense and eventually plug the ducts. This section will need to be inspected to learn how much insulation currently exists and its condition.

The estimated cost for inspecting this section, removing the existing cladding and cleaning out the ducting and cyclone is $13,000. Re-assembly would take place with additional 3M Firemaster ceramic fiber insulation, stainless steel strapping and seals at a cost estimate for materials of $4,390 and $4,000 for installation. The total cost for the inspection and re-insulation of the syngas path is thus estimated at $21,390.

Figure 5 Syngas path to B1 boiler

3.1.7 B1 Syngas Diffusers

The boiler is equipped with a Fuel Master Burner Model CO-300 firing No. 2 fuel oil @ 400 psi with a minimum firing rate of 20 USGPH and a maximum of 90 USGPH. The burner has been configured for a high fire rate of 80 USGPH (3664 kW; 12.5 million Btu/h). The burner requires 20 amps and is configured for a furnace pressure of 0.5" W.C.

During the trial run in 2004, excessive heat was produced in the B1 boiler. This was attributed to an oversized oil pilot used for the syngas ignition source. This over firing created a safety concern as the exterior of the boiler reached temperatures of over 300 ^{o}C. A plasma ignitor with a supporting burner management system has been recommended as the pilot for the syngas. The syngas currently enters into the boiler through a vast array of lances that protrude into the boiler and surround the oil burner (Figure 6). These lances and their supporting manifold are severely corroded, as shown in Figure 7.

Figure 6 Oil burner and syngas introduction into B1 boiler

Figure 7 Corrosion on syngas distributors in 2004

The price of the plasma ignitor and the associated burner management system is included in the control system section of this report. The existing manifolds and lances will need to be removed prior to rebuilding the new system. The lances will be redesigned but essentially will consist of 70, 12 inch long 310SS pipe (3/4" schedule 40) sections capped by perforated 2" 310SS discs with perforations. The fabrication and installation of the syngas distributors, the cost of materials and welding stainless disks to cover the holes at the end of B1 is estimated at $20,980. Additional costs of $3,000 for patching the refractory within the boiler have been included, since this would complete the work on the B1 boiler. Updating this system was defined as a "required modification" in the 2004 report and the total cost estimate for the work is $23,980.

3.1.8 B1 Boiler External Dilution Hood

The back end of B1 boiler is open into the heating plant room. Sixty-four 1" holes provide dilution air for the flue gases, shown in Figure 8. This dilution air cools the flue gas prior to it entering the ID fan. As was demonstrated in the boiler tests reported in 2004, the system requires operation of the ID fan in order to ensure venting under high fire (or gasifier operation) conditions. In its current state, if the ID fan were to fail during operation, flue gases would spill into the room. Currently, if a power failure, or similar event, were to knock out the ID fan and the burner flame during gasifier operation, then raw syngas could spill into the room.

It is recommended to seal the holes at the back of the boiler with stainless steel disks. Consideration has been given to the addition of a dilution hood to bring in air form outside the building and prevent spillage into the boiler house. However, this will no longer be necessary as the addition of an emissions control device (e.g., ESP) will require relocation of the ID fan downstream of such a device. The additional ducting will provide most of the cooling and therefore an external dilution hood will no longer be required.

The cost of welding covers onto the holes at the back of the boiler was included in the estimate for fabricating the syngas distributors and the material for the caps would only add an additional $250 to this so the cost for all modification to B1 boiler (sections 3.1.7 and 3.1.8) will now be $24,230.

Figure 8 Existing dilution holes in the back of the B1 boiler

3.1.9 Fuel Storage (Existing System) and Handling

The current feed system is designed to transport chips from an outdoor underground bunker (Figure 9) through conveyor belts to a feed hopper. The current fuel storage in the underground bunker is roughly 60 m^3, which is enough space for about 13 tonnes of wood chips or 40 tonnes of wood pellets. Level sensors in the hopper automatically operate the conveyors to keep a minimum amount of fuel in the hopper. From the hopper, fuel is transported by a series of augers and airlocks into the fluidized bed. The feed rate is set manually by turning a large dial on the control panel. In 2004, the biomass feed system "appeared to be in good working order"; however, oversized woodchips jammed the feeding system from the outside bunker and terminated the run prematurely. In summary the findings of the 2004 were that the feed system is adequate, providing fuel specifications are met. The modifications being discussed in this report already include a re-alignment of the fine system to minimize jamming and no further changes (other than control systems which are included in Section 3.2) are required to the existing feed system other than inspection and verification. Fuel specifications and additional requirements are discussed in Section 3.5 of this report.

Figure 9 Receiving fuel in the underground bunker

3.1.10 Cost Estimate Summary

The detailed cost estimating that has been performed focused on having a clear plan for the design, while taking into consideration the location of the unit. The reactor redesign is focused on the lower section of the bed, where the air enters the system, and ash and bed material is removed. The cost break-down by task is provided in Table 4. The costs of all modifications are estimated as $205,136.

Table 3 Cost Summary Estimate for FB System Re-design

Fluid Bed System Re-design	
Elevation and Support	$ 48,535
Pre-Heat Burner	$ 5,148
Air Distributor	$ 38,652
Ash Cooling and Removal	$ 19,190
Emergency Exhaust	$ 21,590
Syngas Transport	$ 21,391
Boiler B1 Mods	$ 24,230
Refurbishment Labour	$ 26,400
Total	**$ 205,136**

3.2 Process Control

Previous attempts at operating the gasifier have highlighted the inadequacy of the control system. The control system lacks automation and even sensor capacity (e.g. air flow) to allow proper monitoring of the unit. A new control system including extensive temperature, pressure and air flow rate monitoring, as well as, burner management is required. A well designed control system will make the gasifier system safe, efficient, highly automated, easy to troubleshoot, and as an added bonus “an effective research tool”.

3.2.1 PLC Based Monitoring and Control System

The unit will be controlled using two Programmable Logic Controllers (PLC). These PLCs will collect and process the data coming from the various measuring devices. The PLCs will then control the process based on the incoming data to meet the heating system demand.

Sensors will be added to both the gasifier and the boiler in order to properly monitor and control the gasification process. Combination pressure/temperature ports in the gasifier will allow the operator to make a more accurate assessment of bed temperature, bed height, and amount of material in the unit. This combined with the characteristics of the fuel will allow proper control over the gasification process. The primary air flow through the preheater will be measured to optimize the air to fuel ratio in the gasifier. This will produce higher quality syngas, which will be monitored prior to entering the boiler. The oxygen content of the flue gas leaving the boiler will be measured and recorded to optimize boiler efficiency. Figure 10 shows the proposed process and instrumentation diagram.

The operator interface with the PLCs will be managed through two touch screen panels, with one panel located on each level of the facility. Remote monitoring and data collection will be done by a computer located in the control room. This computer will also provide data to off-site staff. A small local area network will be required for communication between the PLCs, touch screens, and data collection computer.

The new control system will allow for better overall system control. The logic programmed into the controllers will create a highly automated system that operates to obtain a high thermal efficiency within the system. Further, the increased data collection will provide information regarding system optimization and maintenance requirements. The collected data can also be used to characterize different fuels and ensure proper operation of the equipment.

3.2.2 Air Flow Measurement

Measuring the flow rate, temperature, and pressure of the primary air being delivered to the sparge tubes will allow the optimization of the burning conditions within the gasifier and minimize the amount of particulates in the syngas stream. The flow measurement will be done using an insertion type thermal mass flow transmitter. Variable speed drives will be used to set both the FD and ID fans in order to get more accurate flow rate control than is currently possible.

3.2.3 Burner Management Systems and Ignitors

A Burner Management System (BMS) will be used to ensure the safe ignition and combustion of the syngas. The BMS will be an integral part of the new safety system and ensures that the proper conditions are met before attempting to ignite the syngas. The BMS will also monitor the flame and take appropriate action should the flame go out. A plasma ignition system will be used to ignite the syngas in the boiler. This type of system is quickly becoming the norm in industry and will avoid excessive temperatures produced by running the boiler's burner as a pilot for the syngas.

3.2.4 High Temperature Limit

An emergency cooling system will be installed to ensure that the gasifier is quickly cooled in the event of abnormally high temperature excursions. The system will use a series of water jets triggered by a high temperature alarm to quench the reactions in the gasifier should the temperature reach a high limit.

3.2.5 Safety Measures

The safety of the individuals working with the gasifier, as well as those in the surrounding areas has been taken into consideration in the design of the modifications. The new control system will continuously monitor and record 44 parameters with redundancy for critical items. A two-tiered set of warning alarms (audible and flashing lights) and automatic shut off will be part of the control system. The alarm system will notify operators if a system parameter goes outside set boundaries. Emergency shut-off buttons will be installed on both levels of the boiler house to permit easy access for personnel. All alarms, alarm acknowledgments and actions taken will be recorded by the control system. Independently controlled air monitoring within the boiler house will consist of carbon monoxide, methane and hydrogen sulphide detectors. The potential for hydrogen sulphide formation is low especially given the low sulphur content of biomass

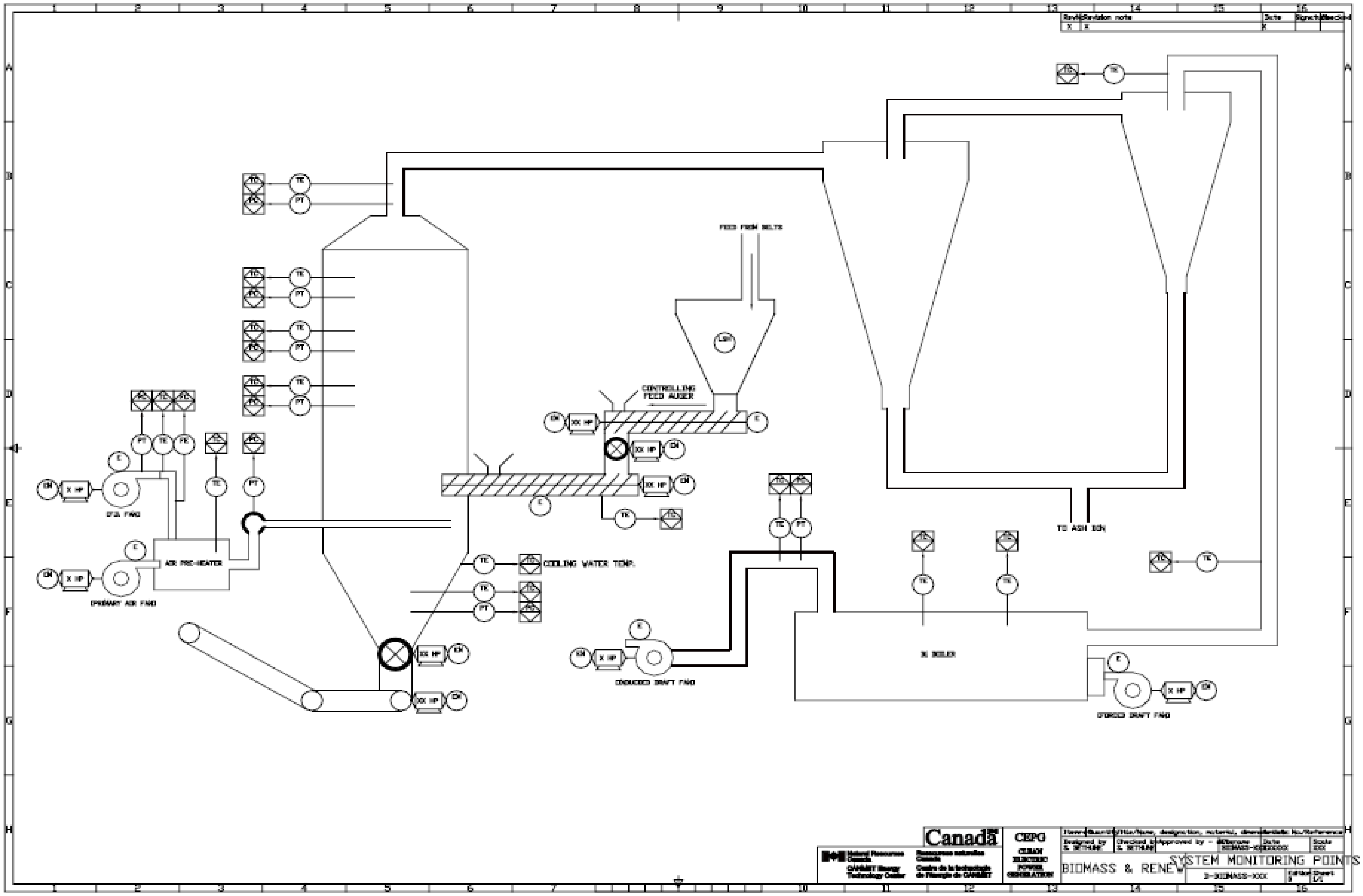

Figure 10 Gasifier System Process and Instrumentation Diagram

fuels, however given the small but still real possibility of hydrogen sulphide formation (especially if waste fuels are tested) it is recommended that hydrogen sulphide monitoring be included. The ambient air monitoring will operate independently but report to the gasifier control system for controlled shutdown in case of dangerous levels.

Safety Interlocks and Fail-safes

The various systems involved in the gasification process will be interlocked to avoid hazardous situations. The systems will also be set up to fail in a safe manner. In the case of a power failure, or failure of ignition within the boiler, the syngas will be vented to the exterior through the emergency exhaust system. An interlock hierarchy similar to the one below will be used to ensure proper shutdown in the event of a system failure. Failure in a specific system will shut down all of the systems below it in the hierarchy.

1. ID Fan
2. FD Fan
3. Bed Temperature (High and Low Limits)
4. Syngas Flame Ignition
5. Feed System

Gas Monitoring

Ambient gas monitors will be sensitive enough to detect gases before they reach harmful levels. Detection of any gases leaking into the facility will be detected early and corrective actions taken. Upon detection the system will automatically perform several operations including: the feed would cut out, the FD fan speed would increase to switch from gasification to combustion, the ID fan speed would increase to create a higher vacuum in an effort to keep the gasses from escaping the unit, and alarms would sound.

Gas analyzers will also be installed to monitor the composition of the syngas and the flue gas leaving the boiler. In addition to the safety aspect, syngas and boiler flue gas analysis will provide the operator with data regarding the efficiency of both the gasifier and the boiler and will aid in the optimization of the gasification process.

3.2.6 Cost Estimate Summary

The process control cost estimates have been based upon previous projects with similar size and scope of work, which have been recently completed at CETC-O. A detailed breakdown of the equipment can be found in Appendix B. Table 5 provides a cost list based on equipment type, with a total cost estimate of $220,045.

Table 4 Process Control Cost Estimate Summary

Controls & Data Acquisition	
Instrumentation	$ 17,590
Gas Analysis/Monitoring	$ 36,500
Cabling	$ 2,900
Control System/ PLC	$ 7,505
Burner Management Systems	$ 11,000
Control Panels	$ 11,500
Miscellaneous	$ 17,400
Labour	$ 115,650
Total	**$ 220,045**

3.3 Emissions Control

The addition of an emissions control device to the system was described as a "strongly suggested modification" in the 2004 report. Currently there are two cyclones following the fluidized bed to decrease particulate emissions. In addition, the low stack, which only extends 44" above the roof of the boiler house, leads to the release of particulates and odours into the outside area surrounding the plant. Three cost estimates for pollution control devices have been included in this report: wet scrubber, electrostatic precipitator (ESP) and Wet ESP (WESP). The design specifications used in order to obtain the quotations included decreasing particulate from 400mg/Nm^3 to 15mg/Nm^3. Since there was no obtainable historical data of the particulate loading after the cyclones, the estimate of 400mg/Nm^3 was used as a realistic assumption. The low emission of 15mg/Nm^3 was selected, since the client requested that this be among the lowest emitting systems in Canada. Currently, only waste incinerators in Ontario meet such low particulate emissions standards and Metro Vancouver is in the process of regulating to the next lowest level of 35 mg/m^3, due to its sensitive air shed. Typically industrial facilities would be much larger than the unit at the college, which makes the economics of this level of removal much more favourable.

3.3.1 Emissions Regulations

The Yukon's Air Emissions Regulations (AER) require that a permit be obtained for a number of activities, including the "operation of equipment capable of generating, burning or using, according to the manufacturer's specifications, heat energy equivalent to or greater than 5 million BTUs/hour (~1.5 MWth)". Once it is determined whether a permit is required, the proponent (in this case Property Management, Yukon Government) would be required to apply for a permit under the AER. The permit application form can be found in Appendix C. Once the completed application is reviewed, then a permit will be developed which will include pertinent standards and other related requirements. Note that a permit under this category has not yet been issued in the Yukon, so there is no sample available. Researching similar requirements in other jurisdictions will be key in determining what air quality standards (ambient or source) would be included in our AER permit. Table 6 provides particulate matter limits that are in place in other jurisdictions.

Table 5 Particulate Matter Emissions Regulations

Jurisdiction	Particulate Emission Rate (mg/m3)
Ontario (virgin wood)	90
Ontario (waste)	20
British Columbia (current)	180
British Columbia (proposed)	50
Metro Vancouver (proposed)	35
Alberta	70
Quebec	200
New Brunswick	125
USA	57

An assessment under the Yukon Environmental & Socio-economic Assessment Act (YESAA) may also be required (Part 11(2)). The Act sets out a process to assess the environmental and socio-economic effects of projects and other activities in the Yukon or that might affect the Yukon (www.yesab.ca). Note that if an assessment is required, an AER permit cannot be issued until that assessment has been completed.

3.3.2 Background

Cyclone mechanical collectors, which use gravity and centrifugal forces to remove particulate, are often used to control particulate emissions on biomass boilers. Usually, two cyclones are used in series to improve collection efficiency - the first removes the majority of coarse particles and the second removes the smaller particles. Typical cyclone separation efficiencies range between 85-95% (van Loo and Koppejan, 2002).

Wet scrubbers inject small water droplets into the flue gas where the water collides with the particulate, wetting the particles. The “wet” particulate is then carried away with the water. Venturi scrubbers, which are the most commonly used scrubber for wood-fired boilers, have reported particulate collection efficiencies of greater than 85% (US EPA).

If high collection efficiencies are required, Electrostatic Precipitators (ESPs) are used. ESPs remove particulate by electrically charging the particles which are then attracted to an electrode. Periodic vibration removes the particulate adhered to the electrode. When applied to wood-fired boilers, ESPs are often used downstream of mechanical collectors which first remove large particles. ESPs operating on wood-fired boilers have demonstrated collection efficiencies of 90 to 99% (US EPA).

Fabric filters (i.e., baghouses) have the potential to provide particulate control efficiencies of more than 99% (van Loo and Koppejan, 2002); however, their use with biomass fuels is limited due to the fire risk caused by the collection of unburnt fuel particles on the filter. This hazard can be reduced by the installation of a mechanical collector upstream of the fabric filter.

NO_x emissions result from the oxidation of the nitrogen in the fuel (fuel NO_x) and the combustion air - when the temperature is above 1300°C (thermal NO_x). Generally speaking, biomass fuels have lower fuel nitrogen content and biomass combustion occurs at lower temperatures than fossil fuels. As a result NO_x emissions from biomass combustion are typically lower than fossil fuel combustion (with standard burners). Currently, the primary method of reducing NO_x is through staging the combustion. If a further decrease in NO_x emissions is required, add-on methods are necessary. Though not commonly used on biomass boilers, selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) are widely used on fossil fuel fired furnaces to reduce NO_x emissions. In both methods, ammonia is injected into the flue gas to convert NO_x to nitrogen and water. An installation of SNCR provided up to 75% NO_x reduction on a wood-fired boiler (US EPA). The application of SCR to biomass boilers is currently limited by technical barriers.

SO_x, mainly SO_2, are caused by the oxidation of sulphur contained in the fuel. As wood contains little sulphur, SO_x emissions from wood combustion are low. Fuels such as straw and grasses contain quantities of sulphur which require SO_2 emission control measures to be used. The most common SO_2 reduction method is via flue gas scrubbing. Alkaline particles injected into the flue gas either alone (dry scrubbing) or mixed with water (wet scrubbing) react with the gas to remove SO_2. Wet scrubbers remove 80 to 95% of the SO_x and dry scrubbers, 70 to 80% (Amec, 2002).

Air pollution emissions from a given type of facility can be estimated using emission factors. Emission factors are averages of available data and are generally assumed to be representative of long-term averages for all facilities in a given source category (US EPA). Emission factors are not to be used as emission limits or standards.

Emission factors are contained in the document “Compilation of Air Pollutant Emission Factors, AP-42"(US EPA). The chapter applicable to large scale biomass combustion is chapter 1.6 “Wood Residue Combustion in Boilers.” The type of fuel is limited to wood residues - bark, combined bark and wet wood, wet wood (moisture >20%) and dry wood (moisture <20%). Tables 7 and 8 outline the emission factors for wood residue combustion as described in chapter 1.6 of AP-42.

The following items should be noted with respect to the information presented in the Tables 7 and 8. Analysis of the data used to determine the emission factors in AP-42 found that particulate emissions from boilers outfitted with control devices with high collection efficiencies were not affected by fuel type or moisture content (Eastern Research Group, 2001). Also, the data used to develop the NO_x emission factors were from units which had no emissions controls. SO_2 emissions were found to be mainly affected by the sulphur content of the fuel and not the fuel moisture content, the combustion technology or particulate control technology.

Table 6 Particulate Emission Factors for The Combustion Of Wood Residue

Control Device	Fuel Type	Emission Factor (mg/MJ)
Uncontrolled	Bark/Wet Wood	241
	Wet Wood	142
	Dry Wood	172
Mechanical Collector	Bark	323
	Bark/Wet Wood	151
	Wet Wood	95
	Dry Wood	129
Wet Scrubber	All Fuels	28
ESP	All Fuels	23
Fabric Filter	All Fuels	43

Note: Emission factors are averages of available data and are generally assumed to be representative of long-term averages for all facilities in a given source category (US EPA). Emission factors are not to be used as emission limits or standards

Table 7 Emission Factors For Residue Wood Combustion

Pollutant	Fuel Type	Furnace Type	Emission Factor (mg/MJ)
NOx	Bark/Wet Wood	All	95
	Dry Wood	All	211
CO	All Fuels	All, except FBC	256
	All Fuels	FBC	75
SO2	All Fuels	All	11
VOC	All Fuels	All	16

Note: Emission factors are averages of available data and are generally assumed to be representative of long-term averages for all facilities in a given source category (US EPA). Emission factors are not to be used as emission limits or standards

As has been noted, the principal emission which must be controlled for the fluidized bed gasifier is particulate matter and the processes which have been considered and priced include a: Venturi scrubber, electrostatic precipitator and wet electrostatic precipitator.

3.3.3 Venturi Scrubber

Venturi Scrubbers comprise of a convergent inlet section, constricted throat followed by divergent outlet section, shown in Figure 11. The scrubbing liquid is fed into the inlet section tangentially through a number of pipes & ensures that the entire surface area of section is flooded with scrubbing liquid. The dust laden gas enters the scrubber vertically from the top and immediately hits the film of scrubbing water where some separation takes place. The gas then enters the Venturi throat which has annular shape. This ensures that the highest possible volume of water is taken up by gas, which becomes saturated in this area. At the narrowest cross section of throat there is a sharp tear off edge where because of sudden change in gas speed the scrubbing water is atomized into tiny droplets. Because of high relative speed between the gas / dust mixture & the droplets the dust particles strike the droplets at high speed & are entrained by them. Although Venturi scrubbers can theoretically achieve the 15 mg/Nm^3, in practical terms, this outlet concentration is at the very limit of what can be expected of this type of device. A realistic outlet concentration for the Yukon College Gasifier is less than 35 mg/Nm^3.

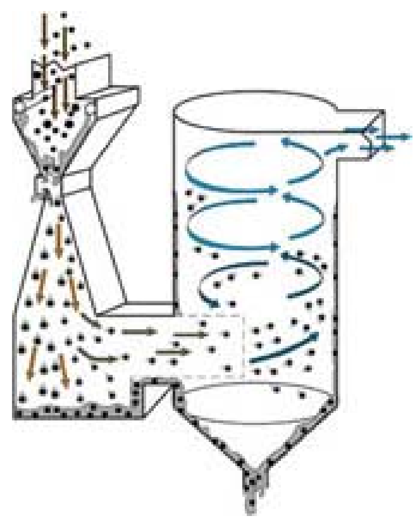

Figure 11 Venturi Scrubber Schematic

CETC-O approached TurboSonic Inc to provide detailed information and pricing for a Venturi design and this is shown in Tables 9 and 10. A complete description of the TurboSonic model is provided in Appendix D. The capital cost of the Venturi scrubber was estimated as $65,650 and an estimate of installation including recirculation pump, support steel and access platforms, instrumentation, piping and stack was an additional $35,000 for a total cost of $100,650.

Table 8 Venturi Scrubber Equipment Supply List

TurboVenturi	
Quantity	One (1)
Configuration	Vertical Inlet
Throat	Variable with damper
Material of Construction	304L stainless steel
Bottom Type	Flooded elbow
Vessel Height (ft)	6'-4"
Vessel Diameter (ft)	1'-0"
Separator	
Quantity	One (1)
Configuration	Vertical up-flow
Material of Construction	304L stainless steel
Bottom Type	Conical
Vessel Height (ft)	8'-0"
Vessel Diameter (in.)	33"
Inlet Type	Tangential
Outlet Type	Tangential
Integral Recirculation Tank	Yes
Options	
Access Doors	One (1) 24"H x 30"W
Access Platforms & Ladders	Internal access
Support Steel	Included
External Insulation / Heat Tracing	By others if required
Weight	
TurboVenturi Vessel (lb)	300
Separator Vessel (lb)	700

Table 9 Venturi Scrubber Design Operating Data

Pressure Drop		
Pressure drop across TurboVenturi	inches WG	20
Pressure drop across Separator	inches WG	3.0
Liquid Rates		
Scrubbing liquid		Recirculated water
Total flow	GPM	20
Flow – TurboVenturi tangential inlets	GPM	10
Pressure – Tangential inlets	PSIG	15
Flow – TurboVenturi throat inlets	GPM	10
Pressure – Throat inlets	PSIG	8-10
System Bleed		
Recommended flow rate	GPH	9.3
Dissolved Solids concentration (Rec. Flow)	% w	3
Evaporative Loss	GPH	25.3 estimated
Water Make-up Rate (at Specified Bleed)	GPH	34.6 estimated

3.3.4 Electrostatic Precipitator (ESP)

An Electrostatic Precipitator (ESP) removes particulate matter from a gas stream by creating a high voltage drop between electrodes, shown in Figure 12. A gas stream carrying particles flows into the ESP and between sets of large plate electrodes; gas molecules are ionized, the resulting ions stick to the particles, and the particles acquire a charge. The charged particles are attracted to and collected on the oppositely charged plates while the cleaned gas flows through the device. While the gas flows between the plates at velocities in the range of 1 to 3 meters per second, the particles move towards the plates at a velocity (called the drift velocity) that is in the range of 1 to 10 meters per minute. During the operation of the device, the plates are rapped periodically to knock off the layer of dust that builds up. The dust is collected dry and can be disposed of or recycled.

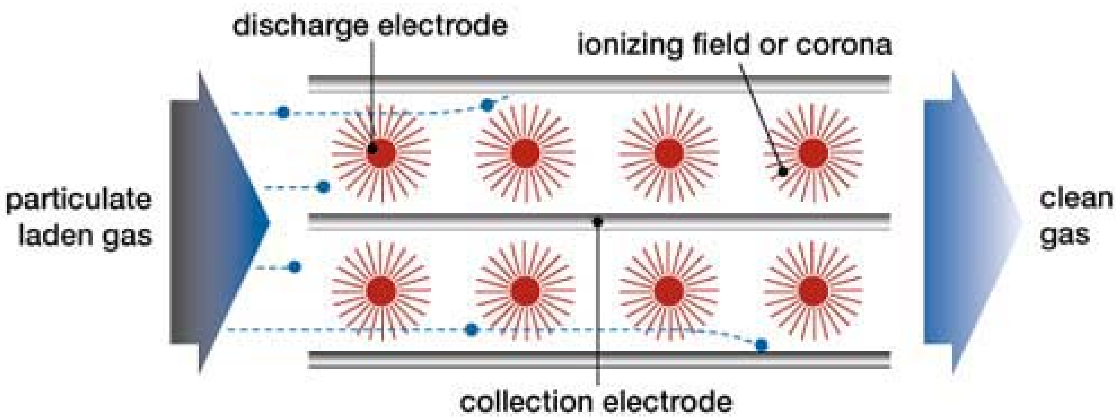

Figure 12 Electrostatic Precipitator Schematic

ESPs are large and very expensive to buy, but have the important advantage that they collect particles with very high efficiencies. Unfortunately, ESP efficiency drops off substantially for small units and whereas emissions below 15 mg/Nm^3 are common for power plant and pulp mill scale units, for units in the size range of the Yukon College Gasifier, the emissions guarantee will likely be 30 mg/Nm^3.

CETC-O contacted PPC Industries for a suitable ESP and they suggested their Model S3-820-1S. The unit is designed to operate at 2,300 acfm and 356° F. The unit is designed to operate at a gas velocity of 2 ft/s. The gas produced by the flue gas in this system would result in a gas velocity of ~ 1.5 ft/s, and therefore, PPC Industries would only guarantee a particulate emissions level of 30-35 mg/Nm^3.

The PPC Industries supplied unit would include the collecting module, structural steel supports, longitudinal trough hopper with a 9" integral conveyor, 8" airlock, and one transformer with a microprocessor controller mounted at grade, pyramid inlet nozzle, box outlet nozzle, 23' discharge elevation stub stack mounted on the outlet nozzle and shop installed thermal insulation for a price of $327,000. Installation has been estimated at an additional $35,000 for field erection, electrical wiring and grounding. The total estimated cost of the ESP option is therefore $362,000.

3.3.5 Wet ESP

In Wet Electrostatic Precipitator (WESP) particulate control systems the gas enters round collection tubes, which are bundled, between two tube sheets in a honeycomb type arrangement. Above the collection tubes are two sets of spray headers. The first spray header continually mists the collection tubes with small water droplets, which are immediately charged and flow down the tube, in the direction of the gas flow. This continually wets the tubes to prevent sticky particulates from adhering to the tubes during the particulate control process. The second spray header is the flushing header, which periodically sprays a larger amount of water to flush the collected precipitate out of the collection tubes into the lower plenum, during the particulate control process.

In the middle of each WESP collection tube is a rigid pin corona-generating electrode. As the dust and aerosol particles enter the collection tubes they become charged from a bombardment of negatively charged electrons. The negatively charged particles adhere to the wetted collection tube and are periodically flushed into the electrostatic precipitator's lower plenum. The lower plenum is designed to demist the gas stream and drain all of the collected precipitate to the collection system, completing the particulate control process.

Essentially a WESP is a combination of scrubber and ESP and the combination of the two effects ensures that the WESP can achieve particulate levels of 15 mg/Nm^3.

CETC-O contacted Turbo Sonic and they confirmed that their WESP could indeed achieve 15 mg/Nm^3 (Tables 11 and 12). The cost however was substantially higher at $399,600 for the equipment and $75,000 for installation including support and access platforms and stack. The total estimated cost for a WESP would therefore be $474,600.

Table 10 Wet ESP Equipment Supply List

Equipment	
Model	SonicKleen™ WESP-316L-7-12H18
General Information	
Orientation/Flow Direction	Top inlet, vertical downflow
Inlet Gas Flow Distribution Type	Multiple perforated plate distribution
Emitting Electrode Design	SonicCharge ™ rigid mast
Collecting Electrode Style	12" hexagonal tube
Particulate Removal Design	Self forming film, gravity drain
Inlet / Outlet Plenum	
Temperature Design Max.	300°F
Pressure Design Max.	+/- 20 in. wg
Plenum Material/Stiffener Material	316Lss / 316Lss
Tube Bundle (collecting electrodes)	
Tube Quantity	7
Tube Length (ft.)	18
Shell Material/Tube Material	316Lss / 316Lss
High Voltage System	
Electrode Suspension Frame	Qty (1) 316Lss frame c/w heavy duty channel support beams
Insulator Type/Material/ Qty Per Frame	Conical "flowerpot" style/Alumina/3
Electrode Support	Top support only – no lower alignment frame
Electrode Alignment Mechanism	Individually adjustable
HV Connections	Flexible Connector
HV Power Supply	Qty.(1) NWL Power Plus™ Series resonant switch mode
Rectifier	3 ph full wave/DC Bus/high frequency AC/DC
Insulation	Mineral oil
HV Controls	GVC (graphic voltage control) display or equivalent.
Insulator Compartments	Integral plenum mounted, bolted access hatch
Insulator Compartment Heating System	
Insulator Heater	2 x 500W electrical resistance heater
Insulator compartment Temperature Control	Temperature controller w/ SCR based power controller
Flushing System	
Flushing Controls	Controlled by local control panel
Flushing Rate	1.0 USgpm/tube; 2 min/ 8hr min
Accessories	
Key Interlocks	Key locks Kirk or equal - doors, T/R, HV controller
Access Doors	Inlet/outlet plenum access, quick opening doors
HV Warning Labels	Included
Maintenance Grounding Rod	Included
Dimensions	4'-2" dia x 32'-0" High
Weight	20,390 lbs

Table 11 Design Operating Data

Design Parameters		
Pressure Drop across WESP	inches WG	1.5
Gas Throughput Velocity	ft/sec	5.5
Gas Retention time	sec	3.3
Effective Specific Collecting Area	SCA ft2/1000acfm	217
Recirculated Water		
Flushing (average)	GPH	3.6
Flushing (max. instantaneous)	GPM	21 (intermittent flushing 2 minutes every 6 hrs)
Electrical		
Precipitator – Transformer/Rectifiers	Qty	1
Primary Power	(V/PH/HZ)	575/3/60
Connected	kVA	3.8
Demand	kVA	2.73
Consumed Power	kW	2.35
Heater Power Supply	(V/PH/HZ)	575/3/60
Connected Power	kW	3
Consumed Power	kW	1.5

3.3.6 Flue Gas Exhaust System

The ID fan would be relocated after any air pollution control devices added onto the system to bring the flue gas from the B1 boiler through the emission control device and out the stack. Duncan’s Ltd., Whitehorse was request to quote the cost of supplying and installing a 24” diameter pressure chimney with 2” thick insulated sections. Including reworking the existing ID fan discharge connections and installing the vent to connect to an emissions control device, located on site by others, the budget price is $92,000

3.3.7 Emissions Comparisons

The gasifier will be much lower in emissions than conventional wood combustion systems. Wood stoves generate particulates in the “hundreds of milligrams” per cubic meter of flue gas. A good wood furnace in the range of the gasifier will emit particulates in the 50 to 200 mg/m^3 range depending on the emissions control technology. With a well designed system using a scrubber or ESP this system will definitely be below 50 mg/m^3. The addition of two scrubbers, one for the syngas and one for the flue gas after the boiler, will likely reduce particulate below 15 mg/m^3.

For comparisons sake a No. 2 fuel oil-fired system (well tuned and cleaned) will typically be emitting particulate in the 10 to 20 mg/m^3 range. However no.2 oil has much higher sulphur than wood and so the SO_2 emissions can be as high as 4000 ppm as compared with at most a couple of hundred for the wood gasifier. No. 6 fuel oil (Bunker C) is much worse than no. 2 on all counts. With a well tuned particulate emissions control system this gasifier will perform at the same level as a well tuned oil furnace and much better than a wood stove. In terms of sulphur emissions the gasifier will be at least a factor of ten better in terms of sulphur dioxide emissions. Table 13 provides emissions data from various systems to allow for a comparison.

Table 12 Emissions Comparisons

	Size	Fuel	PM (mg/m3)	CO (ppm)	SO2 (ppm)	O2 (%)
Wood Stove (Residential)	50kWth	BC Fir	200	1900	2	6
Wood Chip Grate Furnace* (Industrial)	6 MWth	Virgin Wood Chips	130	100	18	10
Oil Burner (Residential)	30 kWth	No. 2 Fuel Oil	11.6	19.5	109	3.9
Oil Burner (Commercial)	150 kWth	No. 2 Fuel Oil	18.9	21	105	4.3
Oil Burner (Industrial)	7 MWth	No. 6 Fuel Oil	140	NA	573	4.2

* Particulate was measured after a multicyclone

3.3.8 Cost Estimate Summary

There are a number of options which can be implemented in order to control emissions, namely particulate emissions. Control of particulate emissions will however require a secondary or external device. Owing to the small size of the gasifier, improved performace is between the equipment is not as noticeable. Table 14 provides the cost of the equipment and the expected particulate emissions (mg/m3). Since all of these options require the relocation of the ID Fan and a new chimney pipe leading to the equipment ($92,000) the recommended option of the Venturi Scrubber would total $ 192,650.

Table 13 Cost and Specification of Emission Control Devices

Emissions Control		
Equipment	**Cost**	**Emission (mg/m3)**
Ventrui Scrubber	$ 100,650	35
ESP	$ 362,000	30-35
WESP	$ 474,600	15
Flue Gas Path/Fan Mods	$ 92,000	

3.4 Modification Cost Estimate Summary

The detailed cost estimating that has been performed focused on having a clear plan for the design, while taking into consideration the location of the unit. Shipping of equipment and travel expenditures of personnel to Whitehorse was estimated when supplies were not located locally. Both transportation fuel and steel are variable commodities that have had large increases in short periods of time; these two costs are estimated at the current rates available at the time of the reporting.

The reactor redesign is focused on the lower section of the bed, where the air enters the system, and ash and bed material is removed. Other system modifications include: increasing the fuel storage, adding an emergency exhaust system, increasing insulation along the flue gas path to the B1 boiler, reconstructing the syngas diffusers at the B1 burner head and sealing the end of B1 boiler to prevent release of syngas into the boiler room. The costs of all modifications are estimated as $205,136. A new control and monitoring system including capability for on-line syngas analyses, which will allow operation of the unit in both gasification and combustion modes was estimated at $220,045. The cost of the reactor and control system modifications to make the gasifier operational is thus $425,181.

There are a number of options which can be implemented in order to control emissions, namely particulate emissions. Other emissions such as NO_X and SO_2 are minimized by the fuel specifications and will not require additional control. An oxygen sensor has been included in the control for B1 boiler and this will allow proper control of excess levels in the boiler which will ensure that carbon monoxide levels are minimized. Control of particulate emissions will however require a secondary or external device. A number of options were considered:

- A Venturi scrubber at a cost of $100,650 with emissions of 35 mg/Nm^3
- An ESP at a cost of $362,000 with emissions of 30-35 mg/Nm^3
- A Wet ESP at a cost of $474,600 with emissions of 15 mg/Nm^3

Owing to the small size of the gasifier, the ESP performance is not superior to a Venturi scrubber, and therefore, the choice is between the scrubber and the Wet ESP. Given that the scrubber offers potential increased heat recovery from the scrubber water, and therefore, higher efficiency, unless there are regulatory requirements for the lowest level particulate emissions it is recommended that the gasifier re-capitalization project include the Venturi scrubber as the emissions control technology. This brings the total cost of the project without an additional fuel feed system to $617,831. The modification cost summary is broken down in Table 15.

Table 14 Complete List of Estimated Costs

Fluid Bed System Re-design	
Elevation and Support	$ 48,535
Pre-Heat Burner	$ 5,148
Air Distributor	$ 38,652
Ash Cooling and Removal	$ 19,190

Emergency Exhaust	$ 21,590
Syngas Transport	$ 21,391
Boiler B1 Mods	$ 24,230
Refurbishment Labour	$ 26,400
Section Total	**$ 205,136**
Controls & Data Acquisition	
Instrumentation	$ 17,590
Gas Analysis/Monitoring	$ 36,500
Cabling	$ 2,900
Control System/ PLC	$ 7,505
Burner Management Systems	$ 11,000
Control Panels	$ 11,500
Miscellaneous	$ 17,400
Labour	$ 115,650
Section Total	**$ 220,045**
Emissions Control	
Ventrui Scrubber	$ 100,650
Flue Gas Path/Fan Mods	$ 92,000
Section Total	**$ 192,650**
TOTAL	**$ 617,831**

3.5 Fuel Storage and Handling

This section provides fuel specifications that should be followed for the gasifier system. High fuel quality prevents system down-time and wear of equipment; further, air emissions are improved with higher quality fuel. An analysis of alternative fuels including sewage sludge and municipal solid waste is provided. New feed system options for the gasifier system are presented, discussed and priced; including three wood chip systems with various storage capacities and one wood pellet system.

Having reliable fuel handling is a critical component to sustaining the operation of a biomass system. An ideal system will be highly automated, address quality control of the fuel by screening out fines and over sized pieces and feed into the system as directly as possible. Having on-site fuel storage gives the operator more leverage to turn away loads of poor quality fuel. At maximum capacity the gasifier can potentially operate at up to 4-500 kg/hr or 12 tonnes of wood per day. Based on the estimate for the capacity of the existing storage bunker (~13 tonnes of chips) the bunker would have to be refilled on average once per day (including weekends and holidays). This would be reduced to essentially twice per week (40 tonne capacity) for pellets. If no changes are made to the fuel handling system, then it is recommended that the feedstock change from wood chips to wood pellets, which would not only increase fuel density but also ensure quality control.

The scope of work for this report was to evaluate a range of options for fuel feed and therefore three types of wood chip systems have been proposed to operate independently of the current system. The three systems are:

- a covered trailer feed bin with 50 tonne capacity (~ 4 days at max rate)
- a conveyor fed bin with 200 tonne capacity and (~ 2 weeks at max rate)
- a covered dual feed system with 120 tonne capacity (~ 9 days at max rate)

These designs have been priced with specific storage capacities in mind but these concepts could be redesigned for varied capacities. Some common elements are integrated into each feed system, such as, a concrete base, a screener to remove over sized pieces and fines, conveyors leading to the existing feed hopper in the boiler house and a tractor with a front end loader for moving fuel.

3.5.1 Fuel Specifications and Requirements

The recommended specifications for the fuel are:

Maximum dimension of 2”

Less than 5 % fines (particles < .5 mm)

Moisture Content[++]: 10 to 20%

Ash (and dirt): 0-1.5%

Heating Values: >18.5 MJ/kg on a dry basis

Ultimate analysis (dry ash free mass basis)

C 50-55.5%
H 6-6.5%
N <0.5%
S <0.05%

[++]: This moisture level is the recommended range for maximizing the energy content of he product gas. Moisture contents below 5% are acceptable but will significantly reduce the hydrogen content of the product gas. This figure is intended to be a general guide and the critical limit is that moisture should not exceed 20%.

Fuel with a large fines component is not suitable for the gasifier. The residence time of fines is much shorter than chips and therefore fines may not gasify properly and be carried out with the product gas, creating particulate problems.

Dirt and other non-combustibles such as rocks, metals (pop cans, etc.) and other foreign objects have the potential to adversely effect the operation of the gasifier and feed equipment. Magnetic metal removal system is an optional component to prevent the ingress of metals into the gasifier.

Biomass "Sustainability" and Standing "Dead" Tree Properties

Canada is a forest nation. Its forests cover 42% of its land mass and represent 10% of the world's forests and more than 30% of the Boreal Forest. Forests play an important role in the economic, social and spiritual well-being of Canadians. The majority of Canada's forests lie within eight ecozones delineated on the basis of the interactions of geological, landscape, soil, vegetation, climate, wildlife, water and human factors.

The Boreal Cordillera ecozone, covering sections of northern British Columbia and the southern Yukon, has a Pacific Maritime influence that moderates temperatures over most of its area. The climate is marked by long, cold winters and short, warm summers. The ecozone is 61% forested. Vegetative cover ranges from closed to open canopy forest. Tree species include white and black spruces, alpine fir, lodgepole pine, trembling aspen, balsam poplar and white birch. The tree line ranges from 1500 metres in the southeast to about 1200 metres in the northwest, where the stands are generally open, and there is almost no lodgepole pine or alpine fir. This ecozone is sparsely populated, with the majority of the population of approximately 32904 (density 0.1) residing in the larger communities of Whitehorse and Dawson. The major economic activity is mining followed by forestry, tourism, and hydroelectric development.

The mean annual increment (MAI) is the average net annual increase in the yield of living trees to a given age, and is calculated by dividing the yield of a stand of trees by its mean age. The MAI is dependent on a number of factors, including climate and elevation, soil conditions and forest management practices. MAI is a measure of the net biomass production of the forest in m^3/(hectare·year). For the Boreal Cordillera, the MAI ranges from 0.69 for poplar (Note: this is conventional poplar trees, not short rotation poplar which is under consideration in parts of Canada as an energy crop) to 1.57 for larch. The values (from Natural Resources Canada / Canadian Forestry Service (CFS) surveys) include 1.30 for spruce, 1.11 for pine, 1.46 for fir, 1.20 for hemlock and 1.17 for birch. In estimating how much forest area would be required for a given amount of energy, after discussions with CFS (Karau and Sidders, 2008) it was decided that a conservative number would be an MAI of 1.1 for the area around Whitehorse. For comparison purpose, spruce in the Pacific Maritime region have an MAI of 3.8. Based on the growth rate of 1.1 m^3/(hectare·year) an area of approximately 2 square kilometres would be adequate to sustainably supply all the fuel required by the Yukon College gasifier.

In addition to the annual growth of forest, there are two other factors affecting the potential for energy from biomass in the Yukon Territory: forest fires and spruce bark beetle infestations.

A forest fire kills trees and shrubs but often does not consume them; instead, it turns them into dead fuel. Combustion rarely consumes more than 10 to 15 percent of the organic matter, even in stand-replacement fires, and often much less. Consequently, much of the forest remains in the form of live trees, standing dead trees, and logs on the ground. Forest fires typically kill over 1000 square kilometres of forest in the Yukon each year. A considerable amount of biomass is therefore available to be used for energy systems.

The infestation of the mature spruce forests by the spruce bark beetle in the area around Haines Junction (Champagne and Aishihik Traditional Territory) has been epidemic since 1992. The infestation has contributed to a potential fire hazard for communities, increased the risk of catastrophic loss of property, affected visual landscapes, reduced the value of the forest for timber, recreation and tourism and impacted ecosystems. The scale of the infestation is extreme. Based on a forest health survey conducted by the Canadian Forest Service and the Yukon Forest Management Branch the infestation over the last 10 years has expanded its range and now occupies a total area of more than 220,000 hectares in the region. The annual rate of change in the amount of forest infested over this decade has been dynamic, but except for one three-year decline, the overall trend has been a growing increase. In some of the 18 planning areas in the region, the infestation has killed 100 per cent of the infested stands. This means that a potential area of 2200 square kilometres of dead forest is potentially available for energy use.

There are obviously opportunities to utilize fire and pest-killed trees for a variety of products. The value of these trees generally decreases over time due to factors, such as, checking and decay. However, these factors may be less critical when fire-killed trees are used as a source of biomass for the production of heat energy. Lieu et al. (1979) reported that the heat content of oven dry material from downed and standing dead western white pine and lodgepole pine was similar to that for material from green trees. Barnes and Sinclair (1984) reported similar results for a comparison of gross heat of combustion for living and spruce budworm-killed balsam fir. Studies carried out in Colorado (FPJ) on fire-killed trees from three separate years (1996, 2000 and 2002) showed that there was no significant difference between the heating value of living trees and fire-killed trees. Furthermore, the recoverable heat of combustion was higher for trees that had been dead longer, as a result of lower wood moisture content. The moisture content for samples from live trees averaged 77.8 percent, while trees killed after 1, 3 and 7 yeas averaged 39.1, 27.5, and 9.4 percent, respectively.

The exact mechanisms of decay of standing trees is not well understood and requires considerable additional work. Harmon (1982) reported decay rates by measuring density and for the Eastern U.S. showed decay rates of 0.02 to 0.07 $g/(cm^3 \cdot year)$, which translated into losses of ranging from 3.6% per year to 11% per year. These losses were extremely dependent on climatic conditions and for the Yukon would likely be in the lower end of this range. Trees deteriorate continuously after death thereby reducing both recovery volumes and values decrease with the amount of time that dead trees are left standing. The key factors for standing trees killed by fire or pests are ambient moisture and temperature. Water immersion can be used to control wood deterioration over time, however the economics of storing large volumes of wood in water are not compelling. A climate-based index for determining overall decay hazard in standing trees has been developed for a limited number of locales (Scheffer 1971) but shows large variation across the range of conditions throughout British Columbia.

The biggest value losses in dead trees are associated with handling. Dry, brittle trees are more susceptible to breakage—11% in four-year-dead trees versus 0% in live trees (Work

1978). The processes of falling, skidding, loading, hauling, decking and feeding mills involve handling the wood with large machinery, which result in significant breakage. Secondary problems with handling dead wood include safety concerns as brittle trees can easily break unexpectedly. Dry logs delivered to a sawmill also present difficulties in the processing stage. Debarkers tend to become less efficient when handling dry logs, because the dry fibre is easily damaged. Dry wood requires more energy to saw. Saws and chipper and planer blades blunt faster, in part because of dirt and stones lodged in wood checks. Checks formed due to severe drying of the wood result in splits in logs which open up and reduce board width and length. When checked lumber breaks during processing, pieces can jam sawmill and planer machinery, which leads to downtime and reduced productivity.

Burning wood for energy is often proposed as possible use for pest and fire-killed trees. Although domestic stoves, furnaces and fireplaces can make use of some logs, more promising options involve industrial production of fuel pellets, electricity and heat. Large, commercial-scale wood-pelletization plants already in operation in British Columbia's beetle-infestation area consume large volumes of residual fibre from other processing facilities. Unfortunately the potential for bioenergy from dead trees depends heavily on costs for production, not technical feasibility. Most literature points to feedstock costs as a critical factor in economic feasibility of biomass-energy production. In British Columbia, current pellet production depends on residual wood fibre delivered at little or no cost to production facilities. However, if direct salvaged beetle-killed lodgepole pine were used to procure wood fibre, costs of pellet production could potentially double or triple. Although there are cost and supply concerns, there are also benefits specific to bio-energy products. Fuel pellets offer several benefits over wood chips and other forms of combustible wood material: they are a stable product and have significant advantages in terms of transportation, storage and handling. Processing also reduces phytosanitary concerns associated with the output of "green" wood products. As transport costs of biofuels do not depend on type of product but primarily upon product bulk and moisture content, lower transportation and storage costs are achieved through compacting of wood fibre.

Clearly there is a need for further research to determine the exact nature of the changes in wood properties for standing fire and pest-killed trees; however, the major effects seem to be drying and embrittlement of the trees. In terms of energy content Figure 13 gives a general trend for net energy content with years following tree death. Harvesting in the 3 to 4 year time frame seems optimal for obtaining relatively dry wood which is still "safe and easy" to harvest.

Figure 13 Standing Dead Tree Energy Content

3.5.2 Alternate Fuels

The fluidized bed reactor was set up to provide heat to Yukon College, however, further uses for the system have been identified including the disposal of combustible wastes, such as, municipal solid waste and sewage sludge.

Several key contaminants should be monitored when incinerating waste materials to ensure that negative effects are not passed onto humans, animals and the environment. Table 16 provides the list of tests and methodologies used in the analysis for specific contaminants. These tests provide sufficient information to allow for a comparison to the incineration of waste guideline A-7, shown in Table 17. An update to the A-7 guideline was introduced in guideline A-8, which decreases the dioxin and furan limit from 140 pg/Nm^3 to 80pg/Nm^3. Large costs are associated with this level of testing and monitoring, which depending on the local authorities may be required annually.

Table 15 Test Contaminants

Test Contaminant	Sampling Method	Analytical Method
TSP / Metals	OSTC Method 5/ EPA Method 29	Gravimetric, ICAP
SVOC's	EPA Method 23	EPS 1/RM/3 HRMS
VOC's	EPA Method 31	EPA 5040/8760 GC/MS

Test Contaminant	Sampling Method	Analytical Method
Halogens/Halides (Cl, F, Br, HCl, HF, HBr)	EPA Method 50	Ion Chromatography, Spectrophotometry
Oxygen	Continuous Emissions Monitoring (CEMS)	
NOx		Zero and Span
SO2		instrument
CO		
Total Hydrocarbons		

Table 16 Emissions Limits from The A7 Guideline

Parameter	Emission Limit	Comments
PM[1]	17 mg/Rm^3	calculated as the arithmetic average of 3 stack tests
cadmium[2]	14 µg/Rm^3	calculated as the arithmetic average of 3 stack tests
lead[2]	142 µg/Rm^3	calculated as the arithmetic average of 3 stack tests
mercury[2]	20 µg/Rm^3	calculated as the arithmetic average of 3 stack tests
dioxin/furan	0.14 ng/Rm^3 as ITEQ[3]	calculated as the arithmetic average of 3 stack tests
hydrochloric acid (HCl)	18 ppmv (27 mg/Rm^3) or an HCl removal efficiency of not less than 95%	calculated as the arithmetic average of three 1-hour stack tests
sulphur dioxide (SO_2)[4]	21 ppmv (56 mg/Rm^3)	calculated as the geometric average of 24 hours of data from a continuous emission monitoring system
nitrogen oxides (NO_x)[5]	110 ppmv	calculated as the arithmetic average of 24 hours of data from a continuous emission monitoring system
organic matter	100 ppmv undiluted (expressed as equivalent methane)	required by Section 12(2) of O.Reg. 346

(Standards Development Branch, 2000)

3.5.2.1 Sewage Sludge

Industrial and municipal sewage treatment processes typically produce sludge which contains heavy metals, pathogens and volatile compounds. Disposing of sewage sludge is typically done in a number of ways including: landfilling, spreading onto agricultural land and incineration. Processing by removing pathogens, drying and grinding the sludge eases handling and increases combustion efficiency.

Table 18 provides a typical fuel analysis of pretreated sludge. The energy content of the fuel is only 12.94 MJ/kg on a dry basis, which is much lower than wood, which is typically 20 MJ/kg. The ash content is over 40%, which means that extensive ash management for this fuel would be required. To compound matters, the ash has very high levels of phosphorous, which can result in substantial agglomeration and fouling problems which would very quickly cause catastrophic failure of the fluidized bed. On this basis sewage sludge, even when dried, is not an acceptable fuel for this gasifier.

Table 17 Fuel analysis of treated sewage sludge

PROXIMATE ANALYSIS (WT%)		As Analyzed	Dry @ 105°C	Dry Ash Free
Moisture (ASTM D 5142)		4.86		
Ash (ASTM D 5142)		40.95	42.39	
Volatiles (ISO 562)		55.40	57.35	99.78
Fixed Carbon (by diff)		0.21	0.27	0.22
ULTIMATE ANALYSIS (WT%)				
Carbon (ASTM D 5373)		28.04	29.47	51.74
Hydrogen(ASTM D 5373)		3.87	4.07	7.14
Nitrogen(ASTM D 5373)		4.60	4.83	8.49
Sulphur (ASTM D 4239)		0.84	0.88	1.55
Oxygen (by Diff)		16.84	17.71	31.08
CALORIFIC ANALYSIS (ISO 1928)				
Cal/g		2941	3091	5427
MJ/Kg		12.31	12.94	22.72
BTU/LB		5294	5564	9769

Major and Minor Metals in Ash	
Test Name	**Sample 1**
SiO2	5.68 wt%
Al2O3	1.25 wt%
Fe2O3	46.60 wt%
TiO2	0.36 wt%
P2O5	16.36 wt%
CaO	9.65 wt%
MgO	1.56 wt%
SO3	4.84 wt%
Na2O	0.88 wt%
K2O	0.84 wt%
Barium	1592 ppm
Strontium	464 ppm
Vanadium	<50 ppm
Nickel	<50 ppm
Manganese	3434 ppm
Chromium	201 ppm
Copper	1609 ppm
Zinc	NR
Loss on Fusion	2.00 wt%
Sum	99.99 wt%

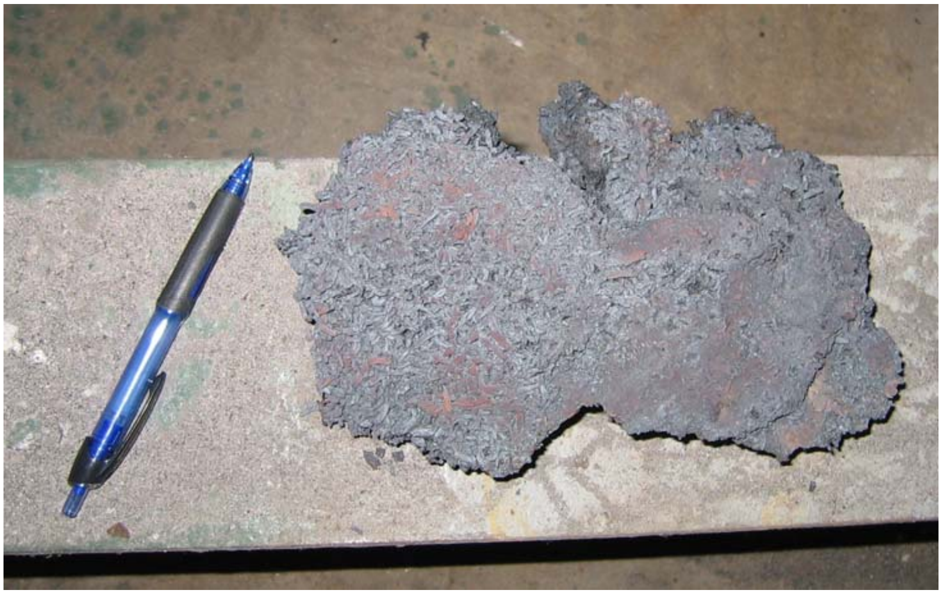

Figure 14 Clinker from the combustion of treated sewage sludge in a grate furnace

3.5.2.2 Municipal Solid Waste

According to Statistics Canada, over 30.4 million tonnes of waste was generated in Canada in 2002. This translates into 971 kg/person. Households accounted for 39% of this total, with the remainder generated in the industrial, commercial and institutional sector and the construction, renovation and demolition sector (Municipal Waste Integration, 2006). Table 19 provides an average composition of Municipal Solid Waste (MSW) in North America. This composition shows nearly 68% of the waste as biomass. Raven Recycling Company in Whitehorse is focused on removing many biomass streams from MSW. Therefore, an audit on the MSW in Whitehorse should be carried out and a representative fuel sample analyzed, if combustion is being seriously considered. If much of the biomass is removed, lower calorific values, and potential higher levels of chlorine from plastics could be a result. This fuel has difficulties with large variability in fuel properties, including but not limited to calorific value, moisture and chlorine content. An average fuel analysis of MSW is provided in Table 20. The calorific value of 14.3 MJ/kg is much lower than virgin wood, which is typically 20MJ/kg (dry basis).

Table 18 Design MSW Composition

Material	Percentage
Newspaper	10.1
Corrugated Cardboard	8.7
Other Paper	27.3
Plastics	8.1
Wood	4.44.8
Textiles	3.3
Rubber and Leather	1.5
Food Waste	7.2
Yard Waste	9.7
Glass	9.3
Ferrous Metal	5.2
Aluminum Cans	1.1
Other Aluminum	0.3
Non-Ferrous Metals	1.0
Sand, Stones, etc	2.4

(IEA,1999)

Table 19 RDF Ultimate Analysis (Design and Acceptable Range)

Constituent	Percent	Range
Carbon	33.85	25.06-38.37
Hydrogen	4.35	3.22-4.94
Sulphur	0.19	0.19-0.27
Oxygen	25.61	18.97-29.06
Moisture	21.1	15.00-35.00
Nitrogen	0.97	0.97-1.48
Ash	13.95	11.31-16.00
Higher Heating Value	6170 Btu/lb	4500-7000
	14.3 MJ/kg	10.4-16.2

(IEA, 1999)

Pre-treatment by sorting can be used to control the chemical components incorporated in potential waste derived fuels and pelletizing the waste allows for consistency in bulk density to facilitate storage, handling and feeding. Note that in Table 19, over 2% of the composition of MSW was sited as dirt, sand and rocks. These impurities have no calorific value, but will ware handling equipment and add to clinkers. Having an automated sorting process that is selective for size, removes metals and other recyclables is an ideal set up to achieve a fuel quality MSW. Figure 15 is a sample of MSW that was "hand sorted", however, impurities, metals and oversized materials made this an unacceptable fuel for the industrial grate furnace at CETC-O.

Figure 15 Municipal Solid Waste

3.5.3 Pellet-Based Feed System

A pellet-based feed system for the Yukon College gasifier system would be the simplest route that would ensure all of the fuel specifications would be met. The existing underground bunker and conveyors could be used with pellets. Since the size would not cause jamming of the feed system and the uniformity of fuel properties, such as, moisture and ash contents are guaranteed. Further, steady state operation of the gasifier will be more readily achieved. The current storage would be enough for a few days operation and additional silo storage could be incorporated on-site. This additional storage would not require a large amount of space and the pellets could be pneumatically conveyed from the above ground storage to the underground storage, or directly to the feed hopper. Onsite storage for wood pellets would be important, since the supply would be coming from outside of the Whitehorse area. This demand for wood pellets could foster the development of a pellet production facility within the Yukon.

Wood pellets have consistent fuel properties such as, low moisture (5%), high bulk density (>600 kg/m3) and high calorific value (>20MJ/kg on a dry basis).

For Yukon College a standard GSI 2440 ft^3 hopper tank would be an adequate storage volume. This would provide approximately 55 tonnes of additional on-site fuel storage. The moving and storing of wood pellets is similar to that of grain. The hopper tank will sit on a foundation and be equipped with a sealed roof, manhole, fill kit, ladder and cage. Figure 16 is a photo of a similar unit. A flex auger boot and 50ft of flex with a drive motor and switch will allow for the movement of pellets to the underground bin or to the existing feed hopper. The estimate for the storage installed is $26,290.

Figure 16 Bulk feed bin storage tank

3.5.4 Small Walking Floor Bin (50 tonnes)

This system would have 50 t of storage built into it, which is the smallest capacity of the three systems, but is adequate for approximately 4 days of wood chip storage at maximum burning rate. It comprises an enclosed bin with a Keith Walking Floor to automatically convey the wood chips to a screw auger at the end of the bin. The foot print of the bin is approximately 43’x 27’and 26’ high. This system is designed to receive wood chips from a walking floor tractor trailer, which can back into the bin to unload. From the screw, the feed would lead into a conveyor that would have a screener in line, to remove over sized particles and fines. All of these components would be exterior to the boiler house. A hole in the boiler house wall, in line with the feed hoper, would allow the conveyor to bring feed to the hopper.

Figure 17 shows a similar walking floor bin that is installed at Plum Creek. If the screw jams, the floor can back the pile away from the screw and the offending piece removed. The advantage of a Walking Floor bin is the screw is never buried very deep and the floor can be reversed. If there is a mechanical problem with the Floor drive (the cylinders), like a broken hydraulic hose, this equipment is all located under the Floor and accessible at any time.

Figure 18 shows the layout of the covered trailer feed bin and Figure 19 shows the layout at Yukon College. Low amounts of manual labour with regards to moving chips with a front end loader are expected with this system. The container, and covered conveyors should prevent any dust problems aside from a small disturbance during the unloading of trucks. Inspection of the fuel quality prior to the fuel entering the system will be difficult with this method.

Figure 17 Plum Creek - Keith Walking Floor Storage Bin

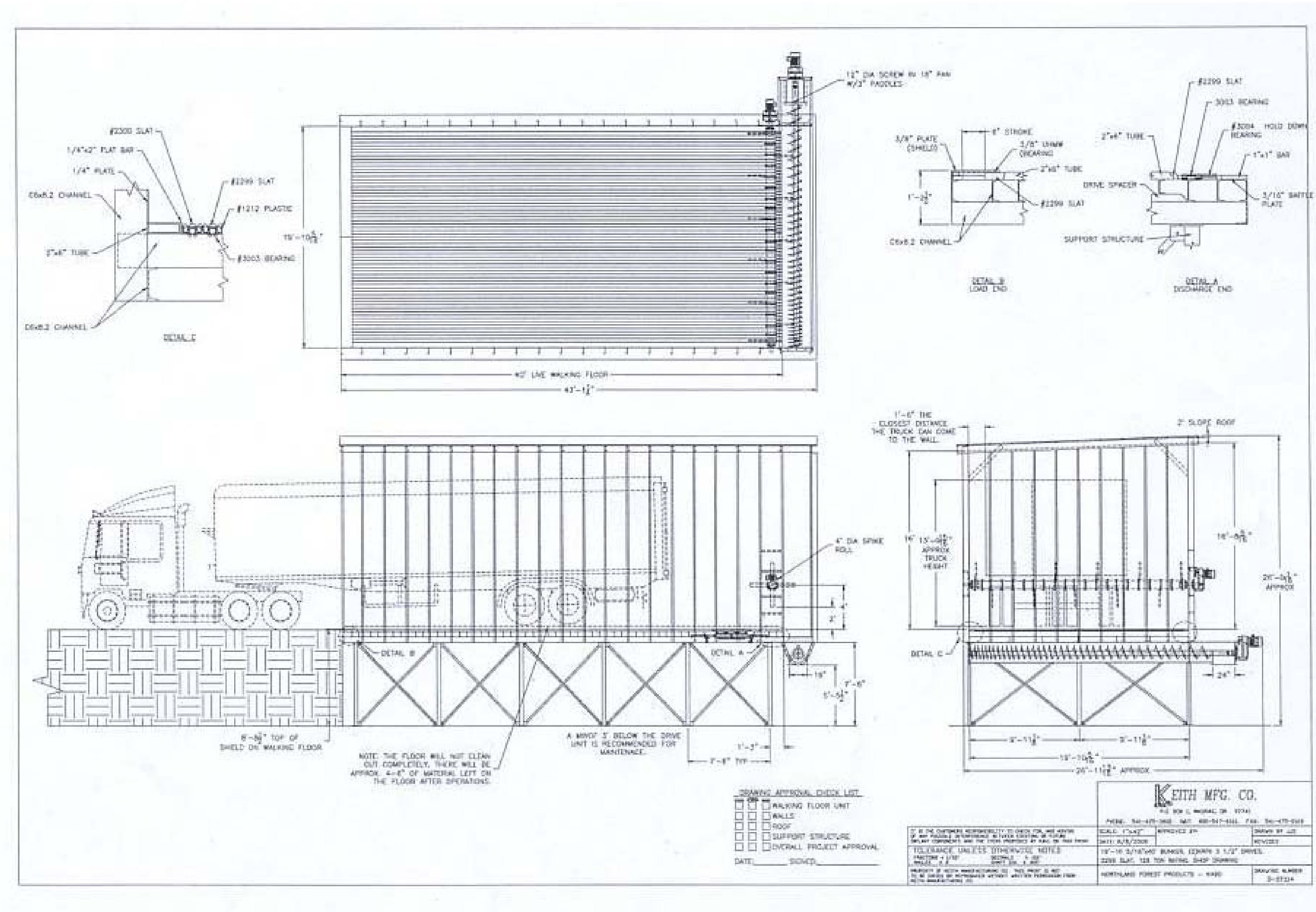

Figure 18 A drawing of a covered feed bin capable of 50 t of storage

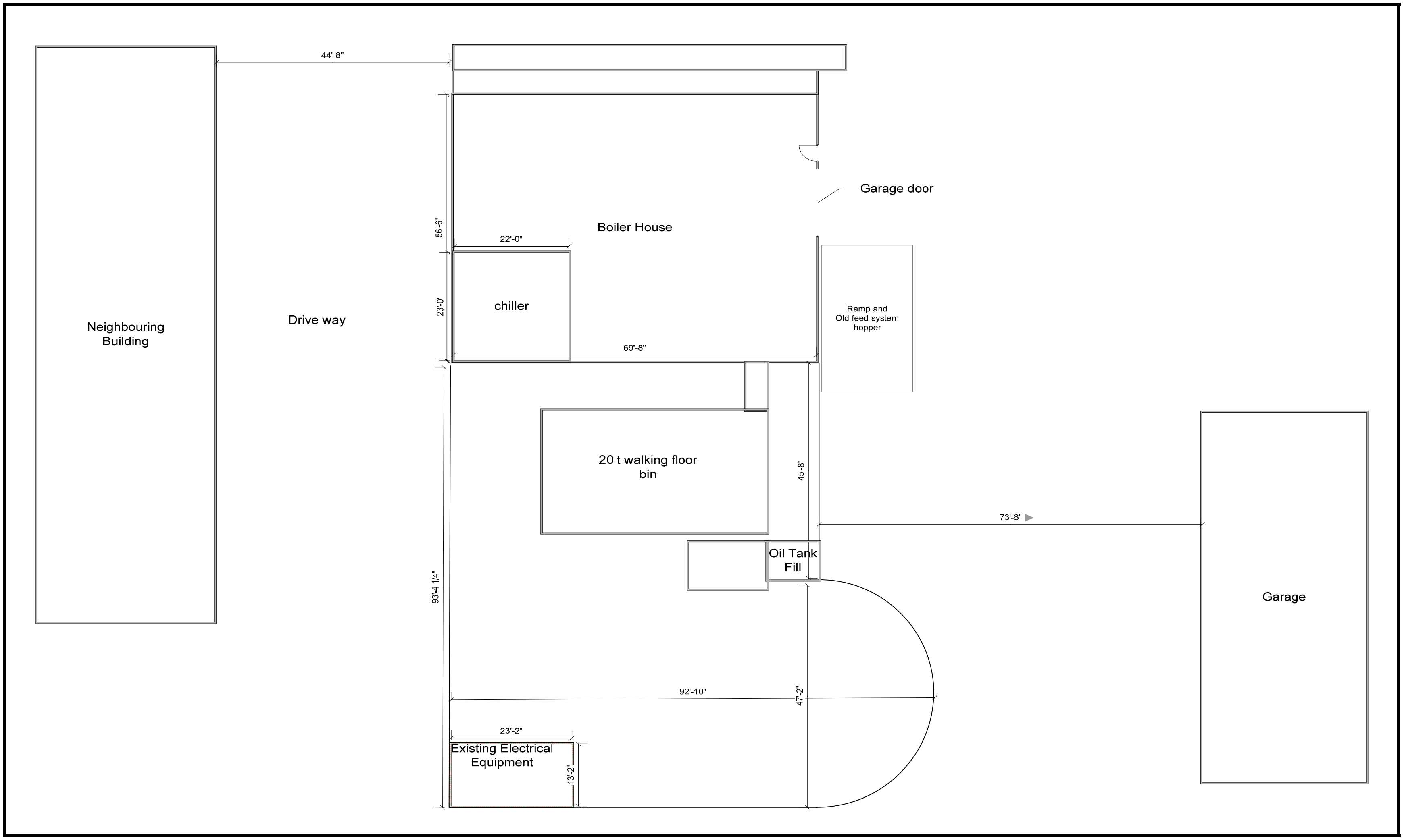

Figure 19 Site layout with the covered trailer feed bin system

3.5.5 Large Walking Floor Bin (200 tonnes)

This system is designed for 200t of storage and includes a separate receiving bin. The two are connected with a conveyor system that will be designed to unload a truck in 15 minutes. The bin has an approximate foot print of 74’x22’ and a height of 27’. The truck empties its load into a cement receiving bin 50’ long x 10’wide x 10’deep pile, which has augers that transport the fuel to three openings on the top of the feed bin. The bin is designed with levelling augers on the top of the bin, which moves the fuel within the bin to optimize the storage capacity. The bottom of the bin has a Keith Walking Floor that moves the fuel to a dual auger system that leads out of the bin and would connect with a conveyor that has a screener in line, to remove over sized particles and fines. All of these components would be exterior to the boiler house. A hole in the boiler house wall, in line with the feed hoper, would allow the conveyor to bring feed to the hopper.

Figure 20 shows a similar walking floor bin installation and the receiving bin would appear similar to the bin in Figure 17. There is an inspection hatch and access door on the storage bin. The access door is located at the discharge end of the bin near the screw. If the screw jams, the floor can back the pile away from the screw and the offending piece removed. The advantage of a Walking Floor bin is the screw is never buried very deep and the floor can be reversed. If there is a mechanical problem with the Floor drive (the cylinders), like a broken hydraulic hose, this equipment is all located under the Floor and accessible at any time.

Figure 21 shows the layout of the conveyor fed bin and Figure 22 shows the layout at Yukon College. Some manual labour with regards to moving chips with a front end loader is expected with this system. The container, and covered conveyors should prevent any dust problems aside from disturbances during the unloading of trucks. Fuel inspection while the load is in the receiving bin is possible.

Figure 20 Keith Walking Floor System

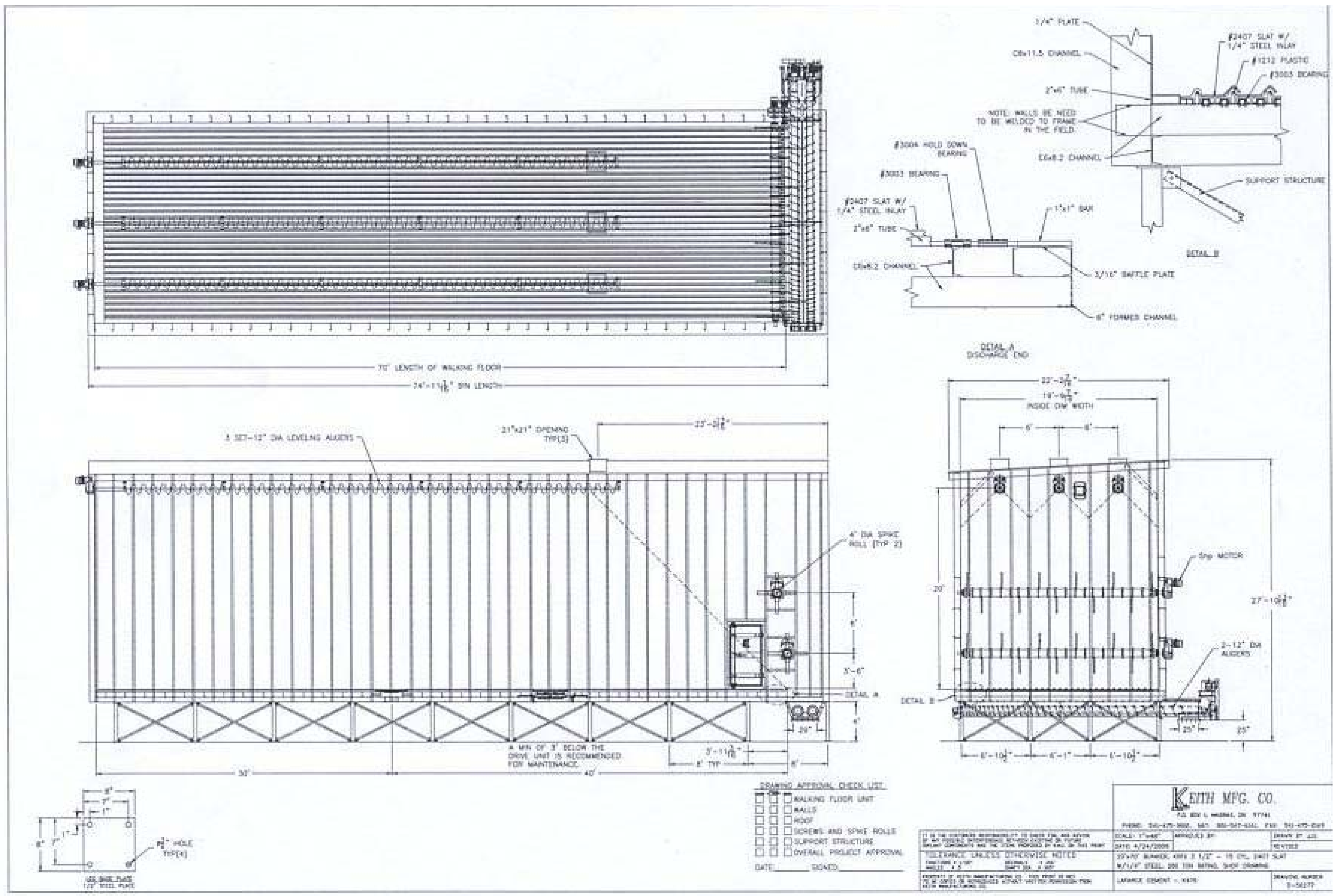

Figure 21 Drawing of the conveyor fed system

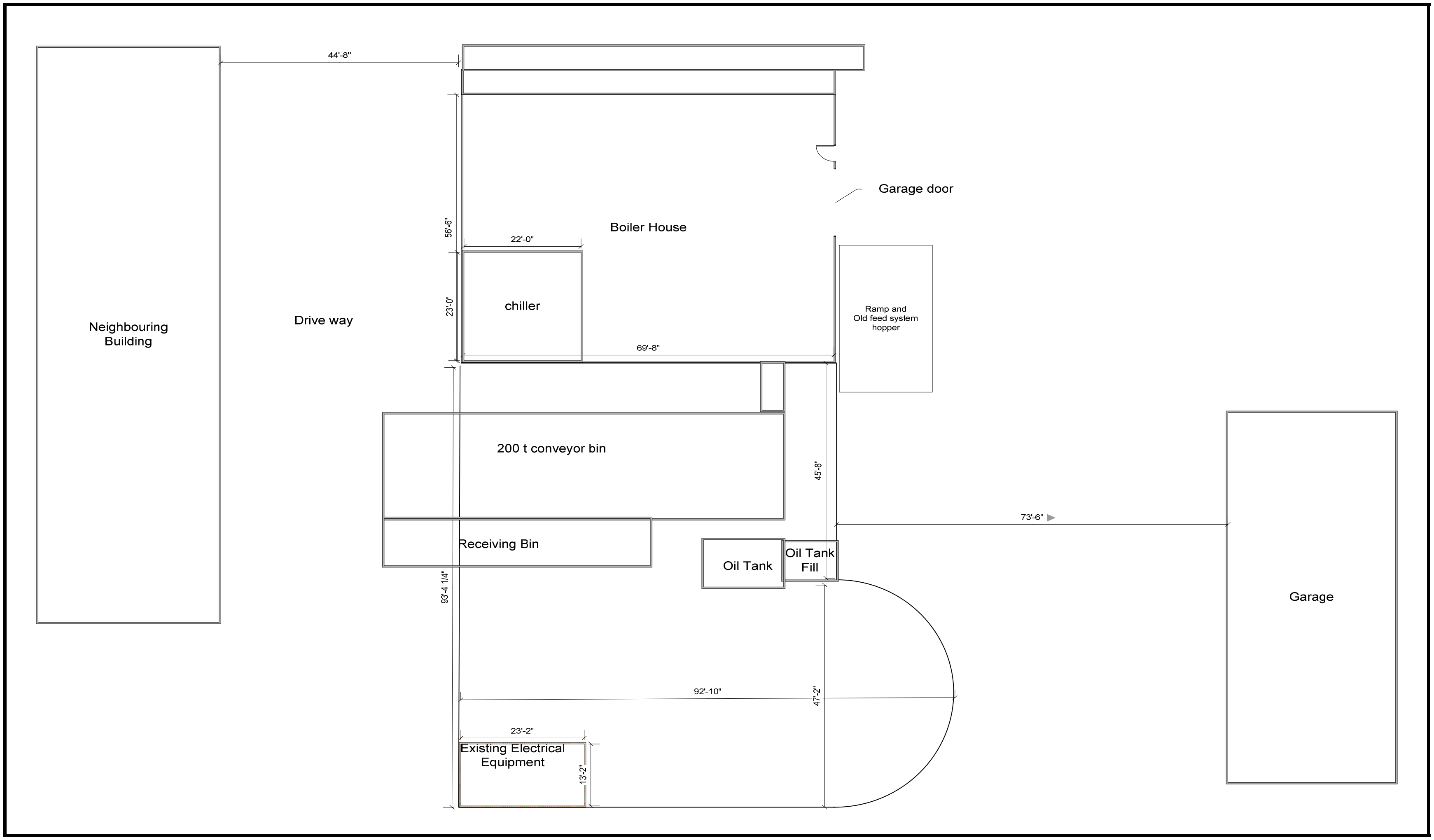

Figure 22 Site layout with conveyor fed bin system

3.5.6 Dual Fuel Auger System (120 tonnes)

This system was designed to have 120 t of storage and the ability to utilize two fuels. This redundancy also allows for maintenance to be done to part of the system while firing the fluidized bed. The foot print for the system is 77' x 39', with a variable height depending on the type of delivery truck used. If there is a problem with receiving high quality or low moisture fuels, this system can mix a high and low quality fuel so that the gasifier utilizes an average fuel. The two bays are equipped with screw augers that move the fuel to a conveyor. The twin conveyors dump into a main conveyor with a screener in line, to remove over sized particles and fines. All of these components would be exterior to the boiler house. A hole in the boiler house wall, in line with the feed hoper, would allow the conveyor to bring feed to the hopper.

Figure 23 illustrates a similar style of feed system that exists at a greenhouse in Ontario. Figure 24 shows the layout of the conveyor feed bin and Figure 25 shows where it would fit with respect to the existing infrastructure. If this facility is designed to be high enough for trucks to back in and dump fuel, a decreased amount of manual labour will be required. Alternatively, if the fuel is delivered with a walking floor truck, which would also decrease the manual labour required upon fuel delivery. The layout of the system allows for easy access to all of the conveyors and access around the wood piles for fuel inspection. This asset will ease maintenance and allow for quicker identification of problems and troubleshooting.

Figure 23 Biomass feed system showing a bay of fuel being moved by a screw auger

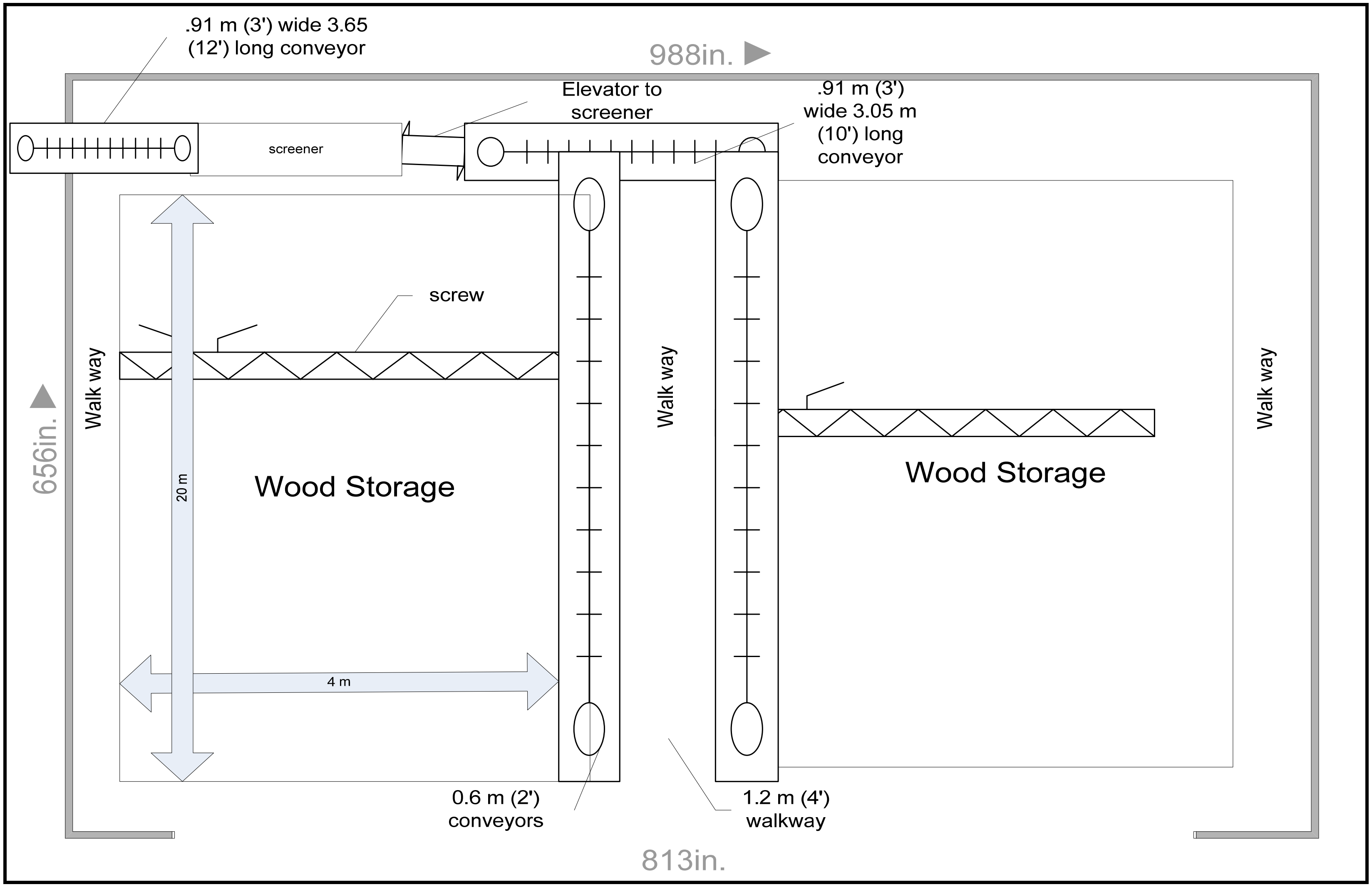

Figure 24 Dual feed system layout

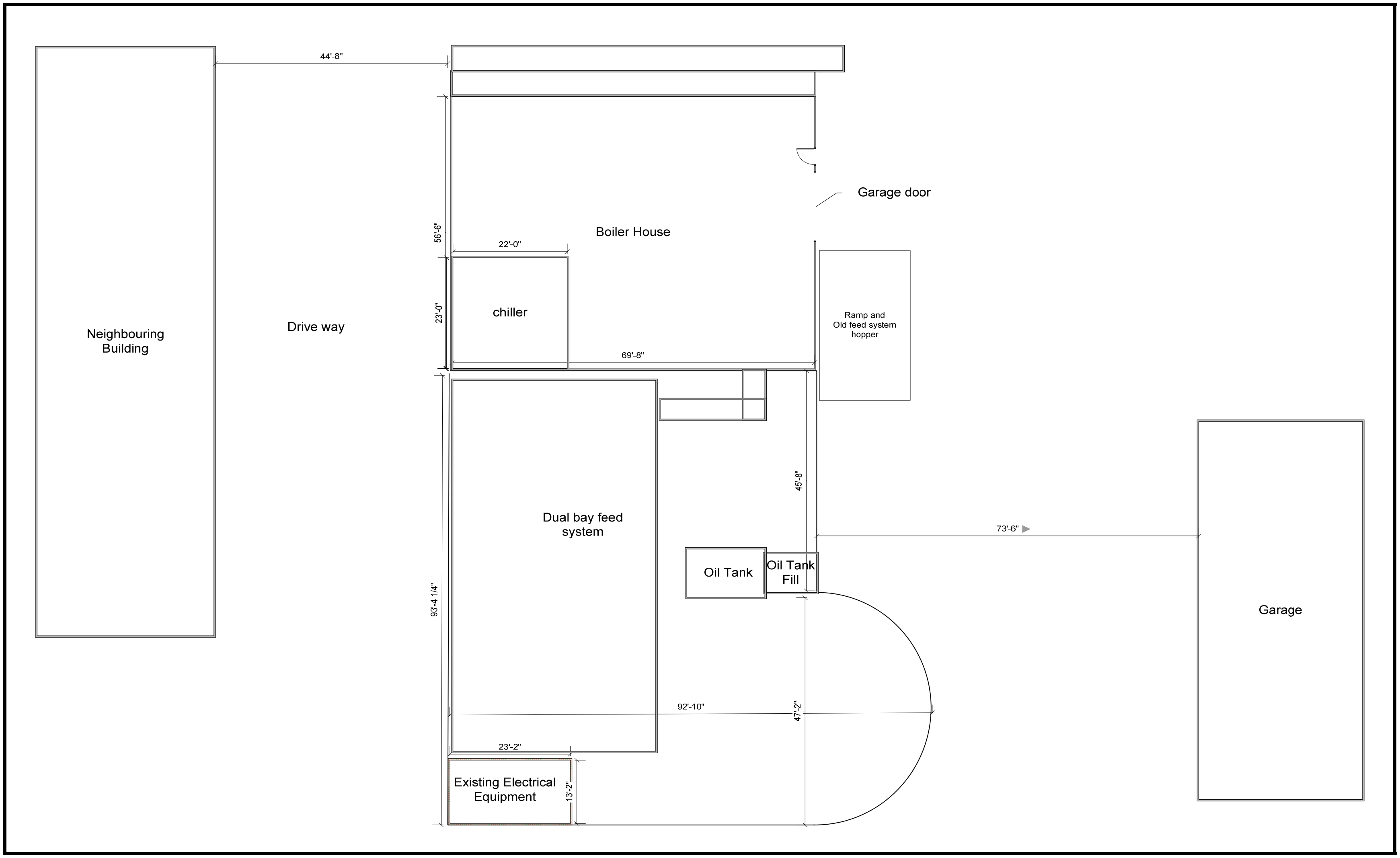

Figure 25 Site layout with covered dual feed system

Fuel System Enclosure

Of the four fuel systems described above: pellet-based, small walking floor bin, large walking floor bin and dual fuel auger system, only the last requires special consideration for the enclosure. The other options come with designed bins. As mentioned in the dual fuel auger system discussion, the height of the building is dependent upon how the fuel is delivered. If the wood chips are received using a walking floor truck, the building height could be approximately 20'. In this case, steel hoop buildings are an option, as well as, other similar structures. However, if there is the need to have delivery by trucks that dump their loads using a full tractor trailer, a much higher building is required. In this case, a more defined structure is needed, or a cement wall built under a hoop style building.

The Fold-A-Way® metal building is movable, easy to setup, and can be reconfigured in an almost endless variety of designs. Fold-A-Way® buildings have been used for such diverse projects as maintenance shops, warehouses, first aid shelters, equipment storage and other applications. ATCO Structures provided an estimate for a 40' x 80' foot print with a height of 25' and two end walls with sliding doors $234,057 (taxes not included). An estimate for transportation and installation was suggested at $50,000. This structure has a total cost estimate of $284,057.

3.6 Fuel System Cost Estimate Summary

The four feed systems discussed in the previous section are broken down by component and associated costs to provide an estimated cost for each system, see Table 21. The highest cost of $718,647 is associated with the conveyor fed bin, which has the largest storage capacity. The most economical system is the pellet storage costing $46,616. The most economical wood chip system was $278, 647 with 50t of storage. The covered dual feed system is $483,000 with the most expensive component being the building, which covers the system. If this style of feed system is desired, potential alternatives could be sought to decrease the cost of the system. The B303HSDC Kubota tractor has been included with all of the wood chip estimates to provide the operators with a means to efficiently handle material. Depending on the amount of material handling, the college may have this capability using existing equipment.

Table 20 Fuel Systems Cost Estimates

Pellet-Based Feed System		
Storage bin (55t)		$ 26,290
cement pad		$ 20,000
Hole in the wall	2 workers for 2 hrs	$326
Total		**$ 46,616**
Small Walking Floor Bin		
Covered trailer fed bin	50 t of storage, covered	$ 200,000
fuel screener	BM&M	$ 4,824
cement pad		$ 20,000
Conveying system	Elevator, screener, conveyors, stairs, cover for screener, pad for screener	$ 20,000
B3030HSDC Kubota Tractor	tractor w heated cb, forks and bucket	$ 33,497
Hole in the wall	2 workers for 2 hrs	$ 326
Total		**$ 278,647**
Large Walking Floor Bin		
receiving bin	verbal estimate based on slightly larger units	$ 200,000
200t storage bin & controls		$ 370,000
conveyors		$ 50,000
fuel screener	BM&M	$ 4,824
cement pad		$ 40,000
Conveying system	Elevator, screener, conveyors, stairs, cover for screener, pad for screener	$ 20,000
B3030HSDC Kubota Tractor	tractor w heated cb, forks and bucket	$ 33,497
Hole in the wall	2 workers for 2 hrs	$ 326
Total		**$ 718,647**
Dual Fuel Auger System		
conveyors, screws and drives	based on a similar system in a greenhouse installation	$ 120,000
Stairs over conveyor to hopper		$300
cement pad	2 bays with total of ~120 t of storage	$ 40,000
support and cover		$ 284,057
fuel screener	BM&M	$ 4,824
B3030HSDC Kubota Tractor	tractor w heated cab, forks and bucket	$ 33,497
Hole in the wall	2 workers for 2 hrs	$326
Total		**$ 483,004**

3.7 Completely New Biomass-Based Furnace Systems

Grate Furnace System

As an alternative to refurbishing the fluidized bed gasifier at Yukon College, a quotation for a brand new grate furnace system has been included to provide a comparison. A grate furnace is a different type of technology that is popular in the pulp and paper industry. These types of combustion systems are commercially available. A schematic is provided in Figure 26. The biomass is fed into the combustion chamber where under-fire and over-fire air is introduced to complete the combustion. The hot flue gases are put through a boiler (heat exchanger) and then exit to emissions controls and a stack.

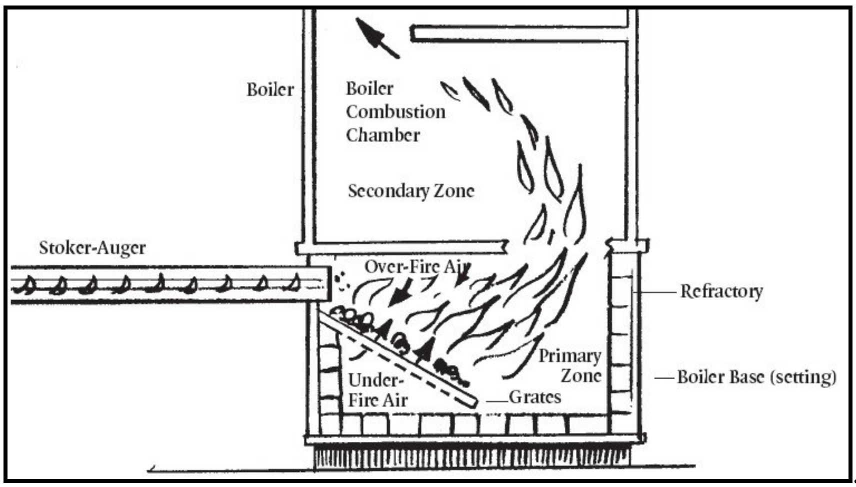

Figure 26 Grate furnace schematic

A 4.5 MWth Vyncke water-cooled step grate furnace has been quoted to provide a comparision to the refurbished fluidized bed system. The quote includes the fuel feed system, 4.5MWth combustor, automatic wet-ash removal, dust collector, ESP, hot water storage tank and a chimney stack. The equipment details can be located in Appendix D. The pricing is shown in Table 22 with a grand total of $1,975,987, please note the list of components that are not included in the quote. The layout of the feed system and combustor is shown in Figure 27, which has a total area requirement of 9,450 ft^2.

Table 21 Grate Furnace System Cost Estimates

Equipment	Cost
4.5 MWth grate furnace	$ 891,675
Thermo Energy Systems	$ 505,000
Silo unloading system with moving floor	
Chain conveyor for fuel transport	
Chain conveyor for wet ash evacuation	
Dust Collector	
Automatic fly ash evacuation system	
Flue gas ducting without insulation	
Chimney	
Hot Water Storage Tank (757,082 L)	$ 282,312
Electrostatic Precipitator	$ 297,000
Total	**$1,975,987**

Excluded in Thermo Energy Systems quotation

- concrete and foundation work
- Rotary air lock valves for fly ash
- all electrical wiring (low and high voltage)
- all permitting for project
- transportation of equipment
- Utilities to supply or connect equipment supplied by Thermo Energy Systems Inc. and Vyncke
- Hydraulic fluids,fittings, and pipe
- All applicable taxes
- Ash bin
- Crane and other equipment rentals for unloading and erecting
- Pumps and heating connections to tank, Vyncke boiler to existing heating system including changes required to the existing heating system.
- Chimney size is an estimate only, to be determined by EPA permitting
- All type of emission filtering equipment

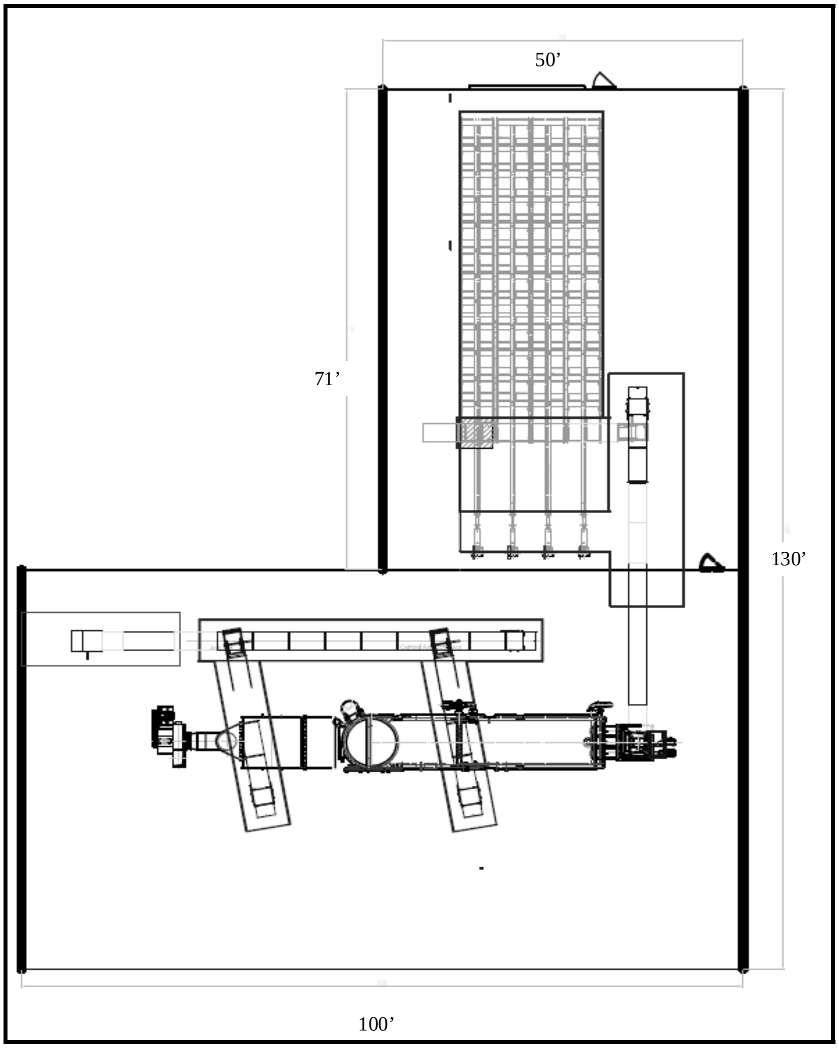

Figure 27 Vyncke System Layout

New Pellet-Based Heating System

CETC-O staff carried out a review of available technologies and decided that a modular approach would be best suited for the Yukon College in order to take advantage of the existing space and allow for load changes and also some redundancy. It would be possible to install a wood chip boiler such as considered under Alternate Option 1 and burn pellets in the unit. However, given the substantial capital cost for wood chip handling equipment and the high cost of pellets this would be a very expensive mode of operation. CETC-O indentified a suitable system for burning pellets – KOB Pyrtec KPT-1250 with a rated heat output of 1250 kW. This is a German-made unit which could be supplied in Whitehorse by Fink Machine Inc, of Enderby BC. The installed cost of one KPT-1250 excluding pellet storage and feed system is estimated at $360,000. Pellet fuel storage costs would be as noted above for gasifier re-capitalization or approximately $66,000. In order to replace the gasifier a minimum of two KPT-1250 furnaces would be required thereby bringing the cost of the units to provide 2500 kW to $786,000. In terms of space requirements, the furnace footprint is 5.6 m x 2.2 m which translated into a 40 ft by 20 ft space to accommodate two units. These would fit within a “vacated” boiler house which has dimensions of 47 ft by 56 ft. The price for the KPT-1250 units does not include emissions control equipment.

4 Research Potential

Aside from the environmental and economic benefits of operating the gasifier to provide heat from a renewable resource, the gasifier installation itself offers the opportunity to serve as the basis of future economic and technical developments. In its simplest form, the syngas produced by the gasifier is composed of two diatomic molecules, CO and H_2 that aside from being useful as gaseous fuels, provide the building blocks upon which an entire field of liquid fuel synthesis is based. An operating gasifier could be integrated into research activities at Yukon College and provide pathways to investigations into advanced power generation technologies, production of liquid fuels (bio-diesel, ethanol and methanol) and as an entry point to the hydrogen economy.

4.1 Syngas Extraction and Clean-up

The raw syngas exiting a biomass gasifier contains particulates, tars, and other constituents that may interfere with downstream utilization technologies. The concentrations of these constituents will depend on the reactor design and other factors as explained previously. Regardless of the scale of the gasifier, its design configuration, or the biomass feedstock, the characteristics of the syngas must match the requirements of the intended use. For some applications such as kilns or co-firing systems, the raw fuel gas may be used with little or no cleanup. In other applications, such as gas turbines or internal combustion engines, extensive gas cleanup may be needed to meet stringent fuel quality requirements. If the gas is to be used for synthesis of liquid fuels, the product must not only be clean, but must also have specified molecular ratios of components, such as, H_2 or CO. In all cases, care must be exercised to ensure the syngas is compatible with the end-use. Biomass Integrated Gasification Combined Cycle (BIGCC) based systems have stringent requirements regarding gas quality.

Systems producing either fuel or synthesis gas must deal with the cleanup of five primary contaminants:

- particulates
- alkali compounds
- tars
- nitrogen-based components
- sulphur

4.1.1 Particulates

Particulates are defined as solid-phase materials entrained in the raw syngas stream as it exits the gasifier. Particulates typically include ash, unconverted biomass in the form of char and inert material from the gasifier bed. Most large-scale gasifiers use bubbling or circulating fluidized configurations to ensure uniform bed conditions during gasification. The turbulent conditions in these gasifiers produce high particulate loadings in the syngas. As a result, particulate cleanup is necessary with these systems and most include cyclones to separate the bed material from the syngas. The cyclone serves as the initial particulate removal technology and removes the bulk of coarse particulates, but finer fly ash will remain in the gas stream. The resulting fly ash consists of smaller-diameter material that can create operational and visual emissions problems if they are not removed. Mineral matter can abrade and damage downstream equipment, and most emission regulations limit the amount of fly ash that can be present. Systems to control particulates will be needed in essentially all large-scale biomass gasification systems. Particulate removal requirements vary significantly depending on the use of the syngas. For example, particulate levels must be reduced to below 50 mg/Nm^3 for gas engines (Abatzoglou et al., 2000) and to below about 15 mg/Nm^3 (>5μm) for turbines. The primary types of systems for particulate cleanup are cyclones, fabric filters, electrostatic precipitators and wet scrubbers.

4.1.2 Alkali Compounds

In addition to the quantities of mineral matter present, the composition of the mineral matter must also be considered. The chemical composition of the ash determines the physical properties, such as, softening, melting, or vaporization temperatures. Biomass feedstocks may contain significant amounts of alkali salts, particularly potassium. The high alkali content of some biomass feedstocks can create significant gas cleanup challenges. Eutectic sodium and potassium salts in the ash material can vaporize at moderate temperatures of about 700°C. Unlike the solid particulates that can be separated by physical means, the vaporized alkali compounds will remain in the syngas at high temperatures. Condensation of the vaporized alkali typically begins at about 650°C on particles in the gas stream, with subsequent deposition on cooler surfaces in the system such as heat exchangers. The problem of alkali deposition in biomass fueled turbine systems was particularly evident in research during the 1980s that used a direct combustion gas turbine system (Hamrick, 1991). Although particulate loadings at the turbine inlet met manufacturers specifications, a glassy ash material rapidly deposited on the blades of the expansion turbine at inlet temperatures above about 785°C. The problem arose from alkali vapours that passed through gas cleanup systems and deposited as the gases cooled during expansion. Miles and co-workers (1995) have reported on improved understanding of the alkali vaporization and subsequent ash deposition phenomena. Gas turbine limits for alkali are about 20 ppb.

In current gasification systems, alkali vapours are removed by cooling the syngas to below 600 °C to allow for condensation of the material into solid particulates. The solids are then removed using filtration systems as described above. In systems that are sensitive to deposition of alkali salts, filtration systems must account for the small particle size and the chemical behaviour of the condensed material. Cyclones, for example, will be ineffective at removing the <5 μm solids. This approach, while effective, requires cooling of the syngas and the accompanying loss of sensible heat, which reduces system efficiency. Recent research has shown that alkali "getters"(activated bauxite, emalthite or hectorite) may be effective in removing alkali from the gas stream at high temperature (Turn et al., 2001). "Getter" beds can be designed as parallel fixed beds, giving continuous operation while allowing for bed material replacement. While this approach has not yet been tried in large-scale systems, the results suggest that it may be an effective way to remove alkali while preserving the heat content of the product.

4.1.3 Tars

In biomass gasification terms, tar is a complex range of oxygenated organic constituents that are produced by the partial reaction of the biomass feedstock. Such materials reside in the hot gas stream as vaporized material or as persistent aerosols, but typically condense at cooler temperatures. The composition of tar is complex and highly dependent on the severity of reaction conditions encountered, including gasification temperature and residence time in the reactor. Tars in the syngas can be tolerated in some systems where the gas is used as a fuel in closely coupled applications such as co-firing (e.g. Lahti). In these situations, cooling and condensation of the tars can be avoided, and the energy content of the tars adds to the calorific value of the fuel. In more demanding applications, however, tars in syngas, even at low concentrations, can create major handling and disposal problems. Tars readily condense on cool components downstream from the gasifier, resulting in plugging and fouling of pipes, tubes, and other equipment. In temperature regions above about 400°C, the tars can undergo subsequent dehydration reactions to form solid char particles that further plugs systems. The tars can represent a cleanup problem and may be classified as hazardous wastes for disposal purposes. In a gasifier-based system tar disposal can be avoided by re-injecting the collected tars into the gasifier. Since the tars are essentially long-chain organic molecules, they will break up (i.e gasify) if properly introduced in to the dense bed of the gasifier.

Two basic approaches have been used to remove tars from syngas streams. Most commonly, condensed tar droplets are physically removed using technologies similar to those used for particulate removal. These require that the syngas be cooled to ensure the tars are in a condensed form.

Catalytic tar crackers operate at temperatures comparable to the gasifier, ~825°C while thermal crackers typically operate at higher temperatures (880-1000°C). Typically, after tar cracking, the syngas is partially cooled to minimize the amount of alkali vapours (500 - 600°C). The product is then passed through a ceramic filter to remove solids. Much of the alkali is also removed. Alternatively, the gasifier can be operated at low pressure and the cleaned syngas compressed to the pressure required for gas-turbine application. In this case a tar cracker would be used to minimize the amount of tar that must be handled during quenching. Standard practice is to use a combination of heat exchange to bring the gas to the residual tar dew point followed by wet scrubbing.

Wet scrubbers collect tars through the impingement of the material on water droplets. The tar and liquid flow to a demister or decanter and the bulk tars are separated from the aqueous phase. The use of water in these scrubbers means that the syngas temperature at the exit is in the range of 35 to 60°C. Research using oils as scrubber fluids in biomass systems has also been performed but these designs have not gone past the experimental stage of development (Bridgwater, 1995). A wide variety of scrubber designs are available including: spray towers, impingement scrubbers, baffle scrubbers, and Venturi scrubbers. Wet scrubbers have been used extensively in the gas processing industry, and their performance is well characterized in those applications. Wet scrubbers have also been used in numerous biomass gasification systems, but the actual operational performance of these scrubbers is less than perfect. Electrostatic precipitators are very efficient at removing either tars or particulates from the gas stream, and can remove up to 99% of materials under 0.1 µm in diameter. This technology is mature and available commercially for a variety of applications. The use of these systems with large-scale biomass gasifiers, however, is not promising due to high capital and operating costs.

4.1.4 Nitrogen-based Compounds

The primary nitrogen related contaminant in the raw gas from biomass gasifiers is ammonia formed from the nitrogen in the biomass. Ammonia in the product stream is undesirable primarily because it leads to the formation of NOx emissions when the syngas is burned. Cleanup of the ammonia is therefore required in locations with strict NOx regulations. NOx is also produced in some gasifiers, but is generally not present in high enough concentrations to create problems. The combustion of syngas rather than solid biomass provides the means for improved control, which can result in lower NOx emissions. For this reason, gasification offers potential environmental emissions advantages over combustion alternatives.

4.1.5 Sulphur

Sulphur in the biomass feedstock can be converted to hydrogen sulphide or sulphur oxides during gasification, depending on the gasification approach. Wood typically contains less than 0.1% sulphur by weight, and herbaceous crops may contain 0.3-0.4% (Klass, 1998). A few feedstocks such as refuse-derived fuel (RDF) may contain 1% or more, approximately the same as bituminous coal. As a result of the low levels of sulphur in the biomass, the concentrations of H_2S and SOx levels in syngas are below those requiring cleanup in most applications. Sulphur, however, is a potential problem even at low levels for using certain types of catalysts. The production of methanol from synthesis gas, for example, uses catalysts that are poisoned by sulphur. Some tar cracking catalysts are also sulphur sensitive. In those systems, thorough removal of sulphur will be required.

4.2 Combined Heat and Power

Biomass fuels exist in many areas that lack conventional infrastructure, e.g. an electrical supply grid. Many of these sites must use imported fuel oil to generate small-scale power at substantial cost. There is therefore considerable interest in using the local biomass resource (in many cases a residue stream) to generate power. The size of these would typically be in the 250 kWe to 5 MWe range. This is a size range in which the conventional Rankine steam cycle, although technically feasible, is not economically feasible due principally to the need for continuous manned attendance. Efforts underway within the last five years have been aimed at developing "small modular" automated, safe and reliable biomass-fired systems, which can meet these needs. There are as yet no systems that can approach these criteria. Typical costs for existing systems are in the $4,000-$5,000/kWe range. The consensus is that the current price barrier for these systems is about $3,000/kWe.

Small gasifiers coupled to diesel or gasoline engines (typically for systems of 100-500 kilowatts of electricity with an approximate electrical efficiency of 15-25 percent) are being pursued by a large number of companies worldwide. The basic principle of power generation is illustrated in Figure 28. The limiting factors to date have been high costs and the need for gas cleaning and unmanned control systems. Some crude systems are being applied fairly successfully in rural India and in China and Indonesia. For example, in China at least 20 fluidized bed gasifier/internal combustion engine plants are operating but the engines require shutdown and overhaul every 100 hours due to the contaminants in the syngas. In Europe a few units are operating with some success but they depend on very expensive multi-stage gas cleaning. Gas cleaning and conditioning remains a key requirement for these systems and a facility such as the Yukon College Gasifier would provide a good platform for such research. The heating value of gases that can be turned into electricity at an efficiency of up to 40% lies between 0.5 kWh/m^3 and 34 kWh/m^3, which is well within the range which could be produced by the Yukon College Gasifier. Jenbacher systems apply combustion technologies that have been patented worldwide and achieve guaranteed emission levels below 250 mg/m^3 of NOx and below 300 mg/m^3 of CO when operated with natural gas. The overall energy efficiency of the systems is as high as 88% when operated in cogeneration mode - i.e. simultaneous production of heat and power. For example, the Yukon College Gasifier could produce syngas which after cleaning is used to run an internal combustion engine. The hot exhaust from the engine could then be run through a boiler thus generating hot water to provide space heating. Such a project at Yukon College would be the first in Canada and certainly a showcase for advanced energy from biomass.

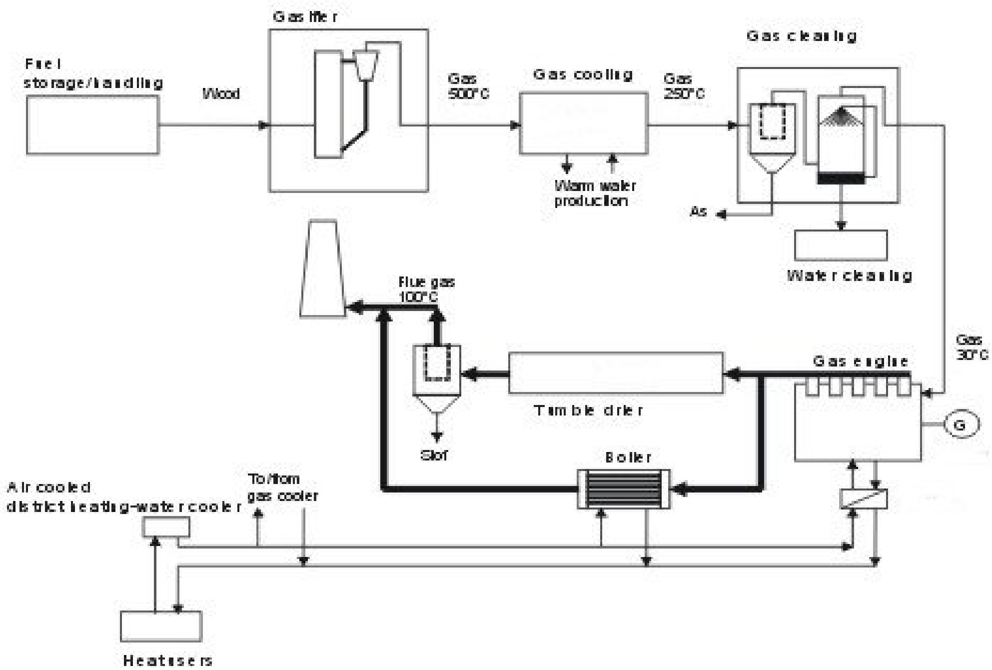

Figure 28 Combined Heat and Power Schematic

4.3 Liquid Bio-fuels Research

The synthesis of hydrocarbons from CO hydrogenation has been studied since the early 1900's, when researchers first produced methane by passing CO and H_2 over Ni, Fe, and Co catalysts. Many of the syngas conversion processes were developed in Germany during the First and Second World Wars at a time when natural resources were becoming scarce and alternative routes for hydrogen production, ammonia synthesis, and transportation fuels were a necessity. With the development of the petroleum industry in the 1940s and beyond, the unattractive economics of many of these syngas routes became an issue and were replaced by petroleum-based processes. Increasing environmental concerns and tighter regulations surrounding fossil fuel have provided the impetus for syngas conversion technologies to produce cleaner (virtually no sulphur) fuels and chemicals. The latest environmental driver to likely increase demand for syngas even more is the goal of establishing a hydrogen economy. The vision is that hydrogen will be the fuel of choice for transportation and electricity generation via high efficiency, environmentally benign fuel cells.

Through gasification, biomass can be converted into a large number of organic compounds that are useful as chemical feedstocks, fuels and solvents. At the center of this transformation is the use of selective catalysts (under heat and pressure) to convert the carbon monoxide and hydrogen into larger, more useful compounds. Much of the research which has gone into these processes has in the past been based on coal gasification. Biomass gasification brings with it a whole new set of technical problems that have to be resolved, principally in cleaning and conditioning the syngas. Raw biomass syngas has tars and contaminants which not only reduce the viability of the conversion processes but can actually act as poisons to the various catalysts. Raw syngas from the gasifier needs to first have contaminants removed that would inactivate the catalyst. This includes sulphur compounds (e.g. H_2S, mercaptans), nitrogen compounds (e.g. NH_3, HCN), halides (e.g. HCl), and heavy organic compounds that are known collectively as "tar".

A facility, such as the Yukon College Gasifier, could provide a syngas stream to be used by researchers to study advanced gas cleaning, conditioning and conversion. These activities would not interfere with the use of the gasifier as a heat source for the campus but would be based on drawing off a small "slip stream" of gas prior to B1 boiler. This type of activity is common at many European universities where the heating plant is incorporated into advanced energy research. The operation of the equipment by heating plant staff serves as an enormous benefit to researchers by removing the requirement to have research staff operating large combustors and gasifiers.

The process of converting CO and H_2 mixtures to liquid hydrocarbons over a transition metal catalyst has become known as the Fischer-Tropsch (FT) synthesis. The first FT plants began operation in Germany in 1938 but closed down after the Second World War. Common problems of Fisher-Tropsch synthesis (FTS) are low product, unavoidable production of olefins, paraffins, and oxygenated products) and the sensitivity of the catalyst to contamination in the syngas that "poison" or inactivate the catalyst. Research to improve both the selectivity of catalysts to make purer, high value products and better resistance to "poisons" both contribute to lowering the cost of production.

A second, important, conversion processes for syngas is to methanol. Methanol is a commodity chemical, one of the top ten chemicals produced globally and is an important chemical intermediate used to produce a number of chemicals, including: formaldehyde, dimethyl ether, methyl tert-butyl ether, acetic acid, and olefins, to name a few. Methanol can also be used directly or blended with other petroleum products as a clean burning transportation fuel. Higher alcohols or methanol mixed with higher alcohols would be better than straight methanol as a gasoline additive to boost octane, avoiding certain drawbacks of straight methanol. Modified catalysts for these processes are among the more seriously pursued processes for producing higher alcohols from synthesis gas. No commercial production exists at the current time.

Anaerobic bacteria can also be used to convert syngas into ethanol. In the US, Bioresource Engineering Inc. has developed synthesis gas fermentation technology that can be used to produce ethanol from biomass wastes. After gasification, anaerobic bacteria such as Clostridium ljungdahlii are used to convert the CO, CO_2, and H_2 into ethanol. The process of combined gasification/fermentation has been under development for several years and is currently at the pilot plant stage.

4.4 Research for the Hydrogen Economy

Biomass has the potential to accelerate the realization of hydrogen as a major fuel of the future. However, hydrogen from biomass has major challenges. There are no completed technology demonstrations. The key to hydrogen utilization is fuel cell applications and so product purity requirements for the fuel cell will drive the gas purity requirements of all production systems. In gasification, the presence of hydrocarbons and trace levels of nitrogen, sulphur, and chlorine compounds must be addressed, not only for end use applications, but also for shift reaction catalysts and separation systems, such as pressure swing adsorption (PSA). The basic steps in the production of hydrogen from biomass are as follows:

i. Biomass gasification
ii. Gas clean-up
iii. Catalytic Steam Reforming
iv. Water Gas Shift Reaction
v. Gas Separation (PSA)

The water-gas shift reaction is the mechanism used to convert carbon monoxide to carbon dioxide and hydrogen through the following reaction with water:

$$CO + H2O <> CO2 + H2$$

This reaction is exothermic, which means that the reaction equilibrium shifts to the right and favours the formation of hydrogen at lower temperatures. At higher temperatures the equilibrium shifts to the left which limits the conversion of to hydrogen. The concentration of hydrogen in the syngas can be enhanced by introduction of steam to the gasifier. For purposes of research, this could be accomplished by addition of a small electric steam generator in the vicinity of the gasifier. The additional installed cost of this component would be under $25,000 and could be easily integrated into a bio-fuels research program.

Most of the steps involved in the conversion of biomass to hydrogen are understood. The one requiring the most development is the gas clean-up and, as has been noted throughout this section, the Yukon College Gasifier would be an excellent platform on which to build a research program for the development of bio-fuels including hydrogen.

4.5 Preliminary CHP Cost Estimates

The principal components of the combined heat and power installation would be for syngas clean-up, an engine/generator set and electrical connection panel. The first stage of syngas clean-up has already been discussed in the section on emissions control and would consist of a scrubber and heat exchanger and was estimated to cost $120,000. The second component would be a filter/de-mister which would have to be custom-built and an initial estimate is $60,000. At this point the syngas should be clean enough for a relatively robust engine such as a Kohler 500 kWe engine shown in Figure 28 (Model: 500REOZVB , 277/488v (reconfigurable), designed for diesel but adaptable for syngas).

Figure 29 Kohler Engine

The installed cost of this engine in a weatherproof enclosure is $110,000. Electrical connection panel has been estimated at $25,000. Plumbing the heat extraction system into the engine and other minor requirements (e.g. control) is estimated at $50,000. A preliminary estimate of installing a combined heat and power system to the re-capitalized gasifier set-up would be $365,000. The equipment cost break down is shown in Table 23.

Table 22 Combined Heat and Power Cost Estimate

Equipment	**Cost**
Scrubber	$ 120,000
Filter/De-mister	$ 60,000
Genset	$ 110,000
Electrical	$ 25,000
Plumbing/Control	$ 50,000
Total	**$ 365,000**

5 Summary

The cost of all fluidized bed and boiler system modifications are estimated as $205,136. A new control and monitoring system including capability for on-line syngas analyses and which will allow operation of the unit in both gasification and combustion modes was estimated at $220,045. The cost of the reactor and control system modifications to make the gasifier operational is thus $425,181. The cost summary is provided in Table 24.

Table 23 Complete List of Estimated Costs

Fluid Bed System Re-design	
Elevation and Support	$ 48,535
Pre-Heat Burner	$ 5,148
Air Distributor	$ 38,652
Ash Cooling and Removal	$ 19,190
Emergency Exhaust	$ 21,590
Syngas Transport	$ 21,391
Boiler B1 Mods	$ 24,230
Refurbishment Labour	$ 26,400
Section Total	**$ 205,136**
Controls & Data Acquisition	
Instrumentation	$ 17,590
Gas Analysis/Monitoring	$ 36,500
Cabling	$ 2,900
Control System/ PLC	$ 7,505
Burner Management Systems	$ 11,000
Control Panels	$ 11,500
Miscellaneous	$ 17,400
Labour	$ 115,650
Section Total	**$ 220,045**
Emissions Control	
Ventrui Scrubber	$ 100,650
Flue Gas Path/Fan Mods	$ 92,000
Section Total	**$ 192,650**
TOTAL	**$ 617,831**

There are a number of options which can be implemented in order to control emissions, namely particulate emissions. Other emissions such as NO_X and SO_2 are minimized by the fuel specifications and will not require additional control. An oxygen sensor has been included in the control for B1 boiler and this will allow proper control of excess levels in the boiler which will ensure that carbon monoxide levels are minimized. Control of particulate emissions will however require a secondary or external device. A number of options were considered:

- A Venturi scrubber at a cost of $100,650 with emissions of 35 mg/Nm^3
- An ESP at a cost of $362,000 with emissions of 30-35 mg/Nm^3
- A Wet ESP at a cost of $474,600 with emissions of 15 mg/Nm^3

Owing to small size for this type of device, the ESP performance is not superior to a Venturi scrubber and therefore the choice is between the scrubber and the Wet ESP. Given that the scrubber offers potential increased heat recovery from the scrubber water and therefore higher efficiency, unless there are regulatory requirements for the lowest level particulate emissions, it is recommended that the gasifier re-capilization project include the Venturi scrubber as the emissions control technology. When the costs of flue gas duct modifications and ID fan relocation are considered, this brings the total cost of the project without consideration of an additional fuel feed system to $617,831.

Note: Another approach to reducing emissions would be to additionally scrub the syngas prior to combustion in the boiler. The combustion in the boiler would then be of essentially clean gas and should easily meet the 15 mg/Nm^3. The scrubber between the gasifier and the boiler would also necessitate an additional heat exchanger and the additional cost of installing these systems would be $120,000. One benefit of carrying out this additional syngas clean-up would be that the syngas would already be substantially cleaner for potential future installation of a reciprocating engine for power generation.

A number of options have been studied for additional and alternate fuel feed systems. The existing bunker system is marginally adequate in terms of capacity with one days' storage, however the system is prone to operational problems. Unless the wood chip quality (especially size) is carefully monitored, the system is prone to jamming and the design makes clean-out very time-consuming. This could be remedied to a certain extent by demanding fuel meet certain specifications. For wood chips this would be:

- Maximum dimension of 2"
- Less than 5 % fines (particles < .5 mm)
- Moisture Content: 10 to 20%
- Ash (and dirt): 0-1.5%
- Heating Values: >18.5 MJ/kg on a dry basis

The capacity could be extended by using pellets and filling on average once every 3-4 days, however a better solution would be to install a higher capacity and more "automated" feed system. In terms of ease of operation the recommended approach would be to use wood pellets and install a pellet silo (in essence a modified grain silo). Such a system could be installed for $46,616 and would provide 55 tonnes of on-site storage, enough for 4 days of operation at maximum capacity. This approach would require the least operator involvement and assure smooth gasifier operation. The addition of a pellet storage system would allow the gasifier to be co-fired (i.e. fired simultaneously) with pellets and an alternate fuel, e.g. wood chips, cardboard wastes.

The drawback to pellet use is that pellets are not currently produced in the Yukon and therefore the pellet fuel would be expensive, estimated at $300 per tonne against cost of wood chips of approximately $150 per tonne. Note that these fuel prices are double what is commonly available in "Southern Canada". CETC-O has carried out designs for three wood chips options:

- a small covered 50 tonne bin with a walking floor
- a large 200 tonne bin with a walking floor and automated levelling system
- a dual fuel auger system which would need to be in an enclosure

All of these options would require installation of a concrete pad and although potential locations exist near the boiler house, the exact selection of site requires input from the Yukon Department of Highways and Public Works. The cost of these options are $278,647 for the small bin; $718,647 for the large bin and $483,004 for the dual fuel auger system. The dual fuel system is high as the price already includes $284,000 for an enclosure. One additional note is that the small covered bin would require that the fuel supplier invest in a walking floor truck which requires and investment of approximately $100k.

The option recommended by CETC-O is the installation of the pellet silo at a cost of $46,616. This option includes refurbishment of the existing bunker (including additional screens) for use with alternate fuels. Note that installation of the pellet system would not preclude installation of one of the other wood chip options at a later date. It would however considerably facilitate the re-capitalization process; require less operator involvement (thus reducing the number of additional operators required from two for wood chips to one for pellets) and finally, this would be the start of establishing a market for pellets in Whitehorse, thus opening up the potential for a local pellet production plant to be established.

The overall cost based on the above recommendations thus comes to $664,616. The supervision of installation and commissioning by CETC-O staff has been estimated at $100,000 which brings **the total cost of recapitalization to $764,616 plus any applicable taxes.** Table 25 shows the cost breakdown for the systems. This does not include taxes (i.e. GST) and also does not include the suggested addition of a second scrubber for the syngas to ensure minimal emissions and also as a prelude to potential power generation from the gasifier.

Table 24 Cost Summary Two Cost Scenarios – Pellets vs Wood Chips

		Pellet System	Wood Chip System
Fluid Bed System Re-design			
Elevation and Support	$ 48,535		
Pre-Heat Burner	$ 5,148		
Air Distributor	$ 38,652		
Ash Cooling and Removal	$ 19,190		
Emergency Exhaust	$ 21,590		
Syngas Transport	$ 21,391		
Boiler B1 Mods	$ 24,230		
Refurbishment Labour	$ 26,400		
Section Total	**$ 205,136**	$ 205,136	$ 205,136
Controls & Data Acquisition			
Instrumentation	$ 17,590		
Gas Analysis/Monitoring	$ 36,500		
Cabling	$ 2,900		
Control System/ PLC	$ 7,505		
Burner Management Systems	$ 11,000		
Control Panels	$ 11,500		
Miscellaneous	$ 17,400		
Labour	$ 115,650		
Section Total	**$ 220,045**	$ 220,045	$ 220,045
Emissions Control			
Venturi Scrubber	$ 100,650	$ 100,650	$ 100,650
ESP	$ 362,000		
WESP	$ 474,600		
Flue Gas Path/Fan Mods	$ 92,000	$ 92,000	$ 92,000
Fuel Systems			
Pellet Storage	$ 26,290	$ 26,616	
Small Chip Bin (50 t)	$ 278,647		$ 278,647
Large Chip Bin (200 t)	$ 718,647		
Dual Chip Fuel (120 t)	$ 483,004		
Cement Pad	$ 20,000	$ 20,000	$ 20,000
Enclosure (Dual Chip Fuel)	$ 284,000		
CETC-O Project Mgt	$ 100,000	$ 100,000	$ 100,000
GRAND TOTAL		**$ 764,121**	**$ 1,016,478**

6 Economic Feasibility

An economic feasibility evaluation for this project especially given its history of proponents and detractors is fraught with risk – someone is bound to disagree with some of the assumptions. The approach taken here is to estimate the total cost of providing 6,000,000 kWh of heat to Yukon College for a variety of options: fuel oil, secondary electricity, wood chips and wood pellets. The following assumptions have been made in this analysis:

Capital Cost of Re-capitalization for pellet gasification: $ 764,121

Capital Cost of Re-capitalization for wood chip gasification: $1,016,478

Capital Cost of Fuel Oil Firing Emissions Control: $ 192,650

Additional labour cost for gasifier operation: $65,000/year

Additional O&M costs for gasifier operation: $25,000/year

Annual heating requirement: 6,0000,0000 kWh

Wood calorific value: 19.9 MJ/kg

Fuel Oil Calorific value: 45.3 MJ/kg

Oil-fired thermal efficiency: 80%

Wood-fired thermal efficiency: 75%

Electric heating efficiency: 100%

The following are Year Zero Fuel Prices and relatively high prices for biomass have been assumed – these are in essence “high market” prices, however this has been chosen to avoid the appearance that this analysis is favouring the re-capitalization of the gasifier:

Pellets:	$300/ODT
Wood Chips:	$150/ODT
Fuel Oil:	$1/litre
Electricity:	80% of cost of Fuel Oil (8.88 ¢ per kWh based on oil @$1)

The following is the projected increases in cost of operating the heating plant (only labour and O&M above the current levels are included):

Pellets and Wood Chips increase at inflation rate of 2% per annum

Fuel Oil increase at 5% per annum

This inflation is a reasonable assumption based on the recent past. The fuel oil increase is if anything very low. At the time of this writing the world is in a recession and the demand for oil has dropped resulting in lower prices. One year ago oil hit all-time records. In order to come up with a reasonable number the authors consulted Don Roberts of CIBC World Markets. His data show that the marginal cost of new oil supply has increased since 2004 by an average of $10 per barrel per year. This is a more significant long-term evaluation than the speculative price of oil on the market. This increase currently represents an increase of approximately 10% per year. Once can argue that this is therefore a reasonable projection, but if one considers that demand will drop as the price goes up then assuming a 5% annual increase in the oil seems a safe assumption. As noted earlier critics may choose their favourite figures, the authors of this report are attempting to present a "realistic" evaluation which does not depend on rapidly escalating costs and therefore have chosen 5% as the annual increase in oil prices.

The electricity rate increase is based on inflation and the oil price increase: Average the increase in electricity due solely to inflation (2%) with the increase corresponding to 80% of the increase in the cost of heating oil. The rationale behind this is that a portion of the electricity will be derived from hydroelectric sources and some will be derived from imported oil. As the price of oil rises, electricity will also be pushed up but the rise will be buffered by the hydroelectric capacity.

The unit "fuel" price for all the fuelling options based on these assumptions are shown in Figures 30 and 31. The unit prices at the end of 25 years are:

Pellets:	$482/ODT
Wood Chips:	$241/ODT
Fuel Oil:	$3.22/litre
Electricity:	28.7 ¢ per kWh

Figures 32 and 33 present the cumulative costs of heating Yukon College for 10 years and 25 years. Figure 10 shows the various paybacks for different options. Electricity starts as the least expensive and is overtaken in year 4 by wood chips which then remains the least expensive option. Electricity remains less expensive than pellets until year 10 at which point pellets become favoured. Fuel oil is only less expensive than the biomass options until year 2-3. After year 4, fuel oil is always the most expensive option.

The cumulative costs of heating Yukon College over a 25 year period are shown in Figure 33 and can be summarized as:

Pellets:	$17.6 M
Wood Chips:	$10.5 M
Fuel Oil:	$32.0 M
Electricity:	$21.5 M

All this of course assumes that all the existing equipment has a life-time of 25 years, i.e. no cost of major equipment replacement is included.

Based on this analysis the best strategy would appear to be to carry out the re-capitalization of the gasifier but maintain the electricity capability to take advantage of potentially “cheap” power. The gasifier should be equipped with the capability to fire pellets which is the least technically challenging option but the gasifier’s exisiting wood chip system should be integrated into the controls so that the gasifier could also operate on wood chips which are the potentially lowest cost fuel. Fuel oil heating is by far the most expensive option and is not recommended.

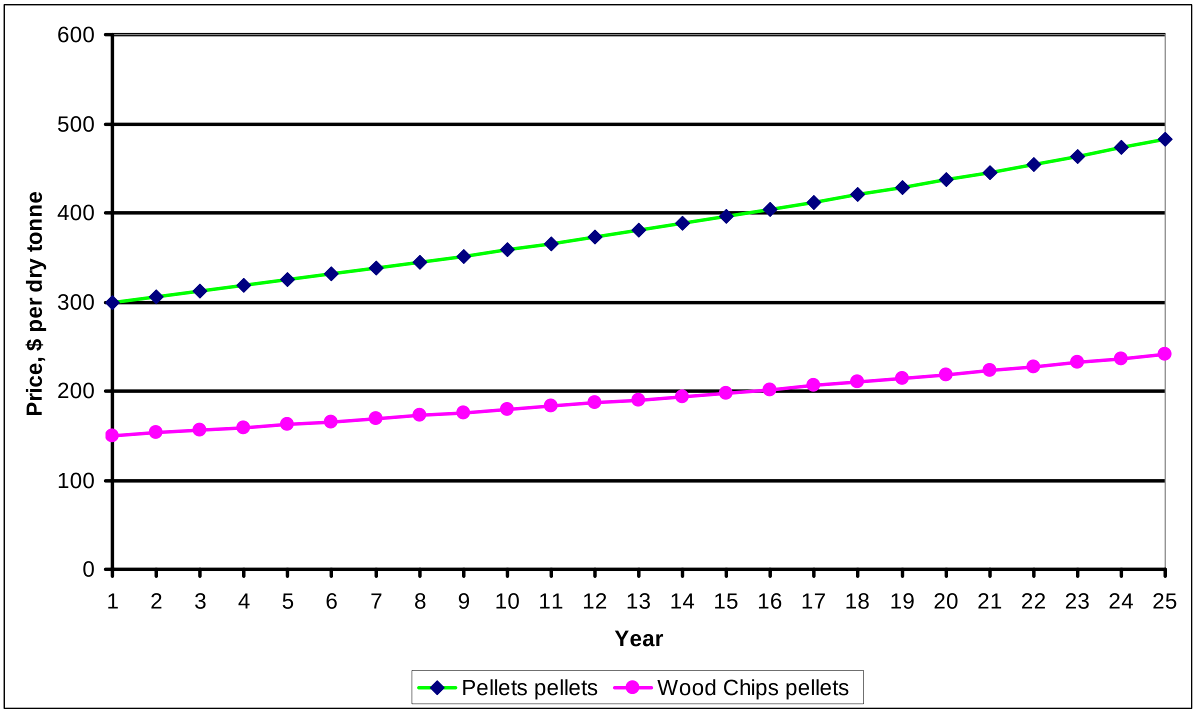

Figure 30 Unit cost of biomass fuels

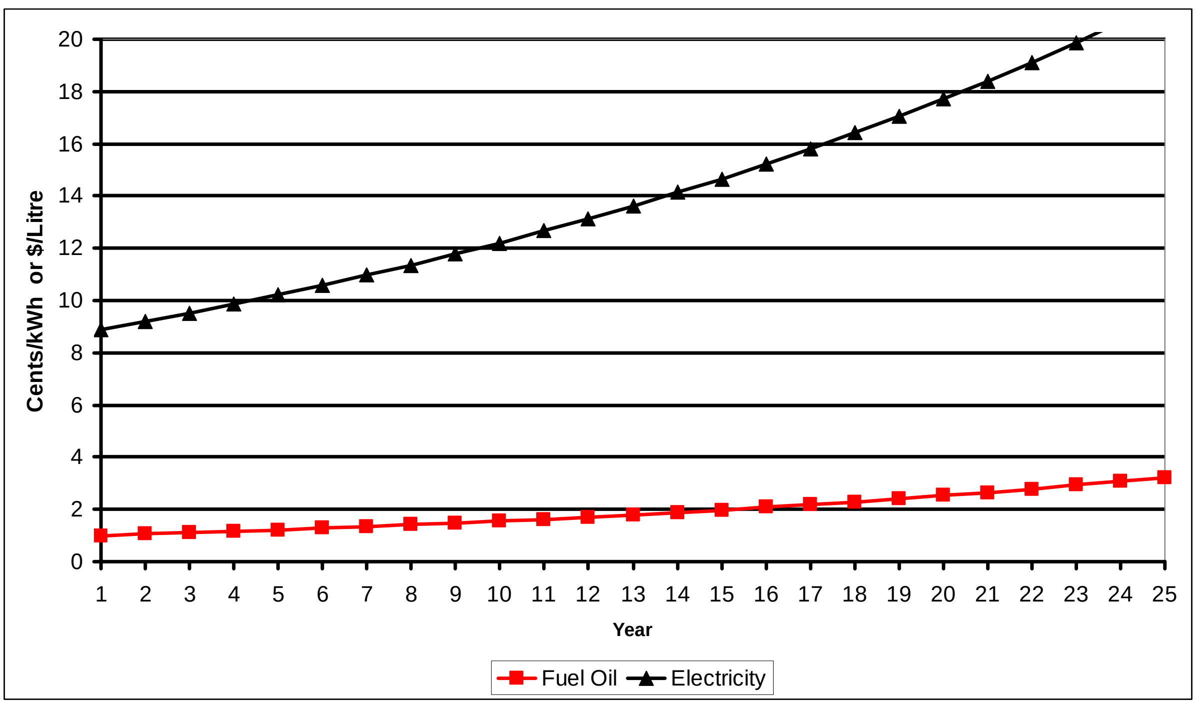

Figure 31 Change in unit cost of electricity and oil

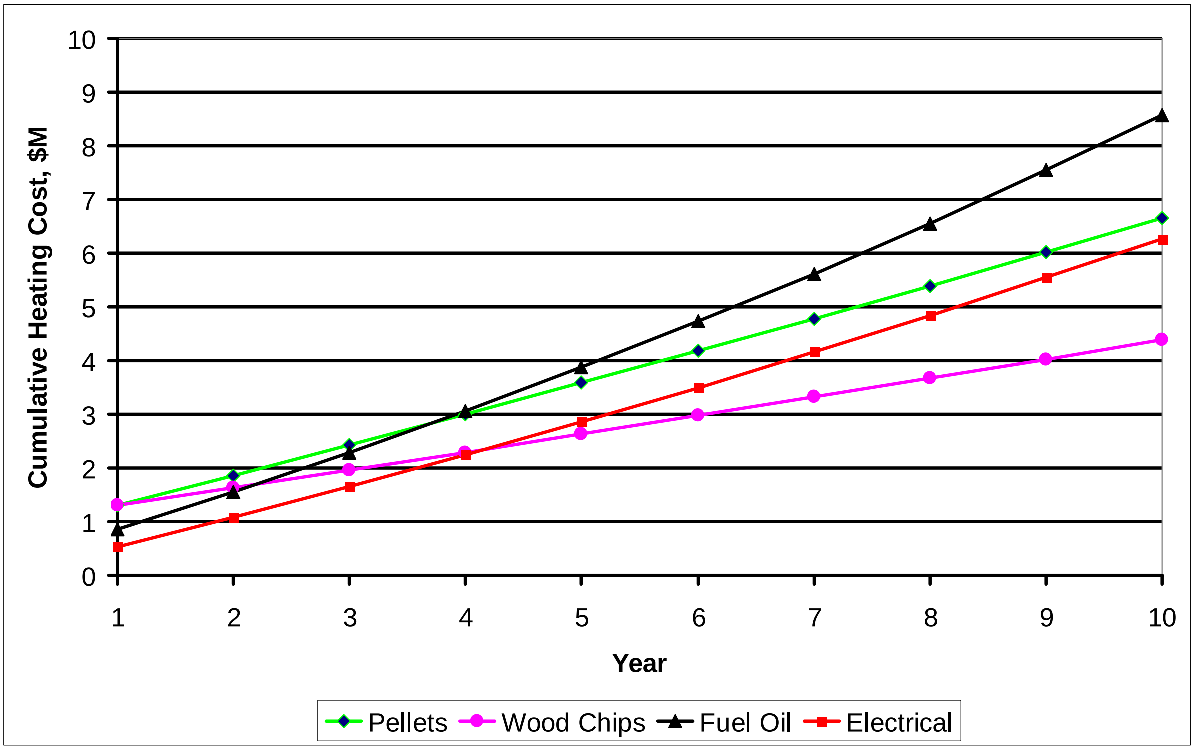

Figure 32 Cumulative Heating Costs for 10 Years

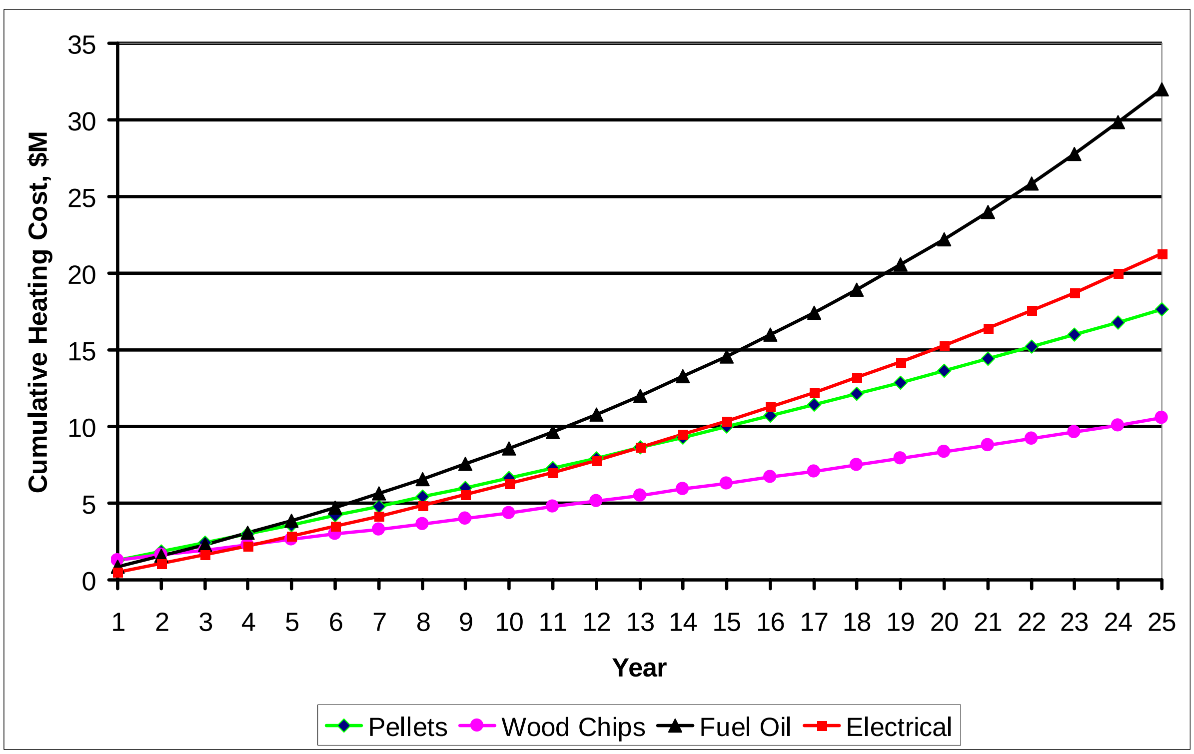

Figure 33 Cumulative Heating Costs for 25 Years

7 Recommendations

Re-capitalization of the Yukon College Gasifier is recommended at a cost of $425k for fluidized bed, boiler and control system modifications.

A pellet storage and feed system is recommended for trouble-free operation although the present feed system should be retained for research into alternate local fuels. The pellet storage system cost was estimated at $47k.

Given that a scrubber offers potential increased heat recovery from the scrubber water and therefore higher efficiency it is recommended that the gasifier re-capitalization project include a Venturi scrubber ($101k) as the emissions control technology with expected emissions below 35 mg/Nm^3

Implementing these recommendations (plus $100k engineering fees) brings the total re-capitalization cost to $765k. Based on relatively high cost of pellets of $300/tonne and one additional operator an economical evaluation shows that electricity starts as the least expensive and is overtaken in year 4 by wood chips which then remains the least expensive option. Electricity remains less expensive than pellets until year 10 at which point pellets become favoured. Fuel oil is only less expensive than the biomass options until year 2-3. After year 4, fuel oil is always the most expensive. Based on this analysis the best strategy would appear to be to carry out the re-capitalization of the gasifier but maintain the electricity capability to take advantage of potentially "cheap" power. The gasifier should be equipped with the capability to fire pellets which is the least technically challenging option but the gasifier's exisiting wood chip system should be integrated into the controls so that the gasifier could also operate on wood chips which are the potentially lowest cost fuel. Fuel oil heating is by far the most expensive option and is not recommended.

In the event that the Yukon Government chooses to replace the existing facility with a new biomass-fired system, CETC-O recommends a modular pellet furnace based system which could be installed at a cost of $786k (+$101k for Venturi scrubber). This figure does not include removal of existing equipment, building modifications or engineering fees.

The Yukon College gasifier would be an ideal research facility which would allow the Yukon Government to establish a Canada-leading Centre of Excellence on pellet utilization, renewable combined heat and power for northern communities, liquid bio-fuels and hydrogen economy developments. As a first stage in this initiative, a combined heat and power system based on the re-capitalized gasifier could be established for approximately $365k.

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Appendix A

Drawings

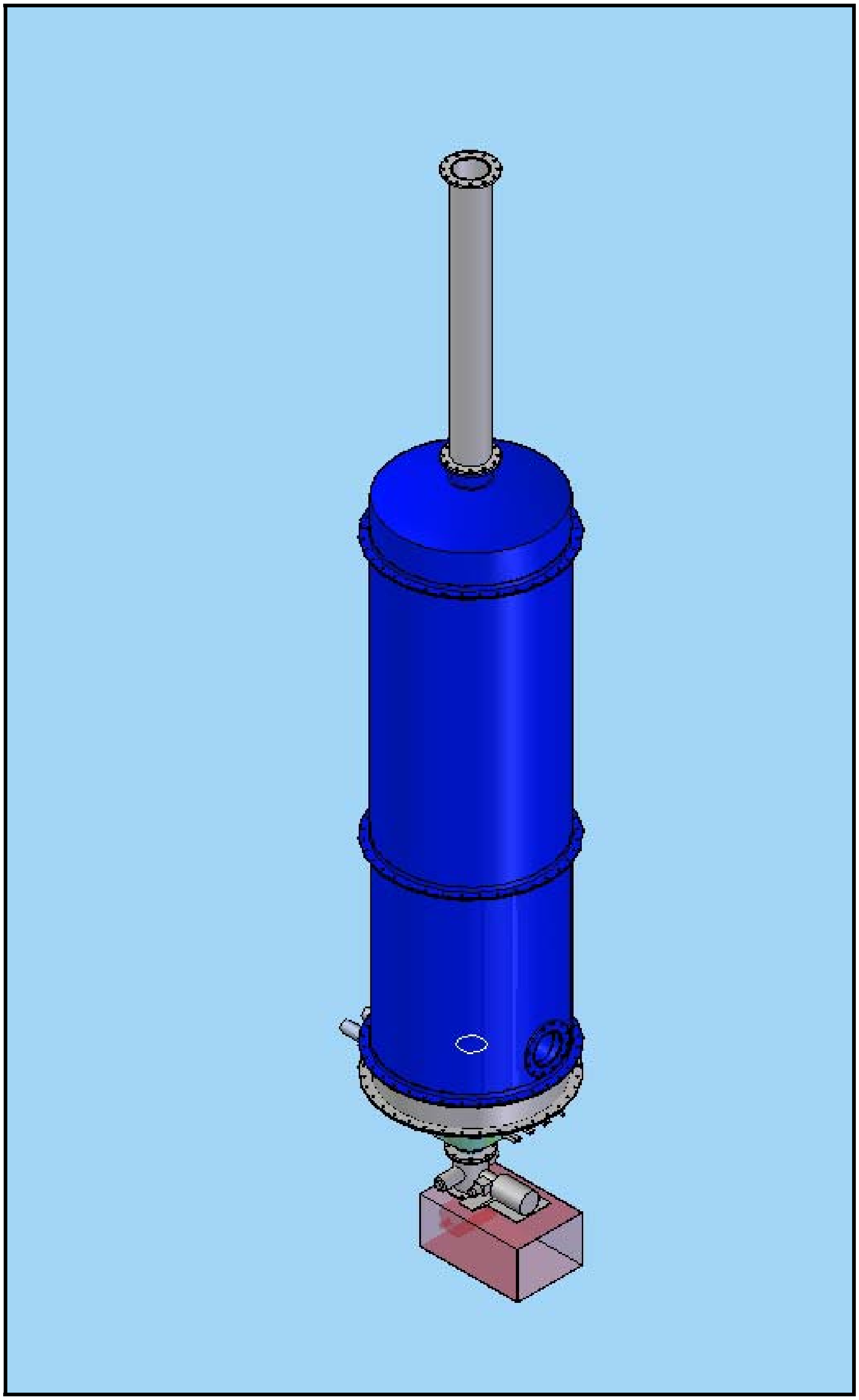

Figure 34 Rendered drawing of the Yukon gasifer with modifications

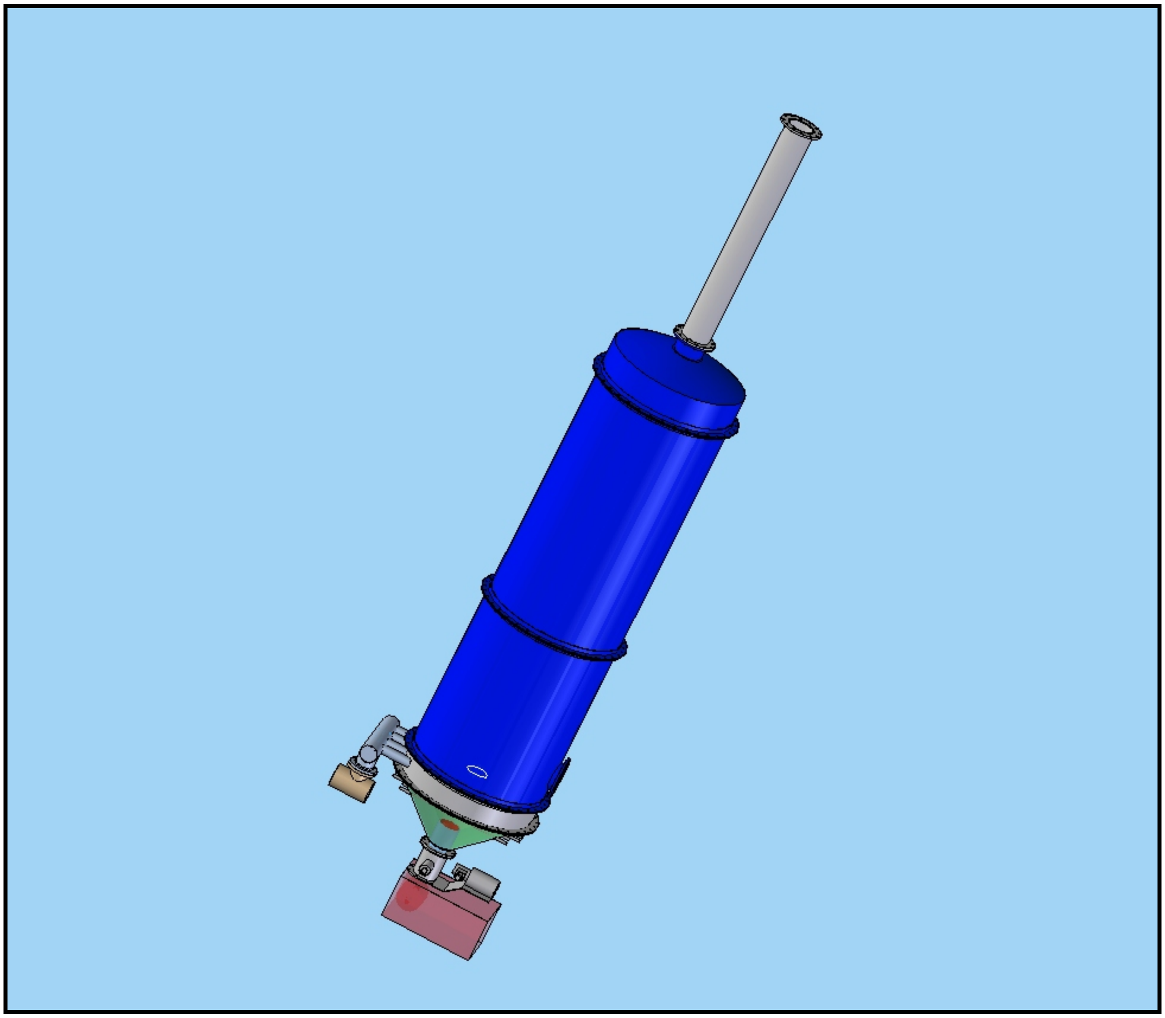

Figure 35 Rendered drawing of the Yukon gasifer with modifications

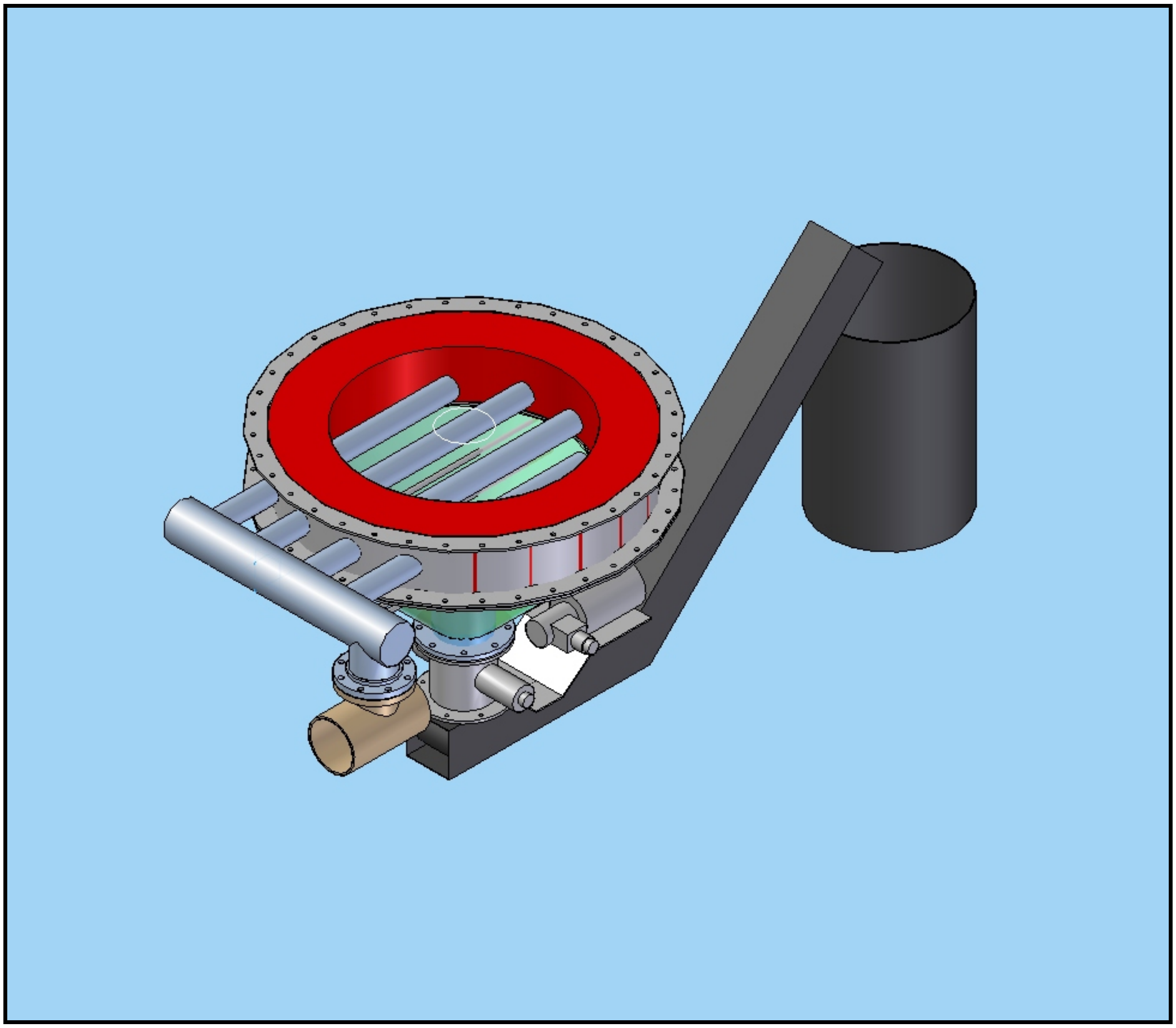

Figure 36 New bottom section and ash removal

Appendix B

Detailed Cost Estimates

ITEM DESCRIPTION		
EQUIPMENT TYPE	**SPECIFICATIONS**	**TOTAL COST**
Instrumentation		**$ 17,590.00**
Pressure Transmitter (gasifier)	-5 - 40 kPa / 4-20mA output / 24VDC supply / HART compatible	$ 6,600.00
Pressure Transmitter (back end/boiler)	-10 - 10 inW / 4-20mA output / 24VDC supply / HART compatible	$ 3,300.00
Thermocouple (complete system)	K-Type / 24-36" length / 3/8" diameter / Industrial Head	$ 1,190.00
Thermal Mass Flowmeter (pri. air)	0 - 900 cfm air @ 25deg. C @ 3psi (convert to kg/h)	$ 6,500.00
solenoid vlaves	8" for emergency exhaust and dilution	$ 16,000.00
Gas Analysis/Monitoring		**$ 36,500.00**
Sample Conditioning System	Actual cost will depend on final I&C design.	$ 9,000.00
Gas Analyzers (syngas)	Actual cost will depend on final I&C design.	$ 18,000.00
In-situ Oxygen Analyzer (boiler outlet)	Actual cost will depend on final I&C design.	$ 4,500.00
Ambient Gas Monitoring	Actual cost will depend on final I&C design.	$ 5,000.00
Cabling		**$ 2,900.00**
K-Type T/C Extension Wire	1000ft spool / 20 AWG / 2 conductor / shielded	$ 900.00
Signal Wire	1000ft spool / 20 AWG / 2 conductor / shielded	$ 900.00
Signal Wire	500ft spool / 20 AWG / 2 pair / shielded	$ 500.00
10Base-T Communication Wire	1000ft spool	$ 600.00
Control System / PLC		**$ 7,505.00**
Direct Logic 06 PLC	20 Digital In / 16 Digital Out / AC Power Supply	$ 518.00
LCD Display for PLC	16 Character X 2 Rows	$ 146.00
TC Option Module	4 TC Input Channels	$ 796.00
AI Option Module	8 4-20mA Input Channels	$ 258.00
AO Option Module	1 4-20mA Output Channels	$ 189.00
Com Module	Ethernet Communication Module	$ 199.00
User Interface	C-More Colour Touch Screen / 15" TFT / With USB & Ethernet Support	$ 4,550.00
C-More Software	Touch screen programming software	$ 129.00
Directsoft 5	PLC programming software (3 PLC license)	$ 395.00
KEP Direct	OPC server software to communicate with LabVIEW	$ 295.00
PC Programming Cable		$ 30.00
Burner Management Systems		**$ 11,000.00**
Plasma Ignitor	Actual cost will depend on final gasifier design.	$ 3,000.00
BMS Hardware	Actual cost will depend on final gasifier design.	$ 8,000.00
Control Panels		**$ 11,500.00**
PLC Enclosure	Includes electronic components. Actual cost will depend on final I&C design.	$ 5,000.00
VSD Enclosure	Includes electronic components. Actual cost will depend on final I&C design.	$ 6,500.00
Miscellaneous		**$ 17,400.00**
Control Computers	Specs to follow	$ 6,000.00
Network Equipment	Specs to follow	$ 400.00
Computer/Analyzer Rack	Specs to follow	$ 2,000.00
Electrical Components	Conduit, junction boxes, fittings, unistrut, etc	$ 6,000.00
Instrument Process Connections	Various pipe and Swagelok fittings and tubing	$ 3,000.00
Labour	**All labour costs in estimated man hours**	**$ 115,650.00**
Instrumentation and Controls Technician		$ 44,100.00
Senior Technician		$ 20,100.00
Electrician		$ 51,450.00
Total (taxes extra)		**$ 220,045.00**
All costs are estimated based on previous projects of similar scope. Taxes are extra.		

Feed Systems			
Covered trailer fed bin		**$**	**278,647**
Covered trailer fed bin	50 t of storage, covered	$	200,000
fuel screener	BM&M	$	4,824
cement pad		$	20,000
elevator to screener, conveyor to hopper, stairs, cover for screener, pad for screener		$	20,000
B3030HSDC Kubota Tractor	tractor w heated cb, forks and bucket	$	33,497
Hole in the wall	2 workers for 2 hrs	$	326
Conveyor feed bin		**$**	**718,647**
receiving bin	verbal estimate based on slightly larger units	$	200,000
200t storage bin & controls		$	370,000
conveyors		$	50,000
fuel screener	BM&M	$	4,824
cement pad		$	40,000
elevator to screener, conveyor to hopper, stairs, cover for screener, pad for screener		$	20,000
B3030HSDC Kubota Tractor	tractor w heated cb, forks and bucket	$	33,497
Hole in the wall	2 workers for 2 hrs	$	326
Covered dual feed system		**$**	**483,004**
conveyors, screws and drives	based on a similar system in a greenhouse installation	$	120,000
Stairs over conveyor to hopper		$	300
cement pad	2 bays with total of ~120 t of storage	$	40,000
support and cover		$	284,057
fuel screener	BM&M	$	4,824
B3030HSDC Kubota Tractor	tractor w heated cb, forks and bucket	$	33,497
Hole in the wall	2 workers for 2 hrs	$	326
Pellet System		**$**	**46,616**
Storage Silo		$	26,290
cement pad		$	20,000
Hole in the wall	2 workers for 2 hrs	$	326
New Bottom		**$**	**35,652**
Duct with Y anchors		$	4,887
Cone with Y anchors		$	6,822
3"SCH 40x21'		$	551
3"SCH 80x21'		$	1,211
Drive Assembly	DC Vari Speed AC/DC controller 6"x 6"	$	7,888
Refractory	mix and labour	$	14,293

Ash Removal			
Lifting the unit, removal of old section, installation of new section		**$**	**26,000**
Adjusting Feed hopper and air preheater		**$**	**15,000**
Removing & reassempling pieces of the feed system; installing new feed auger, removing air manifold		$	15,000
Air System		**$**	**13,000**
Manifold for sparge tubes		$	3,000
movable frames	fan, pre-heater, air lock	$	6,000
Flange additions	flexibility to move fan, preheater and feed port	$	4,000
Preheater		**$**	**5,148**
Beckett CF1400		$	2,228
Air Tube		$	117
Flange kit	12 1/4"	$	150
Nozzle	45 degree	$	13
Installation	16 hrs at 165	$	2,640
Boiler Upgrades		**$**	**23,980**
Fabrication of syngas lances and caps		$	18,980
Installation of lances & caps		$	2,000
refractory and patching mortar	mix and labour	$	3,000
Back End		**$**	**92,326**
New pressure exhaust installed	double walled from ID fan to APC equipment	$	92,000
Hole in the wall	2 workers for 2 hrs	$	326
Flare System		**$**	**16,916**
flare, ignighter		$	11,310
installation	32 hrs at 165	$	5,280
Hole in the wall		$	326
Emissions Controls Systems			
ESP & stack installed		$	220,000
Venturi Scrubber	TurboSonic - "theoretically can remove up to 15mg/m3"	$	65,650
Scrubber & stack installation		$	35,000
WESP equipment	TurboSonic - "will easily achieve removal up to 15mg/m3"	$	399,600
WESP & stack installation		$	75,000
Painting the systm & gen labour		**$**	**26,400**
Tools, fittings, nuts and bolts		**$**	**8,265**
Inspections & permits		**$**	**10,000**
CETC Project Management and logistics		**$**	**100,000**
Labour & operating manual		$	80,000
travel		$	20,000

Appendix C

Application for Air Emissions Permit

Yukon
Environment

Air Emissions Regulation
APPLICATION FOR AN AIR EMISSIONS PERMIT
PART I – GENERAL

- Applicants should ensure that they:
  - are familiar with the *Air Emissions Regulation* (Environment Act).
  - complete all applicable sections, legibly printing or typing all information.
  - initial each completed page in the space provided.
  - complete the signature block at the end of the form.
  - submit all required attachments, including the permit fee and all applicable activity-specific form(s).
- **A fee of $100** is payable to the **Government of Yukon** on submission of this application.
  There is no fee for the renewal or amendment of an active permit.
- A pre-permit inspection may be conducted prior to the issuance of any permit.
- An assessment of the activity you are undertaking may be required under the Yukon Environmental and Socio-Economic Assessment Act (YESAA).
- Additional information may be required upon receipt of this application.

The original completed and signed application form should be mailed or delivered to your local government office or:

Environment Programs Branch (V-8)
Department of Environment
Government of Yukon (located at 10 Burns Road, Whitehorse)
Box 2703
Whitehorse, Yukon Y1A 2C6

For additional information:
Phone: (867) 667-5683 or 1-800-661-0408 ext. 5683 Fax: (867) 393-6205
web: http://environmentyukon.gov.yk.ca/monitoringenvironment/regulations.php
email: envprot@gov.yk.ca

PLEASE READ CAREFULLY AND FILL OUT ALL SECTIONS

❖ PART 1 – CONTACT AND SITE INFORMATION

A. Name and address of applicant

Contact name and position title ______ Phone # ______

Business name or government agency/branch/department ______ Fax # ______

Mailing Address ______ Postal Code ______

Email Address ______

Name (person or business) to appear on permit ______

B. Who is directly responsible for the activity requiring an Air Emissions Permit?
☐ **same as (1) above, or:** *(For multiple site locations, list on a separate sheet).*

Contact name and position title ______ Phone # ______

Business name or government agency/branch/department ______ Fax # ______

Email Address ______

C. Where will the source of the air emissions be located?
☐ **same as (1) above, or:** *(For multiple site locations, list on a separate sheet).*

Mailing Address ______ Postal Code ______

Street and/or Legal Address ______

D. Who owns the land on which the source of air emissions will be located?
☐ **same as (1) above, or:** *(For multiple site locations, list on a separate sheet).*

Applicants not owning the land on which the source is to be located ***must include*** *with this application a letter from the landowner authorizing the intended activity on their property.*

Applicant's initials ______ Page 1 of 4

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E. Is the land leased? If so, by whom?

____

❖ PART 2 – ACTIVITIES REQUIRING AN AIR EMISSIONS PERMIT

Check off the activity(ies) that apply to your operation and complete the applicable site-specific information form(s).

- ☐ Manufacturing asphalt
- ☐ Production/ Exploration of Oil and Natural Gas resulting in release of combustion products from flaring or burning
- ☐ Quarrying, crushing and screening of stone, clay, shale, coal or minerals in an active excavation area covering an area greater than 4 hectares
- ☐ Processing or handling of coal at a rate of greater than 5 million BTU per hour
- ☐ Operation of equipment capable of generating, burning or using, according to the manufacturer's specifications, heat energy equivalent to or greater than 5,000,000 BTU/hr
- ☐ Burning of waste by:
  - ☐ Incinerating:
    - ☐ Operation of incinerators capable of burning, according to the manufacturer's specifications, more than 5kg of solid waste per day
    - ☐ Incinerating special waste, as defined in the *Special Waste Regulations*
    - ☐ Incinerating contaminated soil containing any contaminant in excess of the generic numerical soil standard or the matrix numerical soil standard as defined in Schedules 1 or 2 of the *Contaminates Sites Regulation* and having less than 3% hydrocarbons and or levels greater than those specified in Part 2, Appendix 4 of the *Federal Transportation of Dangerous Goods Regulation*
  - ☐ Open burning of more than 5 kg/day of solid waste

Note:

***Incinerating** means combustion in an incinerator, which is equipment used for the burning of waste or contaminated soil where the air intake and combustion temperatures may be controlled.*
***Open burning** refers to the combustion of material without control of the combustion air and without a stack or chimney to vent the emitted products of combustion to the atmosphere.*

- ☐ Operation of electricity generating facilities with a maximum nameplate capacity equal to or more than 1.0 Megavolt ampere (at unity power factor equivalent to 1.0 megawatt).
- ☐ Use of fuel with sulphur content in excess of 1.1% for:
  - ☐ Heating
  - ☐ Generating steam or electricity
  - ☐ Combustion in industrial process
- ☐ Storage or handling of solid, liquid or gaseous materials or substances in a manner that causes or may cause an adverse effect.
- ☐ This application been required by the Minister for any of the following reasons:
  - ☐ Opacity of emissions exceeds 40%
  - ☐ Release of a contaminant to the air that may cause or is likely to cause irreparable damage to the natural environment
  - ☐ In the opinion of a health officer, the release of a contaminant to the air that may cause actual or imminent harm to public health or safety

Applicant's initials _______

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PART 3 – OTHER PERMITS/APPROVALS

A. Have you applied for another permit(s) under Yukon's Environment Act regulations:

- ☐ Solid Waste Regulations
  - ☐ operation of a solid waste disposal site
  - ☐ operation of a commercial dump
  - ☐ other:
- ☐ Special Waste Regulations
  - ☐ disposal of special waste
  - ☐ other:
- ☐ Other Regulation:

B. Is your project subject to review under the Yukon Environmental & Socio-economic Assessment Act (YESAA)?

- ☐ yes: YESAA Project Number: ________________________________
- ☐ no

❖ PART 4 – EMISSIONS AND SOURCE INFORMATION

A. Describe the type and quantity of the contaminants that may be released into the air. If available, provide results of any stack tests or dispersion modelling that has been conducted for the potential emissions. .

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B. Provide (as an attachment) a set of plans/drawings of the facility clearly showing the layout of the following as they apply:

- The location of relevant process equipment,
- The point or points of discharge to the atmosphere,
- Building dimensions,
- Stack heights,
- The north and prevailing wind directions, and
- The scale or approximate scale of the drawing.

C. Provide (as an attachment) a map or aerial photograph, on a scale of 1:50,000 detailing the location of the facility, homes, buildings, roads and other adjacent facilities within a five kilometre radius of the source(s).

D. Provide a description of any measures to be taken to reduce the amount of air emissions released from the facility and/or the concentrations of contaminants in the air emissions.

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Applicant's initials _______

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E. Provide a description of any measures to be taken to measure and/or mitigate the effects of the release of air contaminants on the surrounding environment.

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F. Provide a description of any equipment or devices the applicant intends to use to monitor the release of contaminants into the air at the point(s) of release. Include information on contaminants monitored, monitoring frequency, action levels and responses, and any other relevant information.

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G. Provide manufacturer's specifications for any equipment which has the potential to produce emissions.

H. List staff certified to observe opacity:

Name of Staff	Training Institution	Date Last Trained

I, ______________________________ [print name clearly], am the authorized representative of ______________________________ [business/person responsible for source or activity], and I certify that the information provided on this application form is correct and complete to the best of my knowledge.

All attachments and site-specific information forms comprise part of this application.

______________________________ Signature of applicant

_______________ Date

Number of attachments: _______

This information is being collected under the authority of Section 11 of the *Air Emissions Regulation*. For further information, contact the Environmental Programs Branch at (867) 667-5683 or toll free at 1-800-661-0408 extension 5683.

Applicant's initials _______

Appendix D

External Estimates and Quotes

NATURAL RESOURCES CANADA DOES NOT ENDORSE ANY SPECIFIC MANUFACTURERS

ALL QUOTES ARE SUPPLIED ON A CONFIDENTIAL BASIS