Report No. 110502

Prepared for:

St. Francis Xavier University

Antigonish 8 MW Biomass Cogeneration Plant - Feasibility Study

Final Report - Revised

March 15, 2011

CBCL

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Consulting Engineers

ISO 9001

Registered Company

Table of Contents

1 **Executive Summary** **1**

2 **Biomass** **5**

2.1 Introduction 5

2.2 Biomass Resource 5

2.3 Technologies 6

2.3.1 Grate Combustion 6

2.3.2 Fluidized Bed Combustion 7

2.3.3 Gasification 9

3 **Preliminary Regulatory Review** **11**

3.1 Environmental Issues 11

3.1.1 Greenhouse Gas (GHG) Reduction 11

3.2 Power Connections 12

3.3 Plant Operations 12

4 **Evaluation of Cogeneration Options** **13**

4.1 Introduction 13

4.2 Steam Load and Energy Assessments 14

4.3 General Criteria for Options 16

5 **Scope of Work** **17**

5.1 Existing Plant Summary 17

5.2 Cogeneration Plant Summary 17

5.3 Turbine/Generator System 17

5.4 Wood Biomass Boiler 19

5.5 Boiler Performance and Fuel Usage 19

5.6 Mechanical Balance of Plant 21

6 **Financial Feasibility Analysis – Cogeneration** **23**

6.1 Introduction 23

6.2 Cost Estimate 24

6.3 Financial Analysis Results 24

6.4 Sensitivity Analysis 26

7 **Conclusions and Recommendations** **28**

Appendices

A BFB Boiler Budget Price
B Steam Turbine Budget Price
C Financial Analysis

List of Tables

Table 1 Capital Cost Summary – Cogeneration Plant..3
Table 2 Summary of Financial Results – Cogeneration...3
Table 3 Monthly Steam Production...14
Table 4 Steam Turbine Performance...18
Table 5 Fuel Analysis – White Birch 20
Table 6 Boiler Performance - Full Load 8.0 MW Generator Output Avg Thermal Load .20
Table 7 Capital Cost Estimate...24
Table 8 Financial Summary...25

List of Figures

Figure 1 Nova Scotia Wood Harvest and Supply...6
Figure 2 Grate Fired Boiler (Courtesy B&W Canada)...7
Figure 3 Bubbling Bed Biomass Boiler (Courtesy B&W Canada)......................................8
Figure 4 Typical Biomass Gasification Plant – Gussing, Austria..9
Figure 5 Typical Gasifier – Nexterra – University of South Carolina 10
Figure 6 Monthly Steam Load 14
Figure 7 Peak Steam Loading 15
Figure 8 Sensitivity Analysis ROE vs Delivered Fuel Price 26
Figure 9 Sensitivity Analysis – Electricity Sales Price vs. Fuel Price for 10% ROE 27

1 EXECUTIVE SUMMARY

The purpose of this report is to evaluate the feasibility of installing an 8 MW gross (7 MW net) biomass cogeneration system in Antigonish. This system would supply electricity to the grid as well as steam to the existing St Francis Xavier University district heating system.

This report looks at the technical concepts of a cogeneration plant as well as a preliminary business model.

After reviewing the economics of this project it was determined that the project could be feasible with a 13% return on equity ROE if electricity can be sold to the grid at a price of 0.213$/kwh along with thermal energy sales at 16.00$/Million Btu. A further detailed study will be required to refine capital and operating costs.

Biomass cogeneration is a well established technology that is widely used in industrial applications such as pulp and paper mills and sawmills where an abundant and cheap source of biomass is available as a by-product of mill operations. Other areas where biomass cogeneration is sometimes feasible are areas that have adequate fibre resources and expensive imported fuel. The benefits of using locally harvested wood biomass for electrical and thermal energy production are numerous.

• The local economy benefits by providing jobs in the construction, operation and maintenance of the biomass cogeneration systems. The money stays in the local economy;

• Will provide employment in the forestry sector for harvesting, processing and transporting the biomass; and

• Local energy costs are less dependent on world prices for fossil fuels.

This report looks at the technical concepts of a cogeneration plant as well as a preliminary business model.

The proposed cogeneration concept would see a biomass fired combustion system (boiler) coupled with a steam turbine generator and condenser system. An extraction ports on the steam turbine will be used to supply steam as required to the university district heating network. There are other methods of producing energy from biomass such as gasification but they are generally more complex, less proven and more costly.

The equipment selected for this application is a high efficiency bubbling fluidized bed wood fired boiler as supplied by Babcock & Wilcox Canada (B&W). B&W is well known to Nova Scotia Power as the OEM boiler supplier to Tufts Cove and Trenton Power Plant. There are many applications of this technology including cogeneration plants at pulp and paper mills in Canada.

We performed sensitivity analysis around fuel cost and electrical sale price.

Of the operating biomass cogeneration plants we have seen in Atlantic Canada there seem to be some common elements.

1. Sawmills need boilers and steam for kiln drying lumber. There is no additional operating cost for installing and running a steam turbine generator. The fuel supply at sawmills is a by-product of their operation (bark, sawdust and shavings) and is essentially “free” to the mill.

2. Pulp and paper mills require boilers and steam for process requirements. The fuel supply for the boilers is “ hog fuel “ which is the bark that has been removed from the log prior to processing. Again this fuel is a byproduct of the operation and is very low cost to the mill.

We have had discussions with personnel from the Nova Scotia Department of Natural Resources as well as private operators in regards to the availability of hog fuel or waste fuel in the province. Current information that we have reviewed indicates that in Nova Scotia hardwood chips are trading in the range of 40$/tonne .

This report is a revision of a report completed in 2009. All Capital costs for this report were increased by 6% from the 2009 report. Also the sensitivity analysis range was extended to allow for potentially higher electricity sales prices.

As a note - In the economic analysis, carbon credits were not accounted for and neither was there any credit taken for electrical capacity factors.

Table 1 Capital Cost Summary – Cogeneration Plant

8 MW Cogeneration Plant Capital Cost Summary	
Boiler – B&W Bubbling Bed	$ 12,720,000
Steam Turbine Generator	$4,929,000
Condenser	$ 1,060,000
Cooling Tower	$ 424,000
Water Treatment	$ 398,000
Boiler Feed Pumps	$212,000
Deaerator	$127,000
Piping Tie-in to existing Distribution	$1,908,000
Mechanical BOP	$ 4,240,000
Electrical	$ 1,590,000
Instrumentation & Control	$ 954,000
Civil Works and Buildings	2,120,000
Subtotal	**$30,682,000**
Engineering and Project Management	$3,068,000
Contingency	$3,068,000
TOTAL	**$36,818,000**

Table 2 Summary of Financial Results – Cogeneration

Financial Summary		
Annual Electricity Exported	52.552	10^6 kWh
Annual Steam Exported	95,309	10^6 BTU
Annual Fuel Imported	89,672	Tonne (Green)
Total Investment	36,818	k CDN
Electricity Sale Price	0.213	$/kWh
Fuel Price	40	$/Tonne
Thermal Sale Price	16.00	$/ MMBtu
Inflation Rate	1.8	%
Plant Life	20	years
Return on Equity (ROE)	13	%

As can be seen from the financial summary, from the cogeneration option could be feasible if electricity could be sold at 0.213$/kwh.

COMMENTS

.1 **Scale.** At 8 MW (7 MW net) electrical output, the specific capital cost is high. This plant will cost approximately $4,500,000 per 1 MW electrical output. Larger biomass plants can be built for $1.5 - $2.0 million per MW.

.2 **Operating Labour Cost.** This plant will need to be manned with operators 24/7 because of the steam boilers involved and also because of the inherent nature of solid fuel handling equipment. The labour cost as a percentage of operating cost is very high as a result.

.3 **Fuel Cost.** This plant will probably end up purchasing whole tree chips. Based on conversations with NS Dept of Natural Resources and private forestry operators there is very little if any waste fuel available in this area. There is a sustainable resource of hardwood available, but the cost of providing this fuel is expensive.

We performed sensitivity analysis around several key operating variables such as fuel cost, electrical sale price and capital contribution from outside sources. These are presented in Section 6.

2 BIOMASS

2.1 Introduction

Biomass fuels such as wood have several advantages over conventional fossil fuels such as oil. The main advantage is that wood is a renewable resource that offers a sustainable dependable supply. One of the other main advantages of wood as a fuel is that it is carbon-neutral from a greenhouse gas perspective, that is, the amount of carbon dioxide CO_2 released from the combustion of wood is equal to the amount of CO_2 absorbed by the plant while it was growing. Wood fuel also contains minimal amounts of sulphur and burns at a much lower temperature which can reduce NOx and does not contribute to acid rain.

The principle economic advantage of wood biomass energy is the cost. wood is usually significantly less expensive than fossil fuels especially in remote communities where the transportation cost of fossil fuels is high. Also there are numerous local social benefits involved with wood biomass systems such as jobs created harvesting, processing and transporting the wood as well as jobs involved in the construction, operation and maintenance of the biomass plants. This is money that stays in the local community.

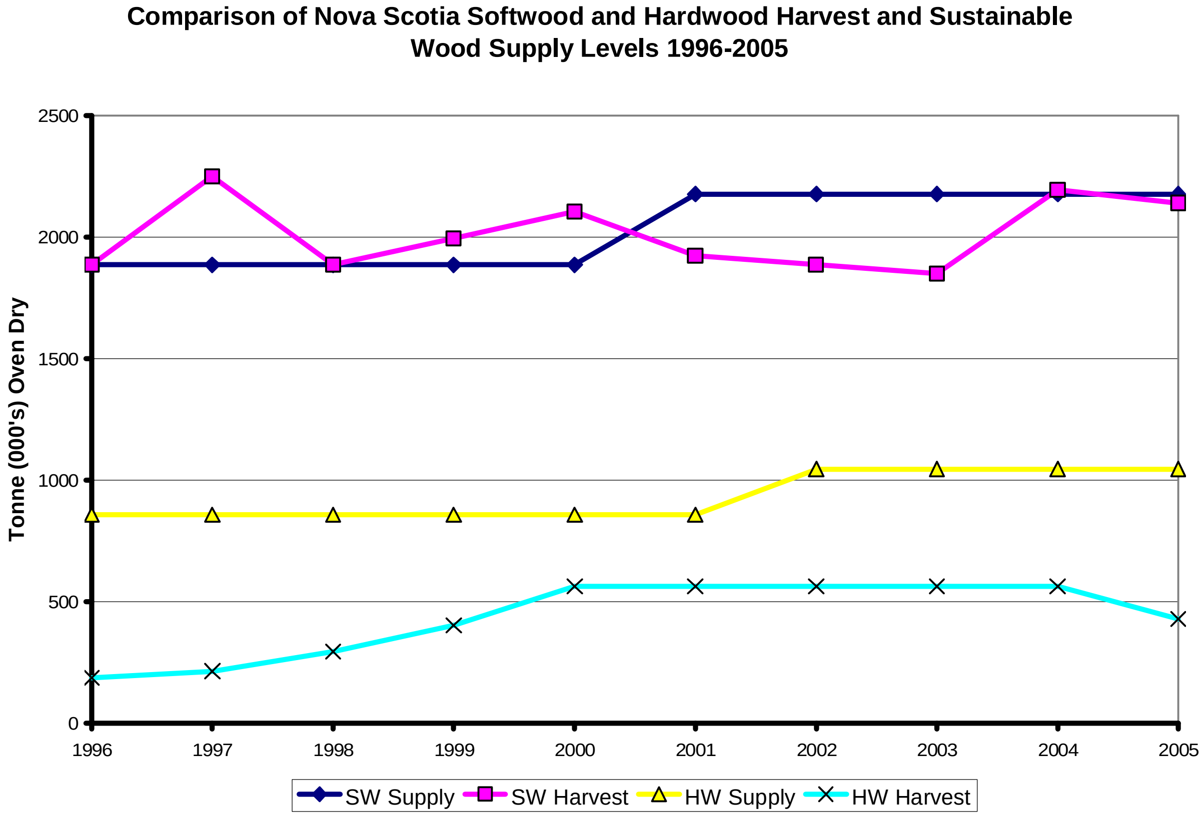
2.2 Biomass Resource

With constantly rising fossil fuel and energy prices, those in the forestry industries seriously consider the opportunities for energy production through the use of locally sourced biomass. The higher heating value (HHV) of local white birch is approximately 9870 Btu/lb on a bone-dry basis. Green wood moisture levels are approximately 50% which effectively reduces the HHV to 4935 Btu/lb. To put this into perspective, the higher heating value of Bunker C oil is approximately 40,364 Btu/L. This means that one tonne of wood chips has the same heating value as 270 L of oil. The efficiency of a wood fired boiler is considerably lower than an oil fired boiler because of the water in the fuel approximately 68% versus 85%. So on a corrected basis, one tonne of wood biomass can produce the equivalent output of 216 L of oil.

Biomass for fuel can be produced with the low value wood that is usually left to rot after conventional roundwood harvesting operations. Pulp and paper companies such as NewPage Port Hawkesbury use mainly softwood for pulp and paper production. There would be opportunities for wood lot operators to harvest the remaining hardwood species to be used as biomass fuel. Tree stems or wood that is defective with forks, crooks, center rot, canker etc could also be included.

The sustainable yields for hardwood and softwood in Nova Scotia were published in the “State of the Forest – Report 1995-2005” by the Nova Scotia Department of Natural Resources. The following Graph indicates sustainable harvests for hardwood and softwood in Nova Scotia.

Figure 1 Nova Scotia Wood Harvest and Supply



From Figure 1 we can see that traditionally all of the sustainable softwood supply of 2.2 x 10^6 tonne/year in Nova Scotia is being harvested. Natural Resources Department personnel indicate that due to the current economic conditions the actual harvest last year was in the order of 1.6 x 10^6 tonne. For conversion purposes the report assumes 0.363 oven dry tonne of softwood per M^3.

We can also note from the data that only around 50% of the sustainable hardwood yield of 1.05 x 10^6 tonne/year is currently being harvested. For conversion purposes the report assumes 0.536 oven dry tonne of hardwood per M^3

2.3 Technologies

The technologies available for wood fired combustion can be divided into three (3) main types: grate combustion, fluidized bed combustion, and gasification.

2.3.1 Grate Combustion

Grate combustion is the traditional technology used for burning solid fuels. Grates are widely used for large power boilers found in pulp and paper mills as well as smaller heating boiler applications. Grates are less tolerant to fuel quality variations than fluidised bed combustion systems. Fuel moisture typically is limited to a maximum of 57% due to the ability of the furnace to maintain stable combustion. Grate technology is relatively simple and is competitive on small scale applications.

With grate systems the wood biomass is blown into the furnace where it is burned on the furnace floor. Combustion air is introduced under the grate and over the grate to promote complete combustion of the fuel and minimize emissions. The hot combustion gases then pass through a heat exchanger to create hot water or steam.

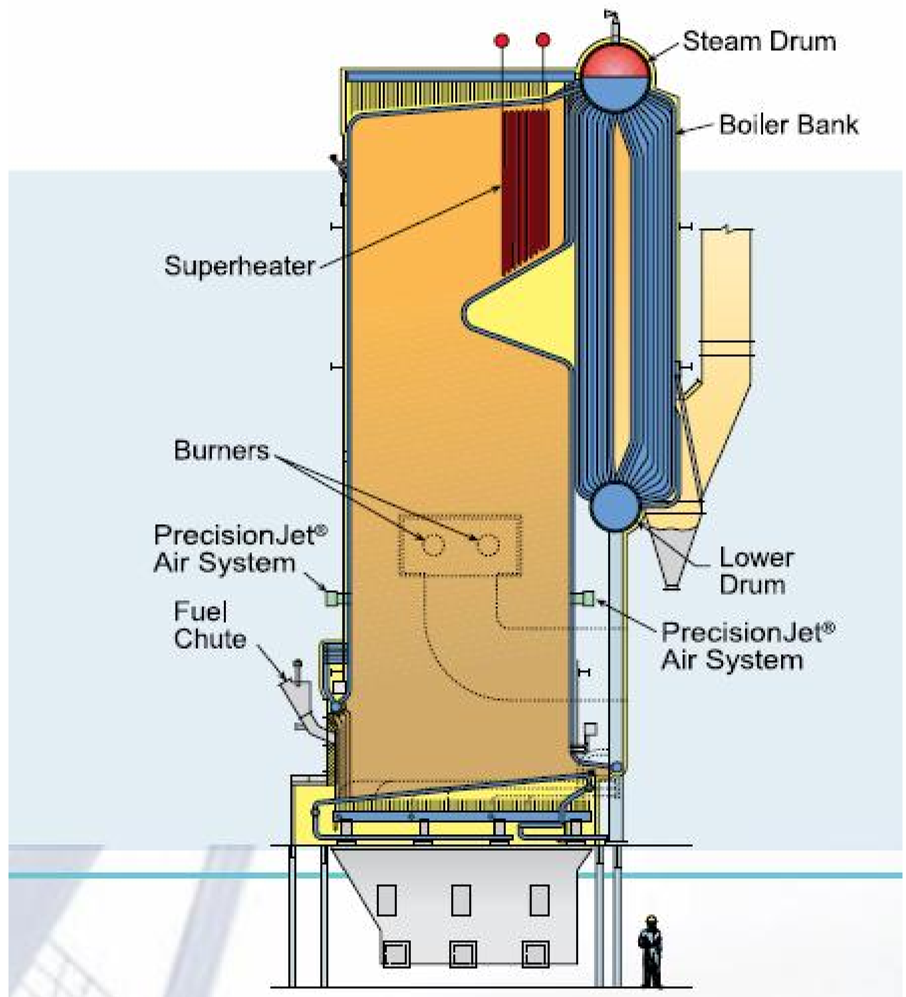


Figure 2 Grate Fired Boiler (Courtesy B&W Canada)

2.3.2 Fluidized Bed Combustion

Fluidized bed combustion technologies have been used for many decades. The wood biomass is thrown into the furnace in a similar method as a grate system also but the gas and particle velocities in the furnace cause the fuel to be burned in suspension. The FBC is more tolerant of varying fuel qualities and can burn mixtures from wet bark to dry sawdust and shavings. As with a grate combustion system, the hot products of combustion leave the furnace section of the boiler and pass through heat exchangers where the products of combustion are cooled and steam is produced.

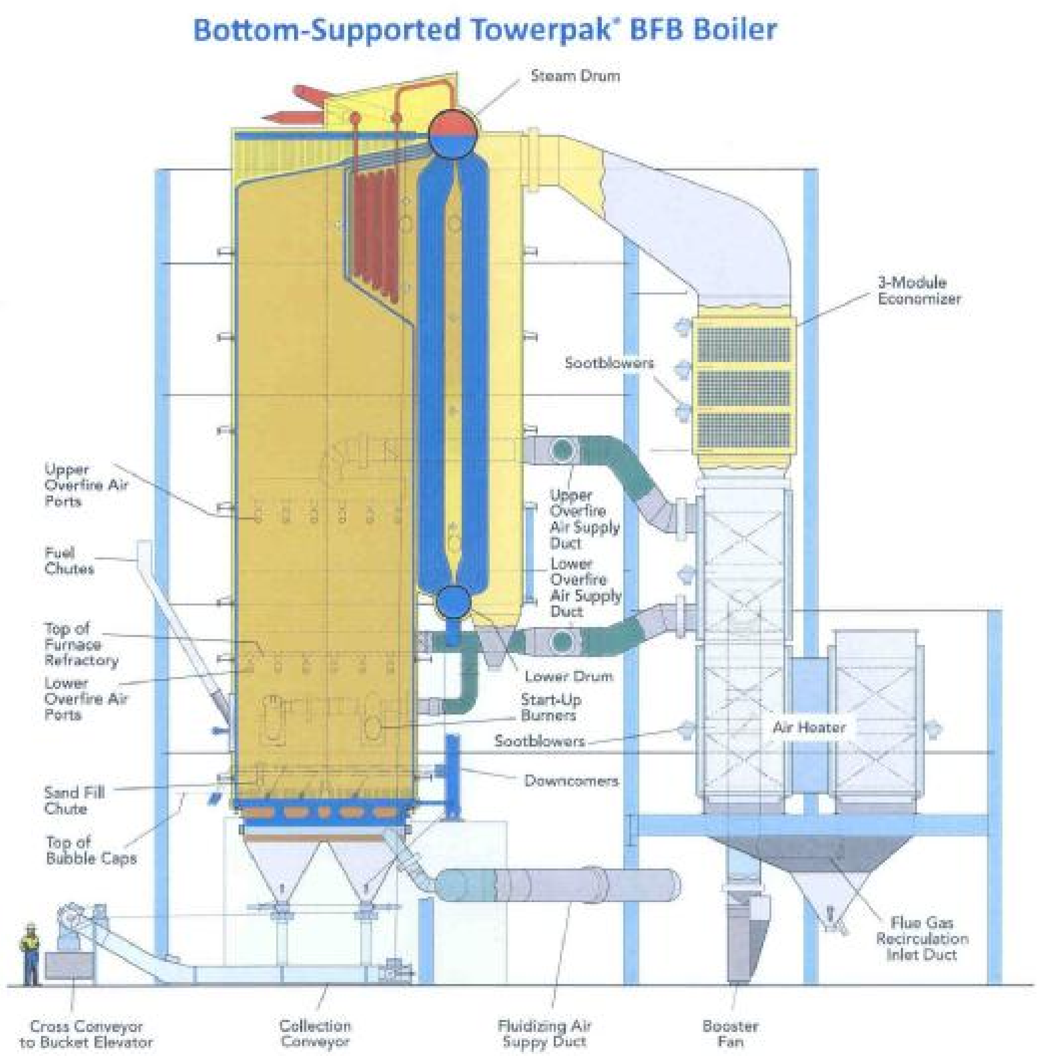


Figure 3 Bubbling Bed Biomass Boiler (Courtesy B&W Canada)

2.3.3 Gasification

Gasification is a process in which biomass is used to produce a gaseous fuel that can then be used as a fuel directly for power production for example in a gas turbine or reciprocating engine.

When biomass is heated with no oxygen or only about one-third the oxygen needed for efficient combustion (amount of oxygen and other conditions determine if biomass gasifies or pyrolyzes), it gasifies to a mixture of carbon monoxide and hydrogen—synthesis gas or syngas.

Combustion is a function of the mixture of oxygen with the hydrocarbon fuel. Gaseous fuels mix with oxygen more easily than liquid fuels, which in turn mix more easily than solid fuels. Syngas therefore inherently burns more efficiently and cleanly than the solid biomass from which it was made. Biomass gasification can thus improve the efficiency of large-scale biomass power facilities such as those for forest industry residues. Like natural gas, syngas can also be burned in gas turbines, a more efficient electrical generation technology than steam boilers, to which solid biomass is limited.

Gasification demonstration plants and pilot plants have been built mainly in Europe, but at this time we would consider this technology as too new and complex and unsuitable for our current application.

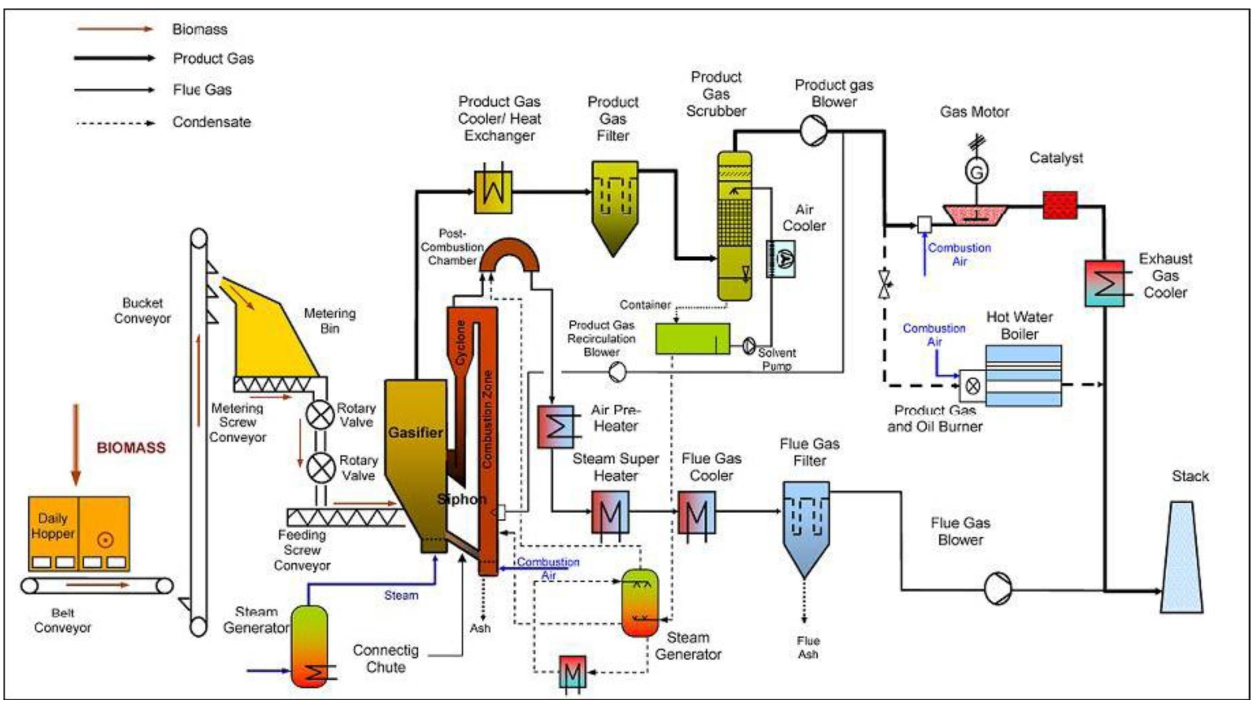


Figure 4 Typical Biomass Gasification Plant – Gussing, Austria

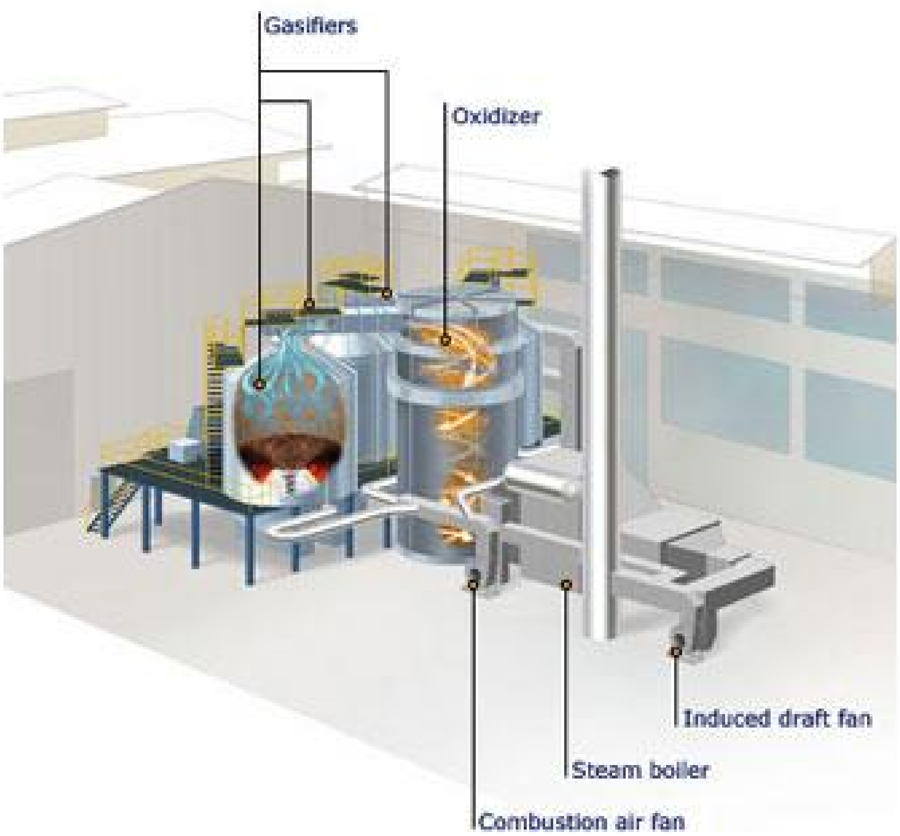


Figure 5 Typical Gasifier – Nexterra – University of South Carolina

3 PRELIMINARY REGULATORY REVIEW

3.1 Environmental Issues

This project would require an environmental assessment under the terms of the Government of Nova Scotia – Environmental Protection Act. A properly prepared and documented assessment application is usually sufficient to satisfy the provincial Department of Environment. The regulations permit the minister to order an assessment for projects not falling under the list of undertakings. Due to the location of the plant in close proximity to a residential area, it is quite likely that an assessment may be required. Potential environmental issues that would need to be addressed would include:

- air emissions - stack gases;
- liquid emissions - boiler blowdown;
- solid waste - cleaners, filters; and
- noise.

Environmental benefits of this plant, which would be emphasized in any permit application, would include net reductions in CO_2 emissions. The emissions reductions would be not only from the reduced load on the oil burning heating boilers at the heating plant but also from the reduced load on the Nova Scotia Power generating system where the fossil fuels are used.

3.1.1 Greenhouse Gas (GHG) Reduction

Emissions from biomass combustion are considered GHG neutral, because the CO_2 emitted from the combustion is equal to the CO_2 captured by the plant as it was growing.

An example of GHG reductions from this biomass cogeneration project is as follows:

GHG Reduction	=	Annual Electrical Production x Emission Intensity Factor
	=	52,553,868 kWh x 0.8 tonne CO2e/MWh x .001 MW/kW
	=	42,043 tonne/yr

GHG Reduction Heating = ST FX heating plant Fuel Consumption x GHG Emission Factor [1]
= 3,300,000 L/year x 3.112 kg CO2e/L
= 10,270 tonne/yr

[1] **Environment Canada, *Canada's Greenhouse Gas Inventory, 1990–2002*; Annex 7: Emission Factors, August 2004**

3.2 Power Connections

The technical requirements of the electrical connections to the Nova Scotia Power grid are detailed in the attachments:

1. *Distribution Generator Interconnection Process*
2. *STANDARD SMALL GENERATOR INTERCONNECTION AND OPERATING AGREEMENT (SSGIA)*
3. */Zonal Loss Factors for Distribution Connected Projects*

3.3 Plant Operations

The operation of the plant will be governed by the Government of Nova Scotia Boiler and Pressure Vessel Regulations. Under the act the plant would be considered a “power plant” because it operates with steam at greater than 15 psig and as such it would require constant attendance by operating staff. The size of the plant dictates that a Chief Power Engineer would be required to have First Class Power Engineer's Certificate. The shift engineers would be required to hold Second Class Power Engineer's Certificate.

4 EVALUATION OF COGENERATION OPTIONS

4.1 Introduction

Cogeneration is the defined as the simultaneous production of two different sources of energy, in this case electrical energy and thermal energy. Cogeneration is a very efficient way to generate energy because of the nature of the thermodynamic cycles involved. If large users of process heat such as greenhouse, hydroponics or district heating are located near the power plant site, the overall plant efficiency can be greatly improved.

There are several heat sources that could be made available. Normally in a power plant, designers try to maximize the electrical output from a steam turbine by having steam exit the steam turbine at a very low pressure and temperature. The steam at about 100°F is then condensed back to water through a condenser heat exchanger to pass through the cycle again. The heat from the condenser is typically lost to atmosphere through cooling towers or to a river or lake. This heat is very low grade (low temperature) and would be useful for greenhouse operations but not for district heating application. For district heating applications we would extract some higher temperature steam from the steam turbine before it exits. This will somewhat reduce the electrical output of the steam turbine.

4.2 Steam Load and Energy Assessments

Figure 6 Monthly Steam Load

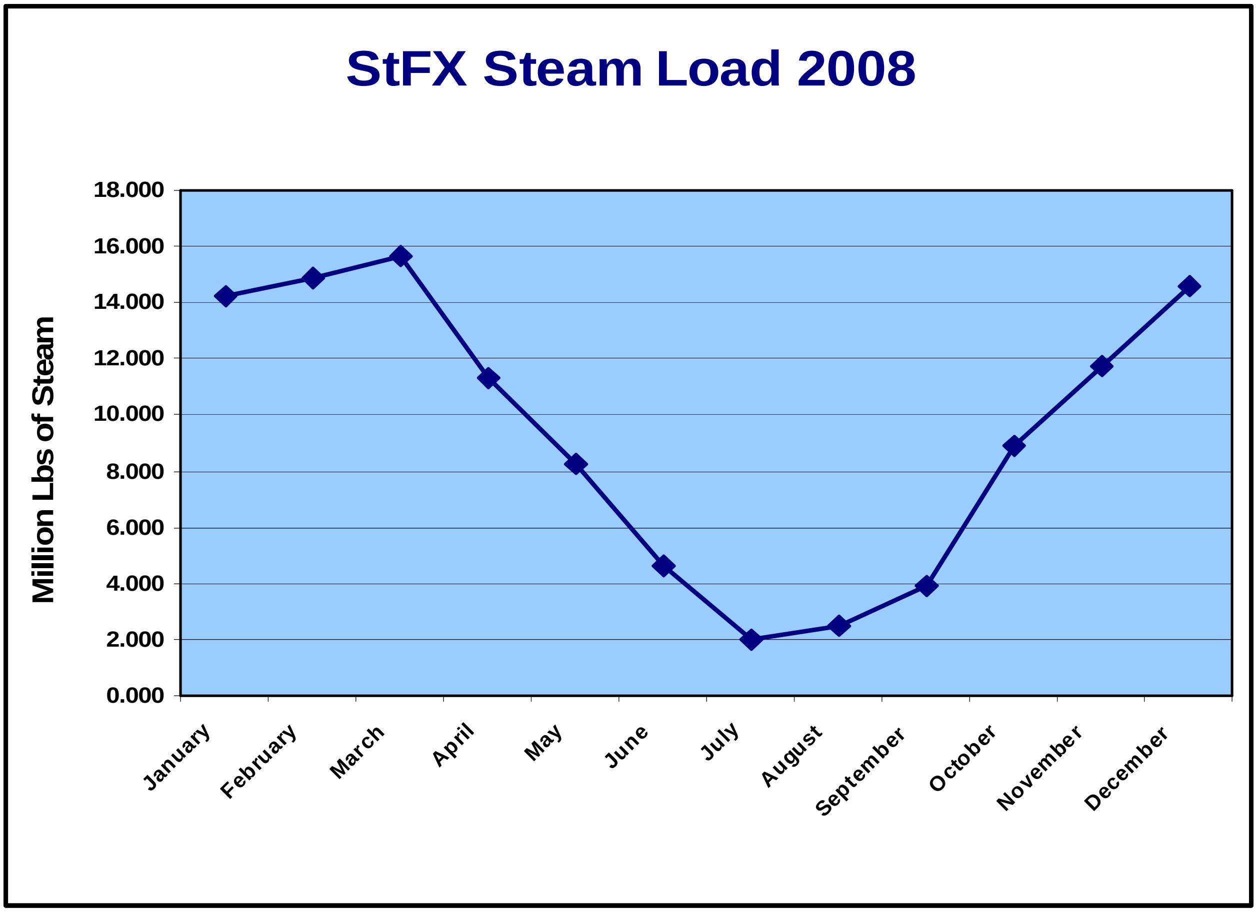
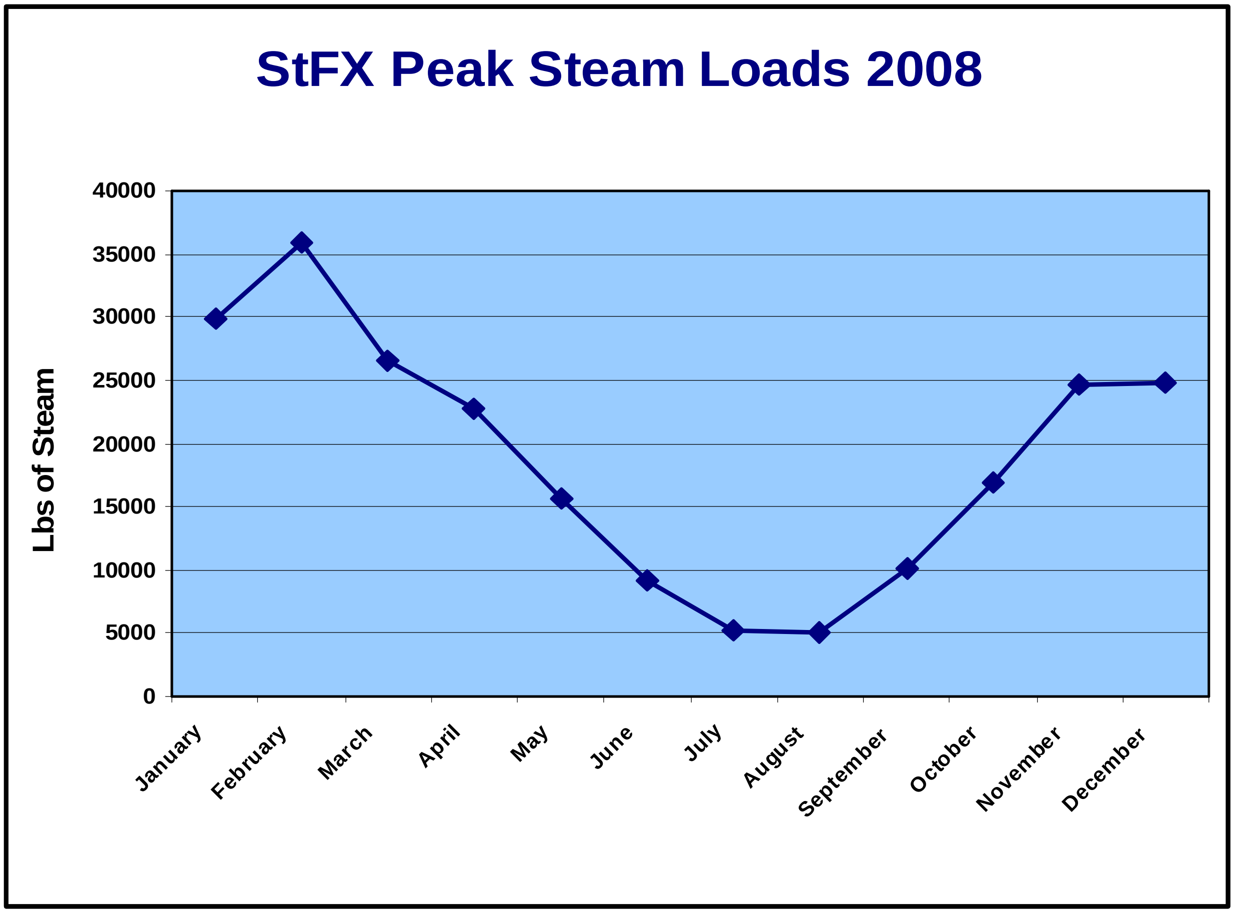


Table 3 Monthly Steam Production

MONTHLY STEAM PRODUCTION LB X 10^6	
January	14.250
February	14.881
March	15.679
April	11.287
May	8.272
June	4.596
July	1.982
August	2.478
September	3.913
October	8.905
November	11.750
December	14.609
Average Hourly	12,943 pph

Figure 7 Peak Steam Loading



4.3 General Criteria for Options

All options chosen for comparative analysis had to meet the following criteria:

- available as new equipment from commercial vendors;
- low emission combustors;
- high overall efficiency; and
- reasonable capital cost.

5 SCOPE OF WORK

5.1 Existing Plant Summary

The existing central heating plant (CHP) is located in the middle of the campus surrounded by university buildings. The CHP consists of one (1) 750 HP watertube, one (1) 600 HP firetube and two (2) 800 HP firetube boilers. These boilers provide 100 psig steam to an underground distribution network to most buildings throughout the campus.

5.2 Cogeneration Plant Summary

The plant will consist of a wood fired boiler bubbling fluidized bed boiler, steam turbine generator, condenser, cooling tower, building, fuel and ash handling systems. The plant would be located on the south side of the TransCanada Highway (TCH) in the vicinity of NS Power's Substation. The steam turbine will be connected to a biomass fired boiler with a capacity of 78,000 lbs/hr of steam at 800 psig 900F. Steam will be supplied to the campus buildings via an underground piping systems. The extraction flow from the steam turbine will be able to accommodate the entire peak heating requirement.

5.3 Turbine/Generator System

The selected option analysis was based on a condensing multistage turbine operating with the following conditions:

- Multi-stage steam turbine
- Dresser-Rand or equal T&T valve
- Controlled extraction opening with non-return valve
- Overspeed trip, solenoid trip, low oil pressure trip
- Woodward DG-505E or equal governor
- Blanket insulation without sheet metal jacket
- Gland condenser and ejector
- Gland seal pressure regulator
- Vacuum breaker
- Condensate drain pump (if turbine is specified with TOP exhaust)
- Vibration probes and transmitters for turbine, gear, and generator
- Bearing RTD's for turbine, gear, and generator
- Vibration probes and RTD's monitored by PLC in generator control panel
- HS and LS couplings
- Reduction gear
- Generator with voltage regulator
- Common baseplate for turbine/gear
- Separate soleplates for generator
- Separate lube console for turbine/gear/generator
- Generator control and switchgear panels

- Main circuit breaker sized for generator output
- Synchronizing equipment
- Protective relays
- Instrumentation
- Suitability for either parallel or solo operation
- PLC for monitoring and control functions
- Neutral grounding resistor

2. Condenser price includes:

- Shell and tube heat exchanger
- Stainless steel tubes
- Hotwell with one minute retention time
- Twin condensate pumps
- Two stage, twin element ejector package sized for 150 PSIG / 450 Deg F steam
- Inter and after condensers cooled by condensate
- Liquid level controls
- Atmospheric relief valve
- Support frame for condenser package
- Condensate piping from hotwell to condensate discharge connection
- Sized for 70 Deg F cooling water from cooling tower, 90 Deg F discharge

Table 4 Steam Turbine Performance

TURBINE DATA		
TURBINE FRAME	R	
NUMBER OF STAGES	10	
INLET VALVES	MULTIPLE	
INLET SIZE/RATING	6” / 900#	
BLEED SIZE/RATING	NONE	
EXTRACTION SIZE/RATING	8” / 300#	
EXHAUST SIZE/RATING	60” RECTANGULAR	
GENERATOR TEMP RISE	80 DEG C	
GENERATOR POWER FACTOR	0.80	
PERFORMANCE DATA	MAX POWER	MAX EXTRACTION
INLET PRESSURE (PSIA)	780	780
INLET TEMPERATURE (DEG F)	900 *	900 *
EXTRACTION PRESSURE (PSIA)	107	107
EXTRACTION ENTHALPY (BTU/LB)	1,303	1,297
EXHAUST PRESSURE (PSIA)	1.0	1.0
EXHAUST ENTHALPY (BTU/LB)	1,049	1,064
INLET STEAM FLOW (LB/HR)	74,730	83,790
EXTRACTION FLOW (LB/HR)	10,000	46,150
EXHAUST FLOW (LB/HR)	64,730	37,640
TURBINE SPEED (RPM)	4,750	4,750
GENERATOR OUTPUT (KW)	8,000	6,265

5.4 Wood Biomass Boiler

One (1) Babcock & Wilcox Bubbling Fluidized Bed Boiler, which includes the following:

- Pressure parts including membrane furnace, boiler bank & drums
- BFB combustor c/w hoppers
- Air pipes and bubble caps
- Air swept spouts c/w balanced draft damper assemblies
- Boiler mountings including water column and gauges
- Economizer and mountings
- Safety valves
- Steam and Main Steam Stop non-return Valve
- Economizer feed, stop/check valve
- Drain valves
- Superheater, attemperator and piping
- Furnace buckstays and casings
- Instrument connections
- Thermocouples
- Air flow measurement devices
- Start-up burner c/w gas ignitor
- Ducts including expansion joints, dampers and drives
- Flues including expansion joints, dampers and drives
- Overfire Air ducts including expansion joints, dampers and drives
- Steam Coil Air Heater
- Mechanical dust collector
- Tubular air heater including casings
- Insulation and lagging
- Forced Draft and Induced Draft fans
- Fluidizing fan and spout air fan
- Flue Gas Recirculation fan
- Flue Gas Recirculation flue c/w expansion joints, dampers and drives
- Sootblowers c/w control panel
- Burner management system
- Precipitator
- Transportation to jobsite
- Installation

5.5 Boiler Performance and Fuel Usage

The assumed fuel for the cogeneration plant is locally harvested white birch. The heating value and ultimate analysis of white birch is estimated from data from Canadian Pulp and Paper Association. The moisture content of green chipped wood can vary from 40% to as high as 50% depending on methods of drying and storage used. For pulp and paper type applications where the bark is removed from the tree and usually stored outside with no weather protection moisture levels approach 60%. For our analysis we will use 50%.

The boiler performance calculations in Table 6 indicate the full load fuel rate required for the plant is 26,550 lb/hr or 290 tonnes/day for 50% moisture wood.

Table 5 Fuel Analysis – White Birch[2]

WHITE BIRCH ANALYSIS	
ASH	1.80%
S	0.00%
H2	6.70%
C	57.40%
N2	0.30%
O2	33.80%
TOTAL	100.00%
High Heating Value @ Bone Dry	9870
High Heating Value @ 50% Moisture	4935

Table 6 Boiler Performance - Full Load 8.0 MW Generator Output Avg Thermal Load

COMPONENT	BLR
Steam Flow MLB/HR	76,730
Outlet Pressure PSIG	800
Outlet Temperature F	900
FW Inlet Pressure PSIG	1000
FW Inlet Temperature F	220
Outlet Enthalpy BTU/LB	1426.1
Inlet Enthalpy BTU/LB	249.1
Component BTU/LB	1,177.0
Component Absorption	90,275
TOTAL OUTPUT MKB/HR	90.275
	50% MOISTURE WOOD
Dry Gas Loss %	7.85
Water From Fuel, AF Loss %	19.34
Moist in Air Loss %	0.20
Unburned Combustible Loss %	2.00
Radiation Loss %	0.33
Unaccounted For MFRS Margin %	1.50
Total Losses %	31.21

[2] Technical Section – Canadian Pulp and Paper Association (CPPA)

Efficiency %	**68.79**
Input in Fuel MKB/HR	131.24
Wet Gas WT MLB/HR	157.08
Total Air to Burn Equip. MLB/HR	130.91
Fuel Rate MLB/HR	26.550

Total annual fuel demand = Hourly fuel rate x average plant load x 8760 h/y x 85% availability

$$= \frac{26550 \text{ lb/hr x } 8760 \text{ h/y x}0.85}{2204.6 \text{ lb/tonne}} = 89{,}672 \text{ tonne*/yr}$$

* tonne = metric tonne (2204.6 lb)

5.6 Mechanical Balance of Plant

The mechanical balance of plant includes all associated mechanical equipment and systems required to produce a finished operational cogeneration plant. The equipment will include: condenser, feedwater pumps, blowdown receivers, deaerators, compressors, control valves, pressure reducing valves.

6 FINANCIAL FEASIBILITY ANALYSIS – COGENERATION

6.1 Introduction

There are several aspects of a project that must be analysed in order to make a sound investment decision.

.1 The project must be technically feasible. In this case the technology is existing and proven.

.2 Funding for the project must exist - there is no point in analysing a project for which funds will run out half way through, since this will prejudice the outcome and render the initial appraisal invalid.

.3 The technical capacity to carry out the project must exist.

.4 Return on Investment. (ROI) is a financial ratio that compares the amount of income derived from an investment with the cost of the investment. ROI is known as a profitability ratio, because it provides information about management's performance in using the resources of the small business to generate income. ROI and other financial ratios can provide small business owners and managers with a valuable tool to measure their progress against predetermined internal goals, a certain competitor, or the overall industry. ROI is also used by bankers, investors, and business analysts to assess a company's use of resources and financial strength. The general formula for computing ROI is income/invested capital. ROI can be computed by dividing net income by owners' equity. This measure indicates how well the overall company is utilizing its equity investment. Calculated in this way, ROI provides a good indicator of profitability that can be compared against competitors or an industry average.

.5 Threshold values - In economics, as in other disciplines, it is often useful for the decision-maker to be able to define threshold values or cut-off points, above which a certain decision is appropriate and below which another becomes valid. In economic and financial decision-making these are often referred to as break-even points. They define the point at which a project "breaks even", meaning that above this point the benefits exceed the costs; below this point the costs exceed the benefits. In the same way that the cut-off point for a diagnostic test can be adjusted to make it either more specific or more sensitive, in economics, the cut-off discount rate chosen can make it possible to give different weights to long-term benefits as against current costs.

.6 The inherent risks associated with this type of project are construction cost overruns, fuel cost and availability, labour cost and availability and interest rate fluctuations.

6.2 Cost Estimate

The following is the capital cost estimate for the 8 MW cogeneration plant. The breakdown of costs below includes budget pricing on major equipment such as the boiler, steam turbine and condenser. All prices are in Canadian dollars, taxes not included.

Table 7 Capital Cost Estimate

8 MW Cogeneration Plant Capital Cost Summary	
Boiler – B&W Bubbling Bed	$ 12,720,000
Steam Turbine Generator	$4,929,000
Condenser	$ 1,060,000
Cooling Tower	$ 424,000
Water Treatment	$ 398,000
Boiler Feed Pumps	$212,000
Deaerator	$127,000
Piping Tie-in to existing Distribution	$1,908,000
Mechanical BOP	$ 4,240,000
Electrical	$ 1,590,000
Instrumentation & Control	$ 954,000
Civil Works and Buildings	2,120,000
Subtotal	**$30,682,000**
Engineering and Project Management	$3,068,000
Contingency	$3,068,000
TOTAL	**$36,818,000**

6.3 Financial Analysis Results

The financial analysis indicates that at current and projected fuel and electricity costs a biomass fired cogeneration plant is a marginal investment.

The assumptions for the financial analysis are:

- Plant Life – 20 Years;
- Capital costs do not include cost of land

Table 8 Financial Summary

FINANCIAL SUMMARY		
Annual Electricity Exported	52.552	10^6 kWh
Annual Steam Exported	95,309	10^6 BTU
Annual Fuel Imported	89,672	Tonne (Green)
Total Investment	36,818	k CDN
Electricity Sale Price	0.213	$/kWh
Fuel Price	40	$/Tonne
Thermal Sale Price	16.00	$/ MMBtu
Inflation Rate	1.8	%
Debt/Equity	60/40	%
Interest Rate on Debt	9.5	%
Plant Life	20	years
Return on Equity (ROE)	13	%

As can be seen from the financial summary, from the cogeneration option could be feasible if electricity could be sold at 0.213$/kwh.

6.4 Sensitivity Analysis

The financial model was run by varying the fuel costs, electric sales cost and capital costs to see what impacts they had on Return on Equity.

Figure 8 Sensitivity Analysis ROE vs Delivered Fuel Price

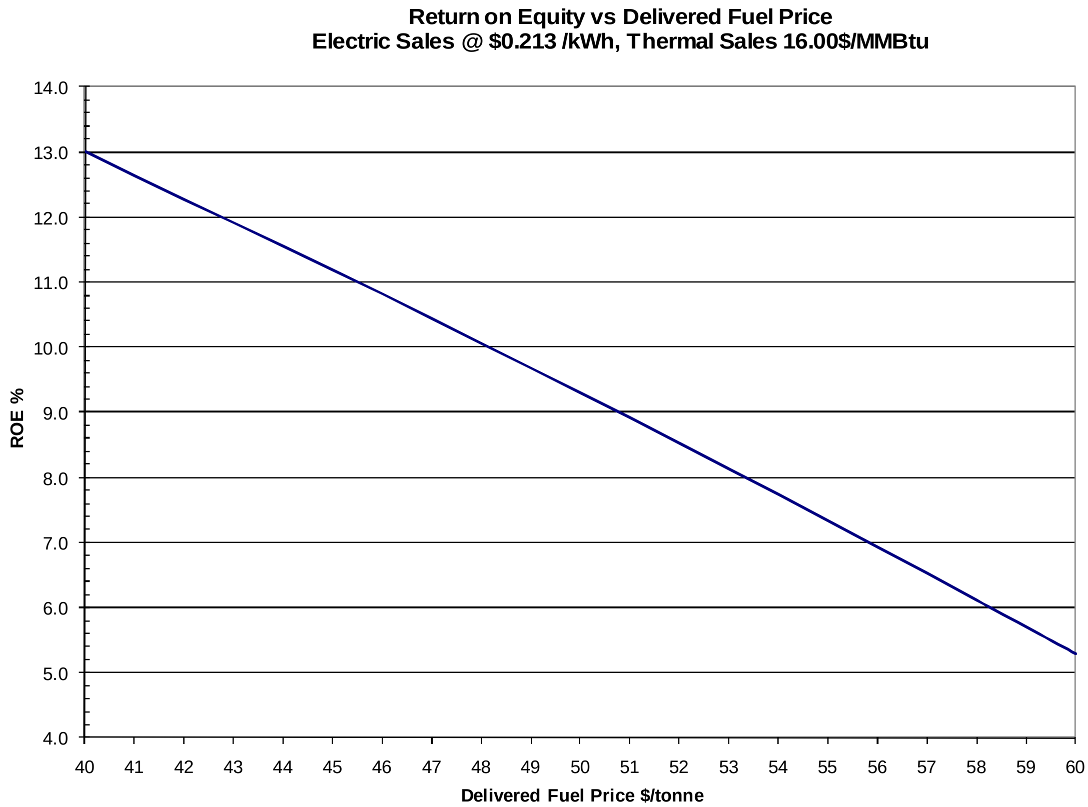
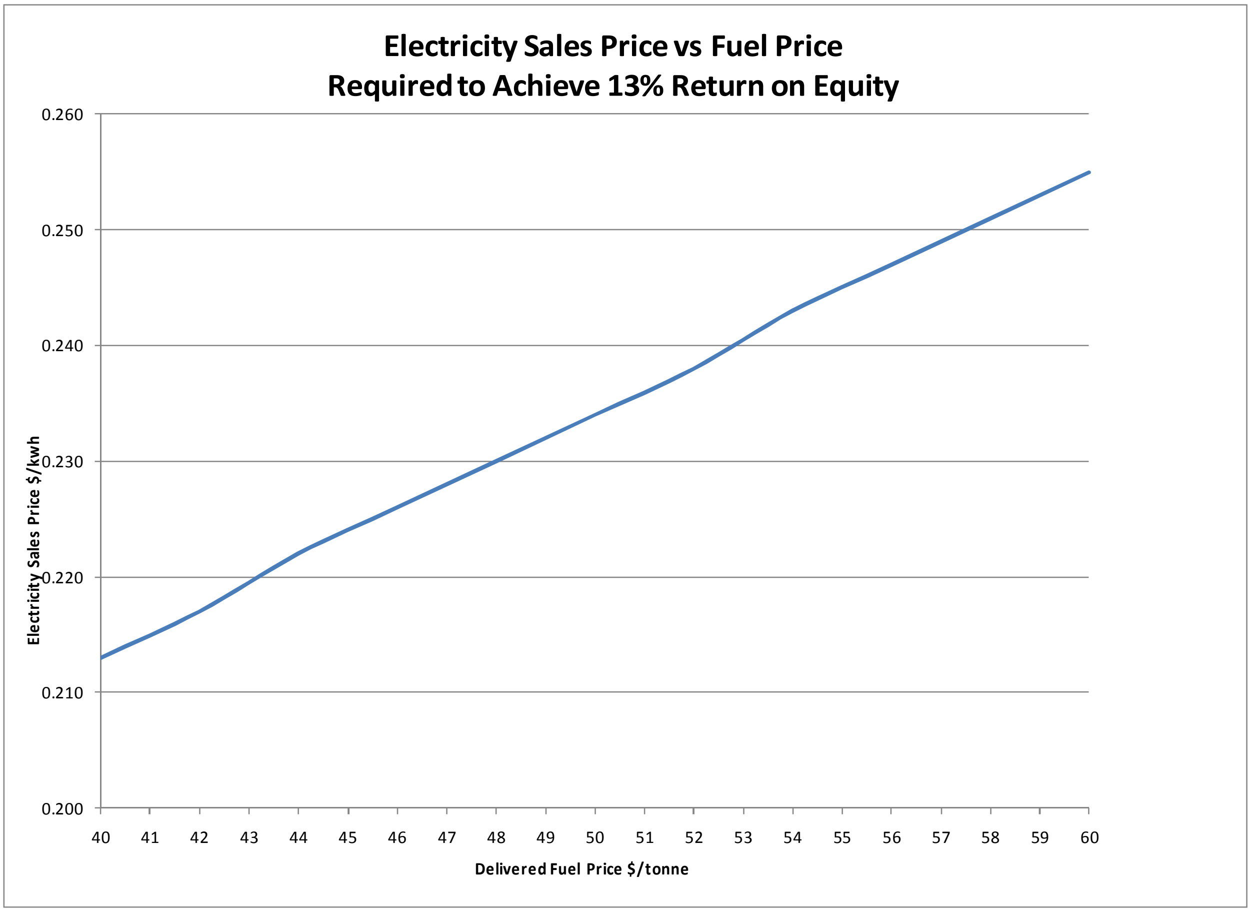


Figure 9 Sensitivity Analysis – Electricity Sales Price vs. Fuel Price for 13% ROE



7 CONCLUSIONS AND RECOMMENDATIONS

Biomass cogeneration is a well established technology that is widely used in industrial applications such as pulp and paper mills and sawmills where an abundant and cheap source of biomass is available as a by-product of mill operations. Other areas where biomass cogeneration is sometimes feasible are remote areas that have adequate fibre resources and expensive imported fuel. The benefits of using locally harvested wood biomass for electrical and thermal energy production are numerous.

- The local economy benefits by providing jobs in the construction, operation and maintenance of the biomass cogeneration systems. The money stays in the local economy. We would expect the plant to employ as a minimum 18 to 20 people.
- Will provide opportunities in the forestry sector for harvesting, processing and transporting the biomass. We would expect these activities to employ up to 40 people on a seasonal basis.
- Local energy costs are less dependent on world prices for fossil fuels.

This report looks at the technical concepts of a cogeneration plant as well as a preliminary business model.

After reviewing the economics of this project it was determined that the project could be feasible at 13 % Return on Equity if electricity can be sold to the grid at a price of 0.213$/kwh along with thermal energy sales at 16.00$/mmbtu. A further detailed study will be required to refine capital and operating costs.

babcock & wilcox canada ltd.
» 581 coronation boulevard » cambridge, on n1r 5v3 canada
» phone 519.621.2130 » fax 519.622.7352 » www.babcock.com

March 19, 2009

CBCL Ltd.
1489 Hollis Street,
Halifax, Nova Scotia
B3J 2R7

Attention: **Mr. Darren Hartlen**
Senior Mechanical Engineer

Subject: **Indicative Proposal**
Biomass Fired TowerPak® Boiler
Nova Scotia Power Inc.

B&W Ref: **CM008517R1**

Babcock & Wilcox Canada Ltd. (B&W) is pleased to provide the following indicative proposal for a bio-mass fired power boiler for your Nova Scotia Power Inc. in Antigonish, Nova Scotia. We are offering a bottom supported 2-drum TowerPak design utilizing a BFB combustor. We have attached our BFB brochure that comparison between the BFB and stoker-fired technologies.

DESIGN PARAMETERS

Fuel type:	Hog
HHV of wood fuel:	8,740 BTU/lb Dry
Maximum moisture content:	57%
Steam flow:	88,000 pph
Operating pressure:	825 psig
Operating temperature:	900 ^{o} F
Feedwater temperature:	220 ^{o}F

SCOPE OF SUPPLY BY B&W

The scope of supply is as follows for either boiler unless noted:

- Pressure parts including membrane furnace, boiler bank & drums
- BFB combustor c/w hoppers
- Air pipes and bubble caps
- Air swept spouts c/w balanced draft damper assemblies
- Boiler mountings including water column and gauges
- Economizer and mountings
- Safety valves
- Steam and MSSNR valves
- Economizer feed, stop/check valve
- Drain valves
- Superheater, attemperator and piping
- Furnace buckstays and casings
- Instrument connections
- Thermocouples

- Air flow measurement devices
- BFB start-up burner c/w gas ignitor
- Ducts including expansion joints, dampers and drives
- Flues including expansion joints, dampers and drives
- OFA ducts including expansion joints, dampers and drives
- SCAH
- Mechanical dust collector
- Tubular air heater including casings
- Insulation and lagging
- FD and ID fans
- Fluidizing fan
- Spout air fan
- FGR fan
- FGR flue c/w expansion joints, dampers and drives
- Sootblowers c/w control panel
- Burner management system
- Precipitator
- Transportation to jobsite
- Installation

SCOPE OF SUPPLY BY OTHERS

The following is intended as a guide only and does not necessarily cover all items of supply or services that may be required to be supplied by others.

- Fuel delivery system upstream of the wind swept spouts
- Platforms, walkways and support for auxiliary equipment
- Piping to the battery limits
- Civil works
- DCS
- Fan motors
- I&C and electrical
- Stack
- Boil-out and chemical cleaning chemicals
- Start-up, commissioning and testing (B&W tech. advisor on per diem basis)
- Site support services- i.e. temp power, air, water, washrooms, etc.

TERMINAL POINTS

- Air and flue gas from the inlet of the FD fan to the outlet of the ID fan
- Fuel at the inlet to the wind swept spouts
- Bottom ash at the exit of the hopper flanges
- Flyash at the hopper flange outlets
- Gas burner at the inlet to the fuel train
- Piping connections at all ASME Section 1 valve connections

SCHEDULE

The following schedule milestones are provided to assist in the planning process for this project.

Milestone	Months from Award
Award	0
Start Manufacturing	6
Start of Erection	12
Hydro	20

The boiler would be erected on a straight time basis, i.e. eight (8) hours per day, five (5) days per week based on summer construction.

PRICE

The estimated price for the supply, delivery and installation of the above referenced scope is:

Twelve Million Dollars ....$12,000,000.

The above price is an estimated price only and is not given by Babcock & Wilcox Canada as an offer, nor as a term of contract, nor as an understanding that the estimated prices shall be final prices. An offer to sell is made by proposal only which shall include Babcock & Wilcox terms of sale.

BASIS OF BID

- Price in present day Canadian dollars.
- All applicable taxes would be extra.
- B&W standard quality and manufacturing practices and procedures.
- B&W standard commercial terms and conditions.
- Standard lead-times.
- Straight time shop and erection labour.
- Supply/Install ratio is 50/50.
- Accuracy of the estimate: +26%, -15%.

If you have any questions, please do not hesitate to call me.

Yours truly,

Babcock & Wilcox Canada

Len Bickerton

Len Bickerton
Proposal Manager

cc: P. Cox, Thermal Power Engineering
J. Graham, Thermal Power Engineering
K. Rivers, Proposal Manager, Thermal Power

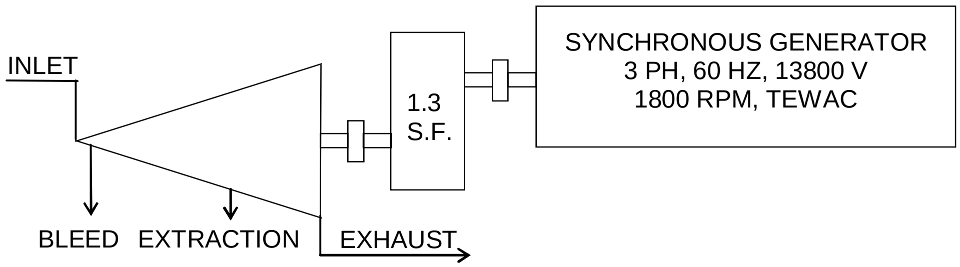
Attachment:
B&W BFB Brochure

DRESSER-RAND
Steam Turbine Business Unit

3800 West Avenue
Burlington, Iowa 52601
Phone: (319) 753-5431
Fax: (319) 752-1616

STEAM TURBINE-GENERATOR BUDGET PROPOSAL

TO MC RAE ENGINEERING, TORONTO, ONTARIO ATTN: DAVID DUTHIE
ADDRESS: DATE: MARCH 13, 2009
SUBJECT: CBCL LIMITED
SHEET: 1 of 2 INCLUDING THIS SHEET
SIGNED: JOHN GRAHAM jgraham@dresser-rand.com D-R REF : G27276

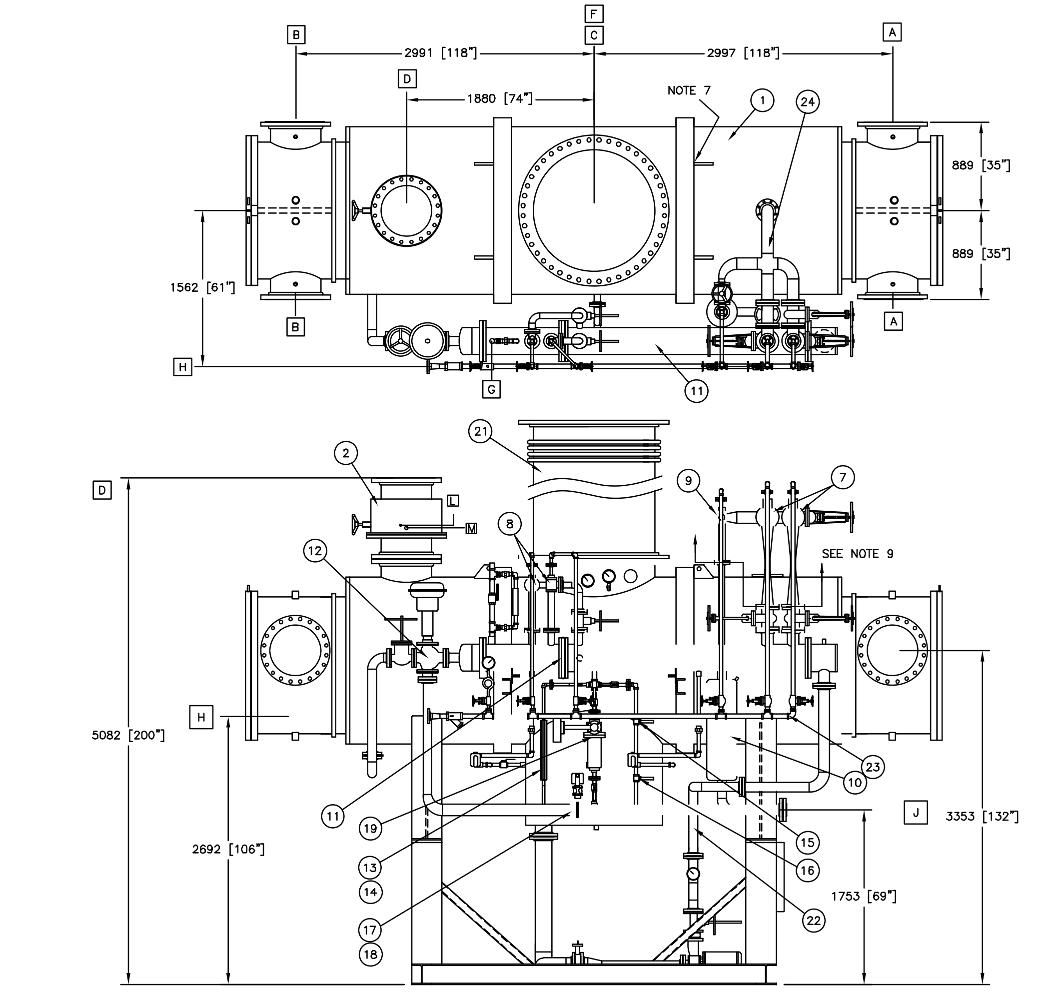


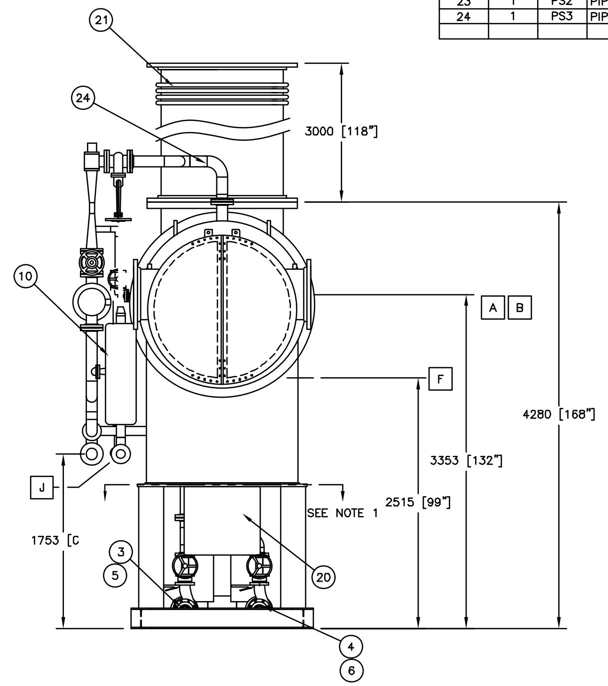
TURBINE DATA		
TURBINE FRAME	R	
NUMBER OF STAGES	10	
INLET VALVES	MULTIPLE	
INLET SIZE/RATING	6" / 900#	
BLEED SIZE/RATING	NONE	
EXTRACTION SIZE/RATING	8" / 300#	
EXHAUST SIZE/RATING	60" RECTANGULAR	
GENERATOR TEMP RISE	80 DEG C	
GENERATOR POWER FACTOR	0.80	
PERFORMANCE DATA	MAX POWER	MAX EXTRACTION
INLET PRESSURE (PSIA)	780	780
INLET TEMPERATURE (DEG F)	900 *	900 *
EXTRACTION PRESSURE (PSIA)	107	107
EXTRACTION ENTHALPY (BTU/LB)	1,303	1,297
EXHAUST PRESSURE (PSIA)	1.0	1.0
EXHAUST ENTHALPY (BTU/LB)	1,049	1,064
INLET STEAM FLOW (LB/HR)	74,730	83,790
EXTRACTION FLOW (LB/HR)	10,000	46,150
EXHAUST FLOW (LB/HR)	64,730	37,640
TURBINE SPEED (RPM)	4,750	4,750
GENERATOR OUTPUT (KW)	8,000	6,265
COMMERCIAL DATA		
SHIPMENT (WEEKS)	56	
TURBINE GENERATOR PRICE (USD)	$ 4,650,000	
ADD FOR:		
CONDENSER PACKAGE	$ 1,000,000	

*** THE INQUIRY CALLED FOR 919 DEG F INLET TEMPERATURE. MAXIMUM RATED INLET TEMPERATURE FOR D-R BURLINGTON TURBINES IS 900 DEG F.**

1. Turbine generator price includes:
   - Multi-stage steam turbine
   - Dresser-Rand or equal T&T valve
   - Controlled extraction opening with non-return valve
   - Overspeed trip, solenoid trip, low oil pressure trip
   - Woodward DG-505E or equal governor
   - Blanket insulation without sheet metal jacket
   - Gland condenser and ejector
   - Gland seal pressure regulator
   - Vacuum breaker
   - Condensate drain pump (if turbine is specified with TOP exhaust)
   - Vibration probes and transmitters for turbine, gear, and generator
   - Bearing RTD's for turbine, gear, and generator
   - Vibration probes and RTD's monitored by PLC in generator control panel
   - HS and LS couplings
   - Reduction gear
   - Generator with voltage regulator
   - Common baseplate for turbine/gear
   - Separate soleplates for generator
   - Separate lube console for turbine/gear/generator
   - Generator control and switchgear panels
   - Main circuit breaker sized for generator output
   - Synchronizing equipment
   - Protective relays
   - Instrumentation
   - Suitability for either parallel or solo operation
   - PLC for monitoring and control functions
   - Neutral grounding resistor

2. Condenser price includes:
   - Shell and tube heat exchanger
   - Stainless steel tubes
   - Hotwell with one minute retention time
   - Twin condensate pumps
   - Two stage, twin element ejector package sized for 150 PSIG / 450 Deg F steam
   - Inter and after condensers cooled by condensate
   - Liquid level controls
   - Atmospheric relief valve
   - Support frame for condenser package
   - Condensate piping from hotwell to condensate discharge connection
   - Sized for 70 Deg F cooling water from cooling tower, 90 Deg F discharge





NOZZLE SCHEDULE

NOZZLE	DESCRIPTION	QTY	SIZE	RATING	TYPE
A	COOLING WATER INLET	2	20"	150#	RF
B	COOLING WATER OUTLET	2	20"	150#	RF
C	STEAM INLET	1	48"	LW *	FF
D	ATMOSPHERIC RELIEF VALVE VENT	1	20"	150#	RF
E	CONDENSATE DISCHARGE	1	4"	150#	RFSO
F	INITIAL FILL	1	1"	--	NPT
G	AIR DISCHARGE	1	1 1/2"	--	NPT
H	MOTIVE STEAM	1	2"	150#	RF
J	HOGGING EJECTOR DISCHARGE	1	3"	150#	RF
K	INSTRUMENT AIR (ON LC1)	1	1/4"	--	NPT
L	SEAL WATER SUPPLY	1	1/4"	--	NPT
M	SEAL WATER OVERFLOW	1	3/4"	--	NPT

ACCESSORIES LIST

MARK	QTY	TAG	DESCRIPTION
1	1	–	MAIN CONDENSER
2	1	ARV	ATMOSPHERIC RELIEF VALVE
3	1	P1	CONDENSATE PUMP
4	1	P2	CONDENSATE PUMP
5	1	M1	PUMP MOTOR
6	1	M2	PUMP MOTOR
7	2	EJ1 EJ2	FIRST STAGE EJECTORS
8	2	EJ3 EJ4	SECOND STAGE EJECTORS
9	1	EJ5	HOGGING EJECTOR
10	1	S1	SILENCER FOR HOGGING EJECTOR
11	1	HX	INTER-AFTER CONDENSER
12	1	CV1	DISCHARGE/RECIRC CONTROL VALVE
13	1	LT1	LEVEL TRANSMITTER
14	1	LI	LEVEL INDICATOR
15	1	LSH	LEVEL SWITCH HIGH
16	1	LSL	LEVEL SWITCH LOW
17	1	FIT1	FLOW TRANSMITTER
18	1	FE1	FLOW ELEMENT
19	1	LC1	PNEUMATIC LEVEL CONTROLLER
20	1	CP1	CONTROL PANEL
21	1	EXJ	STEAM DUCT W/EXPANSION JOINT
22	1	PS1	PIPE SPOOL (SEE NOTE 1)
23	1	PS2	PIPE SPOOL (SEE NOTE 9)
24	1	PS3	PIPE SPOOL (SEE NOTE 9)

NOTES

1. BREAK POINT FOR SHIPPING. – BASE FRAME WITH PUMPS TO BE SHIPPED SEPARATE. PIPE SPOOL PS1 (CONNECTING DISCHARGE OF PUMPS TO INTER/AFTER CONDENSER) TO SHIP LOOSE. ATMOSPHERIC RELIEF VALVE TO BE SHIPPED LOOSE.
2. CUSTOMER PIPING MUST BE DESIGNED TO INCURE NO STRAIN ON CONDENSER.
3. FLANGE BOLT HOLES TO STRADDLE CENTER LINES.
4. CONNECTION LOCATION TOLERANCE IS ±13 MM [1/2"].
5. CONDENSER MUST BE OPERATED IN ACCORDANCE WITH INSTRUCTIONS GIVEN IN THE O&M MANUAL.
6. PREP EXTERIOR SURFACE PER SSPC SP-3 AND PAINT WITH GRAY ENAMEL, 1 MIL MINIMUM THICKNESS.
7. FOUR LIFTING LUGS ARE PROVIDED ON CONDENSER SHELL. WHEN LIFTING, A SPREADER FRAME MUST BE USED TO AVOID COLLAPSING LOADS ON THE CONDENSER AND EQUIPMENT.
8.
9. ITEMS 7, 9, 10, 21, 23, 24 WILL BE SHIPPED LOOSE FOR INSTALLATION AT SITE BY OTHERS.

PROJECT: KOREA ZINC
CUSTOMER: DRESSER-RAND
PROJECT NO.: T5764

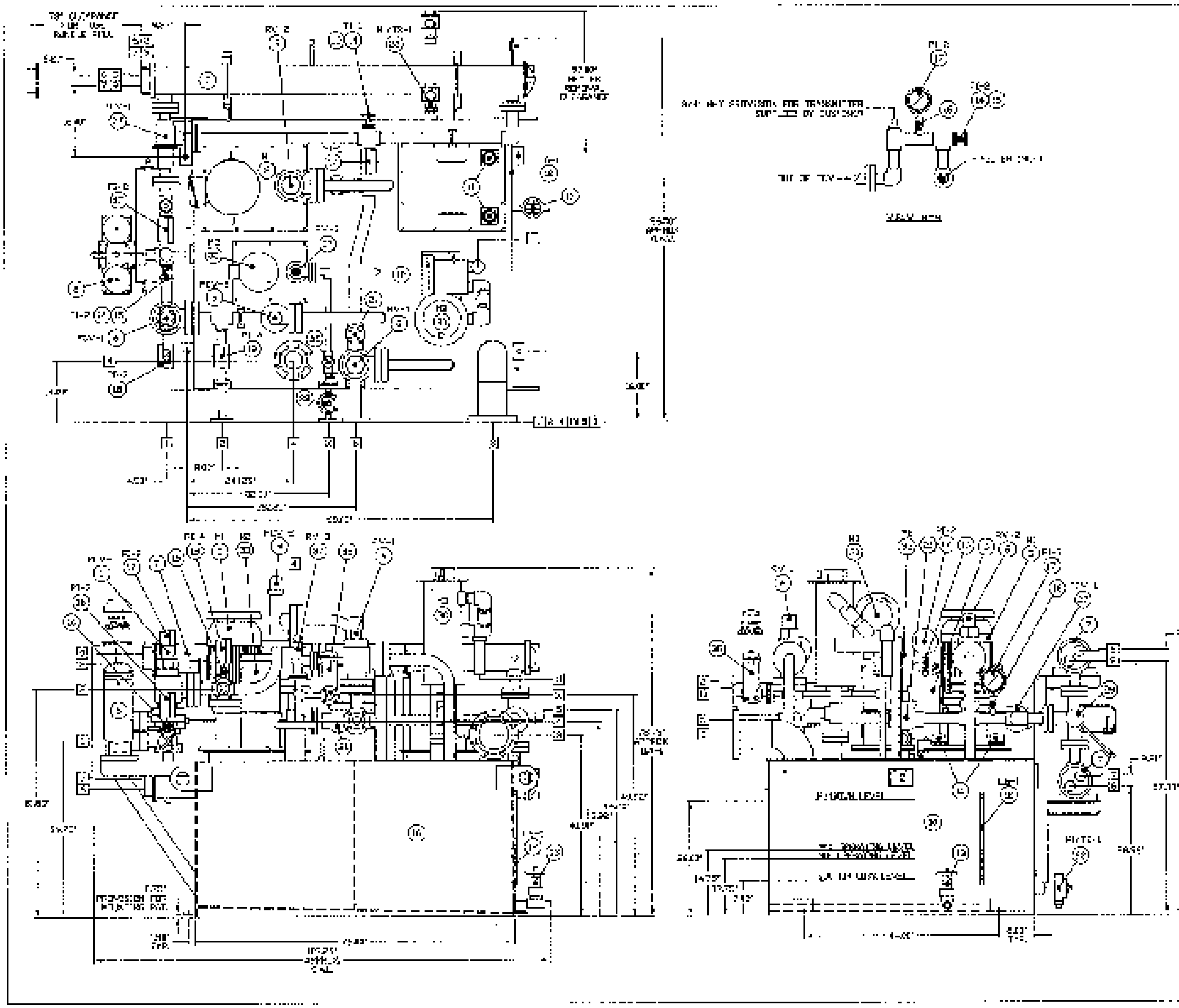
REV	DESCRIPTION	DATE:	BY:	CHK'D
0	ORIGINAL ISSUE	8/2/06	AST	MG

AMBASSADOR HEAT TRANSFER CO.
P.O. BOX 42344
CINCINNATI, OHIO 45242

TITLE: STEAM SURFACE CONDENSER PACKAGE GENERAL ARRANGEMENT

SCALE: 1=24

DRAWING NUMBER: 061044-GA



REV.	REVISIONS	DATE
1	[illegible]	[illegible]
2	REVISED HEAT EXCHANGER [illegible] CONNECTION & ELEVATION	[illegible]
3	[illegible] SYSTEMS	[illegible]
4	MOVED EMERGENCY PUMP [illegible]	[illegible]
5	AS BUILT	[illegible]

NOTES:

1. SEE DRAWING No. [illegible] FOR SYSTEM BILL OF MATERIALS. SEE DRAWING No. [illegible] FOR SYSTEM ELECTRICAL LAYOUT. SEE DRAWING No. [illegible] FOR SYSTEM PIPING & INSTRUMENTATION DIAGRAM.
2. DO NOT ATTEMPT TO [illegible] [illegible] CERTIFIED BY LUBE POWER, INC.
3. [illegible] TO [illegible] LEVEL.
4. RESERVOIR INITIAL FILL [illegible] GALLONS.

CUSTOMER CONNECTION LIST

LEGEND	SIZE / FUNCTION
1	[illegible]
2	[illegible] 150# FLANGE / [illegible]
3	80' S.F. 150# FLANGE / LUBE OIL RETURN
4	[illegible] 150# FLANGE / [illegible] PUMP SUCTION
5	[illegible] 150# FLANGE / [illegible] PUMP [illegible]
6	[illegible] / COOLING WATER SUPPLY
7	20' FNPT / COOLING WATER RETURN
8	20' FNPT / COOLING WATER SUPPLY
9	20' FNPT / COOLING WATER RETURN
10	[illegible] FLANGE / EMERGENCY [illegible]
11	[illegible]

LUBE-POWER, INC.

SYSTEM GENERAL ASSEMBLY

Earnings Statement

1	Revenue			
	Gross Electrical Output		7,999	kw
	Net Electrical Power output kw		7,058	kw
	Hours/year operation		7,446	h
	Electrical energy production		52,553,868	kWh
	Rate		0.2130	$/KWHR
	Annual escalation		1.80%	
	Secondary electrical energy production			
	Rate			
	Annual escalation			
	Average Annual Steam Output	MMB	12.80	
	Thermal energy production		95,309	
	Rate $/MMBTU		16.0000	
	Annual escalation		1.80%	
	Carbon Credits $/tonne		0	$/tonne
	NSP Intensity Factor		0.80	tCO2e/mwhr
	Capacity Factor		0.00	$/mwhr
	Initial availability of plant on an annual basis		85.0%	
	Annual degradation of power available		0.200%	

6.1.3	**Annual O&M Cost Estimate**			13.06%
	(All costs in 2011 CAN$)			
	Operating and Maintenance - Fixed			
	Manager		125,000	
	Admin. Personnel		40,000	
	Maintenance Contract		200,000	
	Operators13 total @85K		1,105,000	
	Consultants		50,000	
	Insurance		348,000	
	General Supplies		50,000	
	Miscellaneous		50,000	
	Fuel		0	
	burn rate LB/HR	26,550		
	PRICE $/TONNE	40		
	Fuel Heating Value btu/lb			
	Tonnes/year	89,672.2		
	Total Fuel		3,586,887.4	
	Total costs - 1st year		5,555,000	
	Annual escalation		2.0%	

3	Accounts receivable	
	Collection of revenue as follows:	
	Current	0.0%
	30 days	100.0%
	60 days	0.0%
	Provision for Bad debts	0.0%
		100.0%

	Total annual revenue - amount in A/R at end of year			8.3%
		50		
4	Capital Costs			
	Non depreciable			0
	Depreciable			36,818,040
	Total			36,818,040
	Depreciation Rates - Straight line - years			30.0
	Capital Additions	Year		Amount
	-Depreciation on capital additions - Straight	7		0
	line	14		0
4	Financing of Capital Costs			
	Debt		60.0%	22,090,824
	Equity / Internal		40.0%	14,727,216
	Minimal rate of return on equity		10.0%	
	(Discount rate)			
	Financing of Capital Additions			**Loan #2**
	Debt		50.0%	0
	Equity		50.0%	0
	Terms of Debt			
			Loan #1	**Loan #2**
	Interest Rate		9.50%	9.50%
	Term - years debt to be paid		20	0
	Paid in # of periods per year		4	4
		Pv		
	Future value of debt at end of term	Fv	0	0
	Payments at beginning (1) or end of period	Type	0	0
5	Bank Operating Loan			
	Interest on bank debt			9.5%
6	Accounts payable			
	Payment of expenses under the following terms			
	Current			0.0%
	30 days			100.0%
	60 days			0.0%
				100.0%
	Total annual expenses, amount in A/R at end of year			8.3%
7	Corporate tax rate			40.0%
	Capital Cost Allowance Rate			40.0%
	Payable in			180

Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Revenue																				
Electrical energy production	52,553,868	52,553,868	52,553,868	52,553,868	52,553,868	52,553,868	52,553,868	52,553,868	52,553,868	52,553,868	52,553,868	52,553,868	52,553,868	52,553,868	52,553,868	52,553,868	52,553,868	52,553,868	52,553,868	52,553,868
Rate	0.2130	0.2168	0.2207	0.2247	0.2288	0.2329	0.2371	0.2413	0.2457	0.2501	0.2546	0.2592	0.2638	0.2686	0.2734	0.2784	0.2834	0.2885	0.2937	0.2989
Total	11,193,974	11,395,465	11,600,584	11,809,394	12,021,963	12,238,359	12,458,649	12,682,905	12,911,197	13,143,599	13,380,183	13,621,027	13,866,205	14,115,797	14,369,881	14,628,539	14,891,853	15,159,906	15,432,785	15,710,575
Secondary electrical energy production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rate	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal energy production	95,309	95,309	95,309	95,309	95,309	95,309	95,309	95,309	95,309	95,309	95,309	95,309	95,309	95,309	95,309	95,309	95,309	95,309	95,309	95,309
Rate $/MMBTU	16	16	17	17	17	17	18	18	18	19	19	19	20	20	21	21	21	22	22	22
Total	1,524,941	1,552,390	1,580,333	1,608,779	1,637,737	1,667,216	1,697,226	1,727,776	1,758,876	1,790,536	1,822,765	1,855,575	1,888,975	1,922,977	1,957,591	1,992,827	2,028,698	2,065,215	2,102,389	2,140,232
Carbon Credits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capacity Payment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total potential revenue	12,718,915	12,947,855	13,180,917	13,418,173	13,659,700	13,905,575	14,155,875	14,410,681	14,670,073	14,934,134	15,202,949	15,476,602	15,755,181	16,038,774	16,327,472	16,621,366	16,920,551	17,225,121	17,535,173	17,850,806
% available	85.0%	84.8%	84.7%	84.5%	84.3%	84.2%	84.0%	83.8%	83.6%	83.5%	83.3%	83.1%	83.0%	82.8%	82.7%	82.5%	82.3%	82.2%	82.0%	81.8%
Gross revenue	10,811,077	10,983,666	11,159,009	11,337,151	11,518,137	11,702,013	11,888,824	12,078,617	12,271,440	12,467,341	12,666,370	12,868,576	13,074,010	13,282,723	13,494,769	13,710,199	13,929,069	14,151,433	14,377,346	14,606,866
Expenses																				
Operating and maintenance	5,555,000	5,666,100	5,779,422	5,895,010	6,012,911	6,133,169	6,255,832	6,380,949	6,508,568	6,638,739	6,771,514	6,906,944	7,045,083	7,185,985	7,329,705	7,476,299	7,625,825	7,778,341	7,933,908	8,092,586
Interest on debt	2,084,916	2,046,270	2,003,819	1,957,190	1,905,971	1,849,709	1,787,910	1,720,027	1,645,462	1,563,557	1,473,589	1,374,765	1,266,213	1,146,975	1,015,999	872,131	714,100	540,513	349,839	140,394
Depreciation and amortization	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268
Amortization capital additions		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total expenses	8,867,184	8,939,638	9,010,509	9,079,468	9,146,149	9,210,146	9,271,010	9,328,244	9,381,298	9,429,564	9,472,371	9,508,977	9,538,564	9,560,227	9,572,972	9,575,697	9,567,193	9,546,122	9,511,015	9,460,249
Net Income before corporate taxes	1,943,894	2,044,028	2,148,500	2,257,683	2,371,988	2,491,867	2,617,814	2,750,373	2,890,142	3,037,778	3,193,999	3,359,599	3,535,446	3,722,496	3,921,797	4,134,502	4,361,876	4,605,310	4,866,332	5,146,617
Corporate taxes	777,558	817,611	859,400	903,073	948,795	996,747	1,047,125	1,100,149	1,156,057	1,215,111	1,277,600	1,343,840	1,414,179	1,488,998	1,568,719	1,653,801	1,744,751	1,842,124	1,946,533	2,058,647
Net income	1,166,336	1,226,417	1,289,100	1,354,610	1,423,193	1,495,120	1,570,688	1,650,224	1,734,085	1,822,667	1,916,400	2,015,759	2,121,268	2,233,498	2,353,078	2,480,701	2,617,126	2,763,186	2,919,799	3,087,970
Retained earnings - beginning		1,166,336	1,226,417	1,289,100	1,354,610	1,423,193	1,495,120	1,570,688	1,650,224	1,734,085	1,822,667	1,916,400	2,015,759	2,121,268	2,233,498	2,353,078	2,480,701	2,617,126	2,763,186	2,919,799
Dividends		1,166,336	1,226,417	1,289,100	1,354,610	1,423,193	1,495,120	1,570,688	1,650,224	1,734,085	1,822,667	1,916,400	2,015,759	2,121,268	2,233,498	2,353,078	2,480,701	2,617,126	2,763,186	2,919,799
Retained earnings - end	1,166,336	1,226,417	1,289,100	1,354,610	1,423,193	1,495,120	1,570,688	1,650,224	1,734,085	1,822,667	1,916,400	2,015,759	2,121,268	2,233,498	2,353,078	2,480,701	2,617,126	2,763,186	2,919,799	3,087,970

Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
ASSETS																				
Cash	2,340,562	3,231,602	4,084,483	4,895,403	5,660,181	6,374,227	7,032,498	7,629,455	8,159,012	8,614,485	8,988,534	9,273,093	9,459,305	9,537,438	9,496,804	9,325,662	9,011,117	8,539,003	7,893,760	7,058,297
Accounts receivable	900,923	915,305	929,917	944,763	959,845	975,168	990,735	1,006,551	1,022,620	1,038,945	1,055,531	1,072,381	1,089,501	1,106,894	1,124,564	1,142,517	1,160,756	1,179,286	1,198,112	1,217,239
	3,241,486	4,146,907	5,014,401	5,840,166	6,620,026	7,349,395	8,023,234	8,636,006	9,181,632	9,653,430	10,044,065	10,345,475	10,548,806	10,644,331	10,621,368	10,468,179	10,171,873	9,718,289	9,091,873	8,275,536
Capital Assets																				
Non depreciable	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciable	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040
	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040	36,818,040
Accumulated depreciation	1,227,268	2,454,536	3,681,804	4,909,072	6,136,340	7,363,608	8,590,876	9,818,144	11,045,412	12,272,680	13,499,948	14,727,216	15,954,484	17,181,752	18,409,020	19,636,288	20,863,556	22,090,824	23,318,092	24,545,360
Net	35,590,772	34,363,504	33,136,236	31,908,968	30,681,700	29,454,432	28,227,164	26,999,896	25,772,628	24,545,360	23,318,092	22,090,824	20,863,556	19,636,288	18,409,020	17,181,752	15,954,484	14,727,216	13,499,948	12,272,680
Total assets	38,832,258	38,510,411	38,150,637	37,749,134	37,301,726	36,803,827	36,250,398	35,635,902	34,954,260	34,198,790	33,362,157	32,436,299	31,412,362	30,280,619	29,030,388	27,649,931	26,126,357	24,445,505	22,591,821	20,548,216
LIABILITIES																				
Accounts payable	462,917	472,175	481,619	491,251	501,076	511,097	521,319	531,746	542,381	553,228	564,293	575,579	587,090	598,832	610,809	623,025	635,485	648,195	661,159	674,382
Corporate taxes	777,558	817,611	859,400	903,073	948,795	996,747	1,047,125	1,100,149	1,156,057	1,215,111	1,277,600	1,343,840	1,414,179	1,488,998	1,568,719	1,653,801	1,744,751	1,842,124	1,946,533	2,058,647
	1,240,474	1,289,786	1,341,018	1,394,324	1,449,871	1,507,844	1,568,445	1,631,895	1,698,438	1,768,339	1,841,893	1,919,418	2,001,269	2,087,830	2,179,528	2,276,826	2,380,236	2,490,319	2,607,692	2,733,029
Long term debt	21,698,231	21,266,992	20,793,303	20,272,984	19,701,446	19,073,647	18,384,049	17,626,567	16,794,520	15,880,569	14,876,649	13,773,905	12,562,609	11,232,075	9,770,566	8,165,188	6,401,779	4,464,784	2,337,114	0
Total liabilities	22,938,705	22,556,778	22,134,321	21,667,308	21,151,317	20,581,491	19,952,493	19,258,462	18,492,958	17,648,908	16,718,541	15,693,323	14,563,878	13,319,906	11,950,093	10,442,014	8,782,015	6,955,103	4,944,806	2,733,029
EQUITY																				
Capital	14,727,216	14,727,216	14,727,216	14,727,216	14,727,216	14,727,216	14,727,216	14,727,216	14,727,216	14,727,216	14,727,216	14,727,216	14,727,216	14,727,216	14,727,216	14,727,216	14,727,216	14,727,216	14,727,216	14,727,216
Retained earnings	1,166,336	1,226,417	1,289,100	1,354,610	1,423,193	1,495,120	1,570,688	1,650,224	1,734,085	1,822,667	1,916,400	2,015,759	2,121,268	2,233,498	2,353,078	2,480,701	2,617,126	2,763,186	2,919,799	3,087,970
Total equity	15,893,552	15,953,633	16,016,316	16,081,826	16,150,409	16,222,336	16,297,904	16,377,440	16,461,301	16,549,883	16,643,616	16,742,975	16,848,484	16,960,714	17,080,294	17,207,917	17,344,342	17,490,402	17,647,015	17,815,186
Total Liabilities and Equity	38,832,258	38,510,411	38,150,637	37,749,134	37,301,726	36,803,827	36,250,398	35,635,902	34,954,260	34,198,790	33,362,157	32,436,299	31,412,362	30,280,619	29,030,388	27,649,931	26,126,357	24,445,505	22,591,821	20,548,216
Return on Investment																				
Earnings before tax	1,943,894	2,044,028	2,148,500	2,257,683	2,371,988	2,491,867	2,617,814	2,750,373	2,890,142	3,037,778	3,193,999	3,359,599	3,535,446	3,722,496	3,921,797	4,134,502	4,361,876	4,605,310	4,866,332	5,146,617
Interest on long term debt	2,084,916	2,046,270	2,003,819	1,957,190	1,905,971	1,849,709	1,787,910	1,720,027	1,645,462	1,563,557	1,473,589	1,374,765	1,266,213	1,146,975	1,015,999	872,131	714,100	540,513	349,839	140,394
Earnings before interest and tax	4,028,809	4,090,298	4,152,319	4,214,873	4,277,959	4,341,576	4,405,724	4,470,400	4,535,604	4,601,334	4,667,588	4,734,364	4,801,659	4,869,471	4,937,796	5,006,633	5,075,976	5,145,824	5,216,170	5,287,012
Investment - Net debt & equity	36,818,040	37,591,783	37,220,625	36,809,618	36,354,810	35,851,855	35,295,983	34,681,953	34,004,007	33,255,822	32,430,451	31,520,264	30,516,881	29,411,093	28,192,789	26,850,860	25,373,105	23,746,121	21,955,186	19,984,129
Return on Investment (ROI) before tax	10.94%	10.88%	11.16%	11.45%	11.77%	12.11%	12.48%	12.89%	13.34%	13.84%	14.39%	15.02%	15.73%	16.56%	17.51%	18.65%	20.01%	21.67%	23.76%	26.46%
Return on Investment (ROI) after tax	6.57%	6.53%	6.69%	6.87%	7.06%	7.27%	7.49%	7.73%	8.00%	8.30%	8.64%	9.01%	9.44%	9.93%	10.51%	11.19%	12.00%	13.00%	14.25%	15.87%
Return on equity (ROE) after tax	7.34%	7.72%	8.08%	8.46%	8.85%	9.26%	9.68%	10.13%	10.59%	11.07%	11.58%	12.11%	12.67%	13.26%	13.87%	14.52%	15.21%	15.93%	16.69%	17.50%

Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Cash From Operations																				
Net Income	1,166,336	1,226,417	1,289,100	1,354,610	1,423,193	1,495,120	1,570,688	1,650,224	1,734,085	1,822,667	1,916,400	2,015,759	2,121,268	2,233,498	2,353,078	2,480,701	2,617,126	2,763,186	2,919,799	3,087,970
Depreciation and amortization	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268	1,227,268
	2,393,604	2,453,685	2,516,368	2,581,878	2,650,461	2,722,388	2,797,956	2,877,492	2,961,353	3,049,935	3,143,668	3,243,027	3,348,536	3,460,766	3,580,346	3,707,969	3,844,394	3,990,454	4,147,067	4,315,238
Cash From Financing																				
Bank loan																				
Accounts payable	462,917	9,258	9,444	9,632	9,825	10,022	10,222	10,426	10,635	10,848	11,065	11,286	11,512	11,742	11,977	12,216	12,460	12,710	12,964	13,223
Corporate taxes payable	777,558	40,054	41,789	43,673	45,722	47,951	50,379	53,024	55,908	59,054	62,489	66,240	70,339	74,820	79,720	85,082	90,950	97,374	104,408	112,114
Debt	22,090,824																			
Capital addition debt		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capital	14,727,216																			
Total cash provided	38,058,514	49,312	51,232	53,306	55,547	57,973	60,601	63,450	66,543	69,902	73,553	77,526	81,850	86,562	91,697	97,298	103,410	110,083	117,372	125,338
Cash Used																				
Accounts receivable	900,923	14,382	14,612	14,845	15,082	15,323	15,568	15,816	16,069	16,325	16,586	16,850	17,119	17,393	17,670	17,953	18,239	18,530	18,826	19,127
Land	0																			
Buildings and equipment	36,818,040	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Debt repayment	392,593	431,239	473,689	520,319	571,538	627,799	689,599	757,481	832,047	913,952	1,003,920	1,102,744	1,211,296	1,330,534	1,461,509	1,605,378	1,763,409	1,936,995	2,127,670	2,337,114
Dividends	0	1,166,336	1,226,417	1,289,100	1,354,610	1,423,193	1,495,120	1,570,688	1,650,224	1,734,085	1,822,667	1,916,400	2,015,759	2,121,268	2,233,498	2,353,078	2,480,701	2,617,126	2,763,186	2,919,799
Total cash used	38,111,556	1,611,958	1,714,718	1,824,264	1,941,230	2,066,315	2,200,286	2,343,986	2,498,339	2,664,362	2,843,172	3,035,994	3,244,175	3,469,194	3,712,677	3,976,409	4,262,349	4,572,652	4,909,682	5,276,040
Net cash provided (used)	2,340,562	891,039	852,882	810,920	764,778	714,046	658,271	596,956	529,557	455,474	374,049	284,559	186,211	78,133	-40,634	-171,141	-314,545	-472,114	-645,243	-835,464
Cash - beginning		2,340,562	3,231,602	4,084,483	4,895,403	5,660,181	6,374,227	7,032,498	7,629,455	8,159,012	8,614,485	8,988,534	9,273,093	9,459,305	9,537,438	9,496,804	9,325,662	9,011,117	8,539,003	7,893,760
Cash - end	2,340,562	3,231,602	4,084,483	4,895,403	5,660,181	6,374,227	7,032,498	7,629,455	8,159,012	8,614,485	8,988,534	9,273,093	9,459,305	9,537,438	9,496,804	9,325,662	9,011,117	8,539,003	7,893,760	7,058,297