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DEVELOPMENT OF A MICRO-TURBINE PLANT TO RUN ON GASIFIER PRODUCER GAS

CONTRACT NUMBER: B/U1/00762/REP

URN NUMBER: 04/1804

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DEVELOPMENT OF A MICRO-TURBINE PLANT TO RUN ON GASIFIER PRODUCER GAS

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Contractor

Biomass Engineering Ltd.

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EXECUTIVE SUMMARY

The objectives of this work programme were to test a Capstone micro gas turbine on producer gas, initially in a test facility using synthetic producer gas and then at the premises of Biomass Engineering Ltd. with the micro gas turbine coupled to an existing 80kWe downdraft gasifier, operating on clean wood and wood wastes.

Biomass Engineering Limited has succeeded in developing a downdraft gasifier capable of producing a clean, very low tar, low particulate gas of consistent calorific value. The company has successfully coupled the unit to two different gas spark ignition engines and has demonstrated the capability to generate consistent, guaranteed levels of heat and power.

The very high gas quality, which is readily suitable for an engine (as evidenced by over 2500 hours on an installation in Northern Ireland and over 2000 hours operation on their test unit at Newton-le-Willows), enables micro-turbines to be considered as a prime mover for power generation. To this end, the project was concerned with the coupling of an existing test gasifier to a Capstone micro-turbine, model 330. Initial testing took place at Advantica's research laboratories in Loughborough. Tests were carried out passing synthetic producer gas over catalyst blocks to check the flammability of the gases proving that the gases could be easily ignited and achieve very low slippage of CH_4 at less than 2.5wt%. Operation of the Capstone micro gas turbine on 100% producer gas was achieved successfully at a net electrical output of 5.5kWe with very low NOx emissions (< 2ppm).

The micro-turbine was then removed and re-commissioned on site at Biomass Engineering Ltd. facilities. 350 hours of operation were achieved using producer gas and over 800 using natural gas. Problems were, however, experienced during start-up, due to limited access to the control software for the turbine and late delivery of the gas compressor for the micro-turbine. Gas emissions and performance of the micro-turbine were found to be satisfactory; however, more long duration testing of the micro-turbine is required to ensure optimal performance. Use of producer gas achieved similar very low emission levels, using a ceramic filtration system to remove particulates and trace tars.

A techno-economic assessment of the complete biomass gasification system from delivered wood chip to electricity and heat output has been completed. The costings were based on in-house data from Biomass Engineering Ltd., actual equipment costs incurred in the project and a standard methodology using cost factors applied to the process. Biomass inputs ranged from 50-250kg/h (prepared material), corresponding to a net electrical output of 21-108 kWe. The net electricity production costs were excessively high, ranging from > 65p/kWh at 11kWe output to 22p/kWh at 108 kWe net output. The micro-turbine and gas compressor typically comprised over 45-59% of the installed costs.

The main conclusions from the work were that 100% producer gas can be used in the un-modified Capstone model C-330 micro gas turbine. Significant deration of the turbine was experienced, with some loss in efficiency, although limited operational hours did not allow an accurate assessment of the degree of loss in efficiency and deration. The producer gas tested over standard monolith catalyst was readily oxidised and low CH_4 slippage was obtained. The quality of the local electricity network was found to have a detrimental effect on the sustained operation of the micro turbine and as a consequence of unplanned shutdowns due to grid faults and an apparent erroneous fuel gas supply fault, the full 1000 hours of operation was not achieved. Emissions from the turbine were well within permitted emission levels. The conclusions from the techno-economic assessment are that although there are no costs savings to be gained using 30kWe gas turbines, economies of scale may be improved with alternative gas turbines.

Micro-turbines of 30kWe do not offer any economy of scale in gasification systems; therefore future work is required on larger turbines such as the Ingersoll-Rand 250kWe with long duration testing to assess technical and economic performance. This would determine the deration effects on micro turbines at full load using producer gas and any loss in efficiency.

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NOMENCLATURE/GLOSSARY

η	gasification efficiency (typically expressed as a %)
CHP	combined heat and power – recovery of heat with the generation of electricity
DPC	direct plant cost – costs related to the specific piece of equipment for its installation [civils, lagging electrical and instrumentation]
EC	Equipment Cost – purchased cost of the hardware for the process
H_G	lower heating value of the producer gas (kJ/Nm^3)
HHV	higher heating value
H_S	lower heating value of the biomass feedstock (kJ/kg)
kg/s	kilograms per second
kJ	kilojoules (1 x 10^3 J)
kJ/kg	kilojoules per kilogram
kJ/Nm^3	kilojoules per normal metre cubed
LHV	Lower Heating Value
m	mass flow of the biomass feedstock (kg/s)
MGT	micro gas turbine
MJ	megajoules (1 x 10^6 J)
Nm^3	normal metre cubed – volume at standard temperature and pressure (293K and 101.325kPa)
ROCs	Renewable Obligation Certificates – an additional price of 3 p/kWh paid to generators of green electricity on top of the base price.
TPC	Total Plant Cost – direct and indirect costs involved in the installation cost of the equipment including all administration and installation costs
V	volume flow of the producer gas (Nm^3/s)

1. INTRODUCTION

Biomass gasification processes generate organic contaminants in the exit gases that are generally referred to as tar. Before use of the gases in a boiler, engine or turbine, particulate matter and the organic tar must be removed, or reduced to a level that is acceptable to end user requirements. The specifications vary from manufacturer to manufacturer and careful matching of the technology and the end user is required. In addition, the actual determination of the level of ''tars'' is still under development (1, 2).

One of the most significant hurdles leading to the development and subsequent scale up of biomass gasification is gas cleaning for particulate and organic contaminant removal prior to use in power generation applications. Many of the emerging technologies in the UK are small-scale and therefore the end user requirements in terms of gas quality will be strict. Typically, the tar levels are significant from small-scale gasifiers, due to poor design, feedstock specification and poor design. Biomass Engineering Ltd. has, however, overcome the apparent ''tar'' problem by careful control of the gasifier reduction zone and smooth continuous gasifier operation resulting in tar levels of 11mg/Nm^3 in the raw gas (measured by CRE). By achieving such low tar levels, the gas conditioning system can be greatly simplified and significant capital cost savings made. To this end, a small back-pulsable ceramic filtration system was planned to remove particulates and trace organics, leaving a tar and particulate free gas.

Biomass Engineering Ltd. has successfully operated a test gasifier at Newton-le-Willows with a ceramic filter system and have achieved > 3000 of hours operation on a Perkins Elmer engine and an Iveco engine, both solely on producer gas.

1.1 Project Plan

The planned programme of work was:

1. Initial testing by Advantica of synthetic producer gas over a catalyst system and in the Capstone C-330 micro gas turbine (MGT)	Section 3
2. Preparation of the gasification system at Biomass Engineering Ltd. and process modifications.	Section 4
3. Installation and testing of the MGT at Biomass Engineering Ltd.	Section 4
4. Techno-economic assessment of the trials at Biomass Engineering Ltd. and cost projections for systems from 50-250kg/h fuel input.	Section 5

The overall timescale for the work was 24 months from February 2002 to the end of January 2004.

1.2 Current and recent projects on biomass gasification systems coupled to gas turbines

A summary of micro-turbine work involving electrical outputs less than 300kWe is given in Table 1. Within the UK, there has been very little experience on gas turbines coupled to biomass gasifiers. The only company with limited involvement was J.E.T. Ltd., who participated in an EU funded project to investigate systems up to 250kWe. The project was terminated early due to time constraints for other partners (3). Project ARBRE at Eggborough is a 5MWe gas turbine, but it only achieved 6 hours operation before the plant was closed down.

Under the current DTI New and Renewable Energy Programme, the University of Ulster, Bowman and Rural Generation Ltd. are working on coupling their Fluidyne gasifier to a Bowman Power Systems micro-turbine. The project has been delayed due to changes in the turbine configuration and the collapse of Bowman Power Systems into administration.

In the USA, FERCO have a 10MWe CFB high temperature gasifier, which produces a medium calorific fuel gas for use in a 15MWe gas turbine. There has been very little achieved to date on operation of the gas turbine. There is little information on how these projects have progressed since their inception in late 2001.

1.3 Gas quality requirements for gas turbines

Unfortunately, there is little long-term experience in the UK or world-wide on the operation of micro-turbines on producer gas. Some indication of the possible levels of contaminants in the final gas prior to the gas turbine use are summarised in Table 2 and Table 3, based upon manufacturers recommended limits, operational experience and theoretical calculations. The tar level should be viewed as being organic vapours present in the gas which are not aerosols and do not condense, or thermally decompose prior to the turbine inlet. The tar level should preferably be as low as possible.

The ceramic filters used in the work have a maximum particle size cut-off of 1μm, therefore only ultra fine particles could possibly bypass the filter. A particle size analysis of the char from the Biomass Eng. Ltd. test gasifier was made of char particles less than 560μm, which showed that less than 2.2% of the particles were in the size range of 1.5-5.8μm, giving a very low potential fraction capable of passing through the filter. As the ceramic filter operates on the basis of the accumulated char particles acting as a depth filter, it was viewed as highly unlikely that any particles would pass through the filter.

1.4 Gasifier Efficiency

Process measurements are made at various points in the system for the determination of temperatures, pressures and flowrates which allow the mass and energy balance for the gasifier to be calculated. Operational data also allows the efficiency of the gasifier to be calculated.

The gasifier operates at a typical efficiency of 80%. The overall efficiency of the gasification process, η, can be defined as the energy content of the producer gas in relation to the energy content of the solid feedstock, as given in equation {1}.

$$\eta = \frac{H_G V}{H_s m} \qquad \{1\}$$

Where:

η	gasification efficiency (typically expressed as a %)
H_G	lower heating value of the producer gas (kJ/Nm^3)
V	volume flow of the producer gas (Nm^3/s)
H_S	lower heating value of the biomass feedstock (kJ/kg)
m	mass flow of the biomass feedstock (kg/s)

The energy content of the by-products, char and tars, must therefore be considered as losses. Efficiency losses in most gasifiers are in the range 2-30%, related to incomplete conversion that leads to the production of char in the ash or liquid condensate by-products, i.e. tars. Additional heat losses from the reactor (4-10%) and the sensible heat of the producer gas (4-10%) lead to overall losses of 10-50%, which corresponds to an overall conversion efficiency of 50-90%. By improving various features of the gasifier, some of these losses can be reduced, i.e. improved insulation, increased tar destruction and lower char production. Removing char from the gasifier will also lead to a reduction of the gasification efficiency, but the char may be used elsewhere in the process. The Biomass Engineering Ltd. gasifier incorporates features which lead to low heat losses (5%), extremely low loss of energy in the very low quantity of tars (<0.01%), and the remaining energy is retained in the char (15%).

1.5 Mass and Energy balance

Based on data obtained from the unit, by measuring the input mass of wood, recording the duration of the run until total consumption of the wood, measurement of the producer gas flow and composition and other basic pressure and temperature measurements, the overall mass and energy balance for the unit have been calculated. Representations for a 100kg/h throughput are given in Table 4 and Figure 2 for the mass and energy balances respectively, and are based on data and measurements from the Biomass Engineering Ltd. gasifiers using a range of wood feedstocks. Each feedstock will give slightly different values and therefore the data presented should not be viewed as absolute for all possible feedstocks. The, ''typical'', mass balance summary used for the purposes of the cost calculations are given in Table 4.

1.6 Biomass Feedstock

The gasifiers of Biomass Engineering Ltd. have processed a range of materials successfully, including spruce, poplar, pine, mahogany (from furniture offcuts), SRC willow and wood wastes (from pallets and sawmill operations including log strippings and fence post pieces) and compressed leather dust from factory operations. For this work, local wood wastes and poplar pieces (from The Poplar Tree Company) were used.

2. EXPERIMENTAL WORK–EQUIPMENT AT BIOMASS ENGINEERING LTD.

2.1 Gasification System

The gasifier installed at Biomass Engineering Ltd.'s premises is a refractory lined downdraft gasifier, originally constructed in 1997/1998. By having a refractory lined unit, the heat loss from the pyrolysis and reduction zones is reduced, improving tar destruction and thereby increasing the gasifier efficiency, typically 75-80% for most wood fuels. The gasifier nominal throughput is 55-60kg/h of prepared wood and power outputs of up to 80kWe on a gas engine have been achieved. The gasifier is a throated downdraft gasifier, which is refractory cast and has tuyeres equidistant above the reduction zone. Biomass is fed in semi-continuously every 1-2 hours using a high speed belt conveyor, allowing regular refilling of the unit without interrupting consistent gas production. Char and ash are removed by riddling below the reduction zone and are removed from the base of the unit at the end of a run, although this will be automated shortly. The gasifier is double skinned to allow the exiting hot gases to preheat the incoming air, thereby improving the thermal efficiency of the gasifier and cooling the exiting gases. The gas production rate is therefore up to ~ 150Nm^3/h on wood.

2.2 Ceramic Filtration Unit

The ceramic filtration test unit can handle up to 50 Nm^3/h of producer gas – the nominal gas flow from the gasifier is ~ 150Nm^3/h using wood. This gas flow from the gasifier is more than sufficient for the operation of the Capstone micro-turbine, therefore the bulk of the gas is passed through the wet scrubbing unit prior to being flared. The ceramic filtration unit is designed to operate with the parameters given in Table 5. Differential pressure measurement is made over the filter elements and the readings are continuously monitored. When the pressure drop reaches a setpoint, three of the filters are backpulsed with clean producer gas, or occasionally, an inert bottled gas. The dislodged char and ash drops down into the collection drum. The 6 filters are capable of handling the increased gas flow for the brief backpulse time. The 3 groups of 3 filters are back-pulsed in sequence, controlled by independent valves. Madison Filters supplied the elements, as recommended by USF Schumacher (now Pall Schumacher).

Limited attempts have been made in the UK to use ceramics at small-scale, the only known example was Power Gasifiers International (4). 1000 hours operational experience were gained. There are no other small-scale activities in biomass gasification below 1MWe using ceramic filtration to remove the particulates and trace tars. The use of ceramic filtration offers the advantages of a continuous process, which is self-cleaning and therefore lowers maintenance costs. The most notable experience of high temperature hot gas filtration has been the 18MW$_{th}$ Varnämo plant in Sweden, for which some operational data is available. In the Varnämo plant, ceramic elements were used for 1200 hours, but due to three filter failures, these have been replaced with sintered metal elements (5).

2.3 Conventional Gas conditioning system

As noted, the remainder of the producer gas is passed through a water scrubber to cool the gas and remove residual particulates after the cyclone. The moist gas is then cooled further to remove condensate, passed through a gas buffer tank prior to flaring.

2.4 Capstone Micro-turbine Model 330

The basic specifications for the MGT are given in Table 6. To operate in CHP mode the Capstone micro turbine requires a gas compressor (£6,000+) and heat exchangers (£11500 minimum + install components) if the system is to be operated in CHP mode. The Ingersoll Rand microturbine include a gas compressor and integral hot water recovery unit built-in to the unit. Further details on the Capstone are given in Appendix A.

Standard costs do not include shipping, installation, or options and basic units are configured as grid-connected. Stand-alone units are also available at an additional cost. Units can be container mounted in many configurations for portable and remote power applications. Standard micro turbines have approx. 50,000 hours and Ingersoll Rand 80,000 hours lifetime. All units have easy serviceable components, and yearly (8,000 hr) maintenance usually requires simple air and gas filter changes. All of these operational and long-term replacement costs are factored into the electricity production costs as discussed later.

There are two possible modes for the delivery of producer gas to a turbine, either blended with air and then compressed as a mixture to the turbine combustor, or separately delivered under pressure to the turbine. The Capstone MGT operates on the latter principal. Recent work on the explosiveness and flammability of biomass-derived producer gas indicates that there is the significant potential for a compressed mixture to be close to its explosion pressure at 8 bar or 100% producer gas and 2.7 bar for the mixture (6). The compressor requirement for the Capstone is 5 bar g. It is believed that the Flex Energy turbine operates on a premix of gases prior to oxidation over a catalyst. The Capstone C-330 therefore required a gas compressor model HV07G, as recommended by Advantica (from CompAir). Details on the gas compressor are given in Appendix A2.

2.5 Layout of filtration unit and Gasification system

The present gasifier is situated outside the works of Biomass Engineering Ltd., and components of the gas conditioning system and the test engines are located inside. The basic flowsheet for the process, which was used in the techno-economic assessment, is shown in Figure 1.

The ceramic filtration unit is located outside with the gasifier, as shown in Photograph 1. This photograph shows the filtration unit before completion of the installation. The location of the MGT is shown in Photograph 2 and the gas compressor in Photograph 3.

3. TEST WORK AT ADVANTICA

The test work carried out by Advantica is detailed in Appendix C in their report. The initial task in the contract was to assess the viability of operation of the microturbine on producer gas and whether indirect or direct firing of the micro-turbine was possible. To this end, the primary tasks of Advantica were:

- trials of synthetic producer gas/air mixtures over a commercial oxidation catalyst,
- test work on micro-turbine operation with synthetic producer gas to a specification provided by Biomass Engineering Ltd.

Based on prior test work, a synthetic gas was ordered, the composition of this gas is provided in Table 7. This composition was in general agreement with gas samples taken from the test gasifier at Biomass Engineering Ltd.

3.1 Catalytic oxidation tests

3.1.1 Catalytic Rig description

A catalytic test rig as shown in Photograph 4 was used to test various air/fuel mixtures over a monolith catalyst to assess the viability of fuel combustion at low temperatures. A schematic of the catalyst bed system is shown in Figure 3.

The synthetic producer gas was fed into a stream of compressed air, approximating an ideal ratio of 9-11:1 (air: producer gas by volume). The ideal ratio was calculated to be the ideal mixture for producer gas of this specification, whilst maintaining the same mass flow rate per kW generated through the micro-turbine when fuelled with natural gas. After mixing, a sample was drawn into an analysis line fed to gas analysers. A flammability sensor was incorporated into the line as part of the rig safety system. The pressures were essentially ambient, with only the excess pressure required to maintain the flow rate through the system to the flue.

This air-producer gas mixture was fed to a top cylindrical section containing an electrical heater, which simulated the effect of a heat recuperation system that would typically be installed within a micro-turbine system.

The pre-heated air-gas mixture then flowed through the lower unheated catalyst modules, within which were located upstream and downstream thermocouples. The emerging combustion products were fed to an exhaust collection system, which also had a gas sampling line connected to another gas species analyser. The catalysis modules were a modified 3-way exhaust catalyst, based on a system previously developed for natural gas vehicle engines.

3.1.2 Results from the catalytic rig

Several trials were carried out at different fuel/air ratios and preheat temperatures ranging from 150-250°C. The temperature rise across the catalyst block was measured continuously in conjunction with the inlet and exit gas compositions. The air producer gas mixtures burned readily over the blocks and a set of experiments to measure the effects of change in temperature (T) in the blocks and preheat temperatures was carried out. Methane proved the most resistant to oxidation, but the CO and H_2 and were completely oxidised.

It was observed that the fraction of unoxidised methane was inversely-correlated with the temperature increase between the upstream and downstream catalyst module thermocouples. Although the average methane level in the combustion outlet of 0.061 vol% was not high in an absolute sense, this measurement indicated that over 28% of the methane input to the catalyst module remained unoxidised.

Hence it was decided to investigate how this fraction varied with pre-heat temperature. After some optimisation, a preheat temperature of 260°C was used and measurements made. The average level of methane in the combustion outlet stream at stable temperature was found to be 0.004% v/v, this being the lowest methane result obtained. The average increase in temperature between the catalyst thermocouples was 219°C. The fraction of unoxidised methane input was reduced to 2.33%.

3.1.3 Conclusions on catalytic rig test work

- The catalyst modules have proven to be highly effective in oxidising the producer gas fuel components within realistic producer gas-air mixtures over a range pre-heat temperatures. The most resistant fraction to oxidation, the methane component, was 90% oxidised at pre-heat temperatures above approximately 200°C. This temperature is easily attainable in microturbine systems via heat exchangers transferring heat from combustion outlet stream to the input air-fuel stream.
- These results provide an additional mechanism to utilise producer gas as a microturbine fuel should the direct fuelling of the microturbine combustion chamber prove untenable.
- The CO oxidation is extremely effective, with combustion outlet CO levels at least as low as those present in ambient air.
- The catalyst module was capable of oxidising the highest flow-rate of producer gas used in the tests (5.25kWe). Further tests would be required to determine an upper limit to this performance.

3.2 Micro-turbine testwork

3.2.1 Micro-turbine selection

Advantica investigated potential microturbine systems for trials with producer gas and synthetic producer gas. A research system was considered, but later discounted due to technical running issues. Two commercial systems were then considered:

- Bowman (model TG50),

- Capstone Microturbine (model 330).

The Capstone was chosen over the Bowman for the ability to control several aspects of the microturbine operation, particularly the ability to enable variable and low-peak electricity generation demand via remote software control. This was important from the standpoint of managing the demand for fuel in a trial system. The Capstone model had the following specifications:

- variable electrical generation capability 5-30kW,
- maximum pressure inlet: 5bar g,
- automated fuel intake valve opening with feedback provided by gas quality, gas pressure, burner and exhaust temperature sensor parameters and power demand.

3.2.2 Capstone MGT operation

The Capstone design incorporated a user-friendly start-up procedure, which was controlled via Windows PC software. This software automated the following stages:

1. checking fuel pressure prior to start,
2. spinning up of the turbine blades using an external power source,
3. initial fuel injection and ignition,
4. increasing to acceptable burner temperature range,
5. acceleration of rotor when acceptable conditions prevail
6. control of system power to match load to fuel delivery.

These control stages were designed and optimised for operation with fuel close to natural gas specifications although there is a wider tolerance on this unit than is found on most natural gas appliances. However, producer gas has a much lower CV than natural gas (5.2MJ/Nm^3 LHV compared to 35.8MJ/Nm^3 LHV).

During stages 4-6, the PC software applies an algorithm to control the degree to which the main gas supply valve opens, with burner temperature and electrical generation sensor outputs being key to the working of the process.

A feature of the microturbine system is the main control valve, which is designed to make the system robust to variations in the pressure of the delivered natural gas. This feature is driven by an algorithm that notes the combustion temperature, as well as the fuel delivery pressure. The algorithm has a built-in “time constant” to prevent the system from over-reacting to short-term pressure fluctuations. This feature enables the system to cope with fluctuations in natural gas supply, but is equally able to react to variations in the calorific value of the fuel.

3.2.3 MGT testing at Advantica

A range of tests was carried out in order to make the micro-turbine suitable for use on LCV gas. The exact test methods are not detailed here, but the findings and their actions are noted below. Nine runs were carried out, the main difficulty being the switchover from natural gas to producer without causing the MGT to report a fault and shutdown. The detailed analysis of each run is provided in the report submitted by Advantica (see Appendix C).

The problem of the main fuel valve control dynamic range (termed valve headroom in the remainder of this report) and it's ability to keep the fuel supply within the required demand range was an issue that had been identified as a threat to the success of the study prior to test commencement, and it had been noted that it was possible to convert the microturbine to low CV operation. This option had been investigated but would have imposed unacceptably long lead times prior to project commencement. Since no flow measurement devices had been incorporated into the simple fuel delivery system, it was not possible to assess the flow rate demand prior to system shut down. The main conclusions from the testwork were:

- the turbine would not start up solely on producer gas and a control regime of switching from 100% NG to 100% PG was required. As a consequence of this ''blending'', mixing of the gases was required, which caused operational problems with the control valving and the micro-turbine control software
- the gas inlet lines had to be increased in diameter to accommodate the increased volume of producer gas required for operation.
- net electrical output was limited to ~5 kWe due to the constraints imposed by the gas discharge rate from the cylinders supplied by Air Products.
- pre-mixing of the natural gas and producer could cause oscillations in the main fuel valve if not properly mixed, leading to premature micro-turbine shutdown.
- the gas turbine could be successfully switched over to 100% producer gas with stable turbine operation, however further work is required to refine the switching operation.
- average turbine deration at 5 kWe output was 52% (LHV basis), fuel LHV 4.4MJkg, giving an estimated electrical efficiency of ~17%.
- the MGT efficiency drops off significantly at low electrical outputs, dropping to 16-18% at less than 8kWe output.
- emissions from the MGT were very acceptable with consistently low levels of NOx, COx and CH_4. Typical values were 2ppm NOx, CO between 50 and 80ppm and CO_2 of 2.32 to 2.42% and CH_4 of 16-25ppm.

The work undertaken by Advantica clearly demonstrated that the Capstone MGT could be operated on producer gas, even without modifications. However, with a deration of 52% and operating a low electrical output, further work would be required to improve the fuel switching systems and obtain a modified low calorific value fuel Capstone MGT, coupled with operation at the turbines full capacity on producer gas.

4. TEST WORK AT BIOMASS ENGINEERING LTD.

4.1 Configuration of gasifier and MGT

The flowsheet for the installed MGT is given in Figure 1 and the equipment codes are in Table 8. The micro-turbine was decommissioned in 2002 and then delivered to Biomass Engineering Ltd. in October 2002. It had been originally intended that Advantica would loan their gas compressor to Biomass Engineering Ltd. for use, however, this turned out not to be possible. Due to the nature of the producer gas several compressor companies would not supply a unit. CompAir agreed to supply a suitable natural gas compressor, designed for such applications. A review of suitable gas compressors has recently been published, revealing that installed compressor costs can vary significantly from £3200-£6000 (7). Unfortunately the delivery of the second gas compressor was significantly delayed, which had an adverse impact on the operation of the MGT as discussed below.

4.2 Gas cleaning and filtration

The back-pulsable filters are designed to be back-pulsed with the working fluid of the system, i.e. the producer gas. This required modification of the pipework configuration to allow a portion of the compressed producer gas to be used to carry out this function.

Due to the original supplier of the ceramic filter system not being able to provide technical assistance and because the elements were not being back-pulsed as specified, changes were made to the unit to improve its operation and ensure a more uniform delivery of producer gas to the filter elements. The old system used bottled nitrogen to back pulse the elements, which was sufficient to push the gases back into the gasifier and extinguish nearly the entire reaction zone. This obviously was an unsatisfactory method of operation as it diluted the producer gas, causing massive fluctuations in its LHV and poor gas flow to the engine/gas compressor. By use of an additional line on the gas compressor discharge some of the producer gas can be recycled back to a small gas buffer tank, the ceramic filters could then be pulsed with clean producer gas and avoid any problems in changing the LHV of the gas and reducing fluctuations in the air and gas flows through the gasifier.

As the product gas from the gasifier was very low in tars, based on visual inspection of the cooled gas, clean gas from the wet scrubbing system was also used. This gas was also found to be satisfactory for operating the gas compressor. Although no specific analysis was carried out on the filtered gas, it was found to burn very cleanly in the flare having no trace of smoke in the gas prior to combustion.

4.3 Operation of the Capstone MGT at Biomass Engineering Ltd.

Due to lengthy delays in obtaining the correct compressor, the planned experimental program of over 1000 hours operation and runs of 24 hours per day could not be achieved. The replacement gas compressor was delivered and installed in late September 2003. Due to other project commitments, which had not

been foreseen at the start of the contract (an order from the British Leather Corporation for a 100kWth leather waste gasifier in June 2003 and other commissioned testwork), operation of the gas compressor and micro-turbine could not start until late October 2003.
For operation of the system, the general tasks required by the personnel were:- wood fuel feed to conveyor system, gasification ignition, manual valve change over, ash residue removal and data monitoring.

The MGT once installed with the gas compressor was re-commissioned on natural gas. This highlighted some of the sensitivities within the MGT control algorithms. If the MGT detects fluctuations in the local electricity grid to which it is supplying electricity, the MGT will regularly ''trip'' and shutdown. It was observed that when running on natural gas, or producer gas, the MGT would shutdown, sometimes after a few minutes operation. It was therefore not possible to leave the MGT unattended during operation on producer gas.

This instability generated further complications on the electrical control detection regime, showing a further fault again shutting down the MGT. The fault being detected was read as a lack of fuel availability, demand, which was the opposite of the actual detection as the MGT programming was technically miss -registering the problem. On assessment of the fault by the turbine control engineer, the programming software could not be amended to suit the new valve parameters. As the MGT powers up, there are several critical measurements it makes on fuel flow, combustor temperature and gas exit temperature. If the measured deviations are too significant, the MGT will close down. This occurred on a regular basis as the manual switchover to producer gas was found to be very difficult and due to the time constraints, no further control equipment could be used to overcome this issue.

The fault registering could be checked via the installed telephone line Modem link and PLC, but the nature of the faults and their regularity meant that the MGT engineer had to visit site to assess and check all the possible factors contributing the fault registering specifically to MGT shutdown. The most common fault being the grid connection failure, which was outside the boundary under our full control. The MGT engineer from Advantica stated that this seemed a common fault in the area, as similar problems were being experienced on other local installations. As noted by Advantica, this is subject to the control parameters within the MGT algorithms and there was little which could be done to change the software settings.

4.4 Analyses

It had also been intended to involve CRE Energy in the testing of the product gases for tars and particulates prior to the ceramic filter and prior to the MGT, but due to re-organisation of CRE, initially as part of EMC Environmental Engineering and then Casella changes in staff and relocation, none of these tests were performed. CRE Energy were originally chosen as they were the UK representatives on the EU funded program on tar protocols for gasification. Therefore, no other analysis company could offer the relevant skills or experience in sampling a biomass gasifier. Gas analyses by gas chromatography (GC) were carried out under subcontract to Aston University, Birmingham, which confirmed the high quality of the gas in terms of a good lower heating value (LHV). The LHV of the product gases typically ranged from 5.0-5.2MJ/Nm^3. A typical gas analysis is given in Table 9.

4.5 Conclusions on operation of the MGT at Biomass Engineering Ltd.

- experimental campaign curtailed due to gas compressor mechanical problems. Late delivery and installation curtailed the experimental programme as the gasifier had been commissioned for operation on other feedstocks for private clients.
- MGT successfully recommissioned on natural gas with 850 hours operation. As noted, there were several occasions when due a local grid problem, the MGT would shutdown and therefore operation was not 24 hours a day, 7 days a week. The problem with the MGT control software detecting fluctuations in the local grid was outside the control of Biomass Engineering Ltd..
- MGT successfully operated on producer from clean wood feedstock, however, only 350 hours intermittent operation was obtained due to a common fault of the grid connection failure. Stabilisation of the gas flows to the MGT proved difficult as some gas was taken for the back-pulsing of the filter elements.
- local grid problems meant that continuous operation was not possible. The control algorithms are very sensitive to fluctuations in the ''quality'' of the electricity network and this would cause synchronisation difficulties, causing the MGT to shutdown.
- gas quality from the gasifier was acceptable to the MGT. Gas samples were taken for analyses and were found to be within a range of 5-5.2MJ/m^3 for the poplar and softwood feedstocks.
- emissions from the MGT were very comparable to that of the work carried out by Advantica. Gas emissions similar to that achieved on the synthetic producer gas were achieved, as tested using online gas analysers wit very low CH_4 slippage and very low NOx emissions, well below emission level requirements.

5. TECHNO-ECONOMICS OF BIOMASS GASIFICATION AND MICROTURBINE SYSTEMS

There has been little work done on the costing of small-scale biomass gasification systems, as most installations are very specific to the local conditions and costs are therefore highly variable. For the purpose of this work, a standard cost estimation approach was used to determine indicative costs of the Biomass Engineering Ltd. dry gas cleaning system, using a back-pulsable filtration system. The advantages of a dry gas conditioning system are:

- avoidance of use of wet scrubbing, which generates a significant quantity of dilute waste requiring treatment at a cost.
- gasifiers, which have very low tar production, are more suited to a dry gas conditioning system, as the main contaminant to be removed is char and ash particles.
- system can be automated for continuous cleaning of the filter elements, reducing labour requirements and solids handling problems.
- system can operate in more extreme climates of low temperatures as no water required in the process.
- catalytic filter elements can be used to remove some trace contaminants (NOx) as required.

5.1 Methodology

Costs associated with the production of electricity produced by biomass gasification comprise an annual cost of capital (assuming all of the capital is loaned), to which are added the annual operating costs of the plant. The operating costs comprise feedstock cost, labour, utilities, maintenance and overheads. The cost of electricity is obtained by summing the production cost elements, and dividing by the total annual production of electricity and also the variant of combined heat and power, taking into account revenues from the sale of heat. Recoverable usable heat was assumed to be double the electrical output, based on process mass and energy balances. The methodology for calculating each of the production cost elements is outlined as follows:

5.2 Capital Cost

Capital cost is calculated as a total plant cost, which includes both direct costs (installed equipment) and indirect costs (engineering, design, supervision, management, commissioning, contractor's fees, interest during construction, contingency). The validity of any model can only be confirmed by comparison with actual cost data for installed plants. Unfortunately, there are few operational small-scale biomass gasifiers in the UK, which are not specifically built for the application and the comparison of costs on a consistent basis is always very difficult. The supplementary information included engineering, design, management and estimate of commissioning costs, with detailed engineering drawings for the entire plant and a basis for the labour costs and man hours involved in the project from conception to completion. The mass balance used as the basis for the cost estimation is given in Table 4 and the energy balance from Figure 2.

5.3 Total Plant Cost

Total plant cost (TPC) is built up in the following manner:

The delivered cost of each process unit shown in Figure 1, referred to as the equipment cost, (EC) is obtained from cost estimation charts for process equipment published by Garrett in 1989 (8) and from Biomass Engineering Ltd's. own cost data for the costs of the installations on site and a detailed internal assessment of plant production costs. The use of published cost estimations from a single source is believed to provide the fairest basis for process cost comparison where other data is not available. Garrett also gives factors for material of construction, which are applied as appropriate. The Capstone turbine costs approximately US$27-35,500, or has been quoted US$600/kWe (9). Values of £19722 for the C-330 MGT and £38116 were used for the C-60 MGT. Other costs for the UK market have been projected at US$900/kWe or US$ 27,000 per unit (10).

The cost estimation charts give equipment cost as a function of either a flow parameter or a dimension parameter, depending on the unit type. Values for flow parameters are obtained directly from the mass balances, scaled appropriately for biomass feed rate. Values for dimension parameters are obtained from the design data for the existing filtration system at Biomass Engineering Ltd.'s site again scaled appropriately for biomass feed rate.

Various items related to installation are then added to the equipment cost EC to give the direct cost for each process unit. This is done using direct cost factors published by the UK Institution of Chemical Engineers (11). The factors take the form given in Equation {2}:

$$F = c(aEC^{b}) \qquad \{2\}$$

where a and b are constants for a given factor, and c is a multiplier to be included if unusual or atypical conditions pertain. Factors are applied for piping, instrumentation, lagging, electrical, civils, structures and buildings. Values for a and b and guidelines for the setting of c are given in Table 12. Actual values used are given in Table 14. The direct cost DC is then given by Equation {3}:

$$DC = EC(1 + \sum F) \qquad \{3\}$$

The direct costs are added to give the direct plant cost (DPC).

Indirect costs are then added to give TPC. This is undertaken using factors published by Bridgwater (12) as presented in Table 13. All costs are brought to a mid-2002 basis using the Chemical Engineering Plant Cost Index as published by Chemical Engineering magazine (11). This allows a consistent approach to be used to derive the relevant cost data for both systems, incorporating in-house and external data as appropriate.

5.4 Operating Cost Calculations

For the operation of the system, it was assumed that 1 operator would be employed to maintain the system during the day and ensure adequate supplies of wood were available after drying and for continuous feeding to the gasifier. The components of the operating cost are: annual cost of capital, labour, utilities (electricity and water), maintenance and overheads.

5.4.1 Capital Amortisation

Capital is amortised using the standard relationship given in Equation {4} below. This is a simplification since the equipment used is likely to have different operational lives and some items may need replacing during the life of the project.

$$\text{Fixed charge, €k/y} = \text{TPC} \times i \times \frac{(1+i)^{l}}{(1+i)^{l}-1} \qquad \{4\}$$

where TPC: Total plant cost, k£
i: annual nominal interest rate, %
l: length of project, years (assumed to be the same as the loan period)

This fixed charge is constant in nominal terms and must therefore be adjusted to real terms for consistency with all other production costs. The cost in real terms of capital amortisation can be calculated for each year of the project by applying Equation {5}. An average of the annual charges is used to give the approximate cost of capital amortisation in real terms.

$$\text{Annual charge, €k/y} = \frac{1}{(1+f)^{n}} \qquad \{5\}$$

where n_x project year
f: annual rate of inflation, %

Other factors assumed in the work are given below in Table 15.

5.4.2 Utilities

Only utility requirements for continuous operation are taken into account; start-up requirements are ignored. The two primary utilities considered are electricity and water and the secondary utility is compressed air. In a complete electricity production plant, the electrical power necessary to operate the plant would be taken

from the gross output from the generator terminals prior to the point of connection to the customer.
The power consumption of fans and pumps is calculated from known flow rates and pressures using in-house data. The power consumption of the conveyors and motors is taken from manufacturers data and scaled appropriately. The difference in gross and net power outputs are given in Figure 8.

Water requirements are for make-up water for the cooling tower. A water price of £0.6/m^3 was taken for replacement of cooling water losses from the cooling tower. For the original system the make-up water for the scrubbing system is also required. The condensate from the process is treated for the purposes of this assessment as effluent and assigned a cost of £0.73/m^3, based on charges from a UK water utility.

5.4.3 Maintenance and overheads

Maintenance and overheads are both included as a fixed percentage of *TPC* per annum. A typical value of 4% was used. Separate consideration was made for the operation of the MGT, as one of the key features was its very low maintenance requirements. Estimated costs for servicing are given in
Table 10. Maintenance contracts are available from Capstone and other vendors. After the one-year warranty period, there may be additional repair costs that the host site may incur.

5.5 Results – Techno-economic assessment

Based on the data given and the methodology presented, the results of the techno-economic assessment are presented in Figure 5, Figure 8 and Figure 9 and Table 8, Table 16 and Table 17. The assessment will discuss the following:

- total plant cost and electrical output (gross and net)
- electricity production cost (wet versus dry, variation with biomass throughput and cost)
- combined heat and power production cost.

5.5.1 Total Plant Cost (TPC) and electrical output

The TPCs for a range of biomass throughputs are given in Table 16 and represented with DPC and EC in Figure 5. The total plant cost is comprised of all the plant components from wood feed to the gasifier to power generation. The cost breakdown for the total system is given in Table 8 for a range of input biomass and electrical outputs (net), showing the very significant contribution made by the gas turbine(s) at all outputs. The TPC range from £386,000 at 21kWe net output to £929,000 at 108 kWe net output.

The electricity production costs are unfeasibly high, due to the substantial turbine deration and very low overall efficiency of only 10.4% - less than a steam cycle at this capacity. This is a very high price for such a system, as each increment of 15 kWe is an additional MGT.

5.5.2 Combined heat and power production costs

The costs for electricity production using a MGT are shown in Figure 8, Figure 9 and Table 17 for a range of biomass feedstock costs. It can be seen that at all capacities, the net electricity production cost is unacceptably high at 58p/kWh for a 21kWe system to 22p/kWh for a 108kWe system in CHP operation and 61p/kWh and 24p/kWh for electricity only at 21kWe and 108kWe net electrical output respectively for a zero cost feedstock. These costs rise significantly with increased feedstock costs as discussed below.
CHP therefore has a very minimal potential to make a significant cost impact for a combined gasification/MGT system and more opportunities for such systems need to be identified. Based on the data presented, the Biomass Engineering Ltd. can be built economically and used in the CHP mode to provide a reliable system for a range of biomass types.

The costing of biomass gasification systems is difficult, as there are usually site-specific costs, which cannot always be allowed for in the determination of generic costs for small scale biomass gasification systems. Although a detailed sensitivity analysis was beyond the scope of this project, the most significant direct factors on the electricity cost are:

- biomass feedstock costs (each £1 increase in feedstock cost is a 1p/kWh increase in net electricity production cost).
- MGT capital cost.
- gas compressor costs.
- low efficiency and substantial deration of the turbine.

Compared with a gas engine system, the net electricity production costs were excessively high, ranging from > 65p/kWh at 21kWe output to 22p/kWh at 108 kWe net output, as the micro-turbine and gas compressor typically comprised over 45-59% of the installed costs. A similar engine system, at 50-250kg/h would have net electricity production costs of 15.5 –7.7p/kWh for a similar engine based system at 50kg/h biomass input, 42kWe net output. All costs assumed wood fuel costs of £25/t, delivered to site. Compared to a biomass gasification + gas engine system, operating at electrical outputs in the top end of the range from 90-110kWe, the MGT system is 3-4 times more expensive.

Although there are no results to date, the use of larger micro-turbines of 250kWe, such as those offered by Ingersoll Rand may be more preferable. Work would be required on assessing the performance of such units and a detailed assessment of their performance made.

A preliminary analysis using the Capstone C-60 (60kWe output on natural gas, cost £38116) showed a cost reduction of 13% at 108kWe net electrical output, due to half the number of turbines being required. Under present circumstances, there is very little prospect for gasifier / MGT systems to be commercially viable using the Capstone C-30 or C-330. To improve the economics substantially, i.e. reduce costs by a factor or 4, turbine deration would need to be zero (not feasible), and preferably larger 250kWe units would be used.

5.6 Techno-economic assessment conclusions

- the installation of a biomass gasification + MGT system in the scale range of 21-108 kWe is financially not feasible, due to the high incremental capital costs for the MGTs and the gas compressors. The MGT and the gas compressors are too expensive for biomass-based systems.
- the MGTs and the gas compressors comprise from 45-59% of the TPC at 21-108kWe net output. This is too high a contribution for two components in the overall cost analysis as there is no economy of scale in installing multiple units, with the high capital costs not being offset with improvements in electrical generation efficiency.
- there is no economy of scale in the use of 30kWe modules and much larger 250kWe units may be more preferable. Further work would be required to ascertain operational experience on such units and a detailed comparison made with standard gas engine systems.
- further work is required to assess the performance of the modified MGT, which may give a better performance and improve the economics.
- significant capital and other allowances would be required to substantially reduce the cost of the systems. In the UK the additional income from ROCs would reduce operational cots by less than 10%.

6. CONCLUSIONS

The overall conclusions from the work are:

- The catalyst modules have proven to be highly effective in oxidising the producer gas fuel components within realistic producer gas-air mixtures over a range pre-heat temperatures. The most resistant fraction to oxidation, the methane component, was 90% oxidised at pre-heat temperatures above approximately 200°C. This temperature is easily attainable in microturbine systems via heat exchangers transferring heat from combustion outlet stream to the input air-fuel stream. The CO oxidation is extremely effective, with combustion outlet CO levels at least as low as those present in ambient air. The catalyst module was capable of oxidising the highest flow-rate of producer gas used in the tests (5.25 kW).
- the gas turbine could be successfully switched over to 100% producer gas with stable turbine operation, however further work is required to refine the switching operation and improve the control algorithms required to do this. Average turbine deration at 5 kWe output was approximately 52% (LHV basis), fuel LHV 4.4MJkg, giving an estimated electrical efficiency of ~17%, although further work at full load is required to improve on this. The emissions from the MGT were very acceptable with consistently low levels of NOx, COx and CH_4. Typical values were 2ppm NOx, CO between 50 and 80 ppm and CO_2 of 2.32 to 2.42 % and CH_4 of 16-25 ppm.

The work at Biomass Engineering Ltd. showed that:

- MGT successfully operated on producer from clean wood feedstock, however, only 350 hours intermittent operation was obtained due to a common fault of the grid connection failure. Stabilisation of the gas flows to the MGT proved difficult as some gas was taken for the back-pulsing of the filter elements.
- local grid problems meant that continuous operation was not possible. The control algorithms are very sensitive to fluctuations in the ''quality'' of the electricity network and this would cause synchronisation difficulties, causing the MGT to shutdown.
- Overall, the MGT could be operated on 100% producer but with extensive deration and a loss in efficiency at the lower power end of the turbine. Higher efficiencies of 24-26% are possible when the turbine is at 100% load, although further work is required to make exact quantification.

In terms of the cost of production of electricity from a gasifier+MGT:

- compared with a gas engine system, the net electricity production costs were excessively high, ranging from > 65p/kWh at 21kWe output to 22p/kWh at 108 kWe net output, as the micro-turbine and gas compressor typically comprised over 45-59% of the installed costs. A similar engine system, at 50-250kg/h would have net electricity production costs of 15.5 –7.7p/kWh for a similar engine based system at 50kg/h biomass input, 42kWe net output.

- Compared to a biomass gasification + gas engine system, operating at electrical outputs in the top end of the range from 90-110kWe, the MGT system is 3-4 times more expensive.

7. ACKNOWLEDGEMENTS

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TABLES

Table 1. Recent and Ongoing biomass gasification + turbine projects

Company& Location	Technology		Feedstocks	Status	Ref.
	Gasifier	Turbine			
UTRC East Hartford, USA	NK	Aero-derivative	Clean wood residues and natural gas	NK	13
Sebesta, Blomberg, Roseville, USA	NK	NK	barley residues and corn stover	NK	13
CSIRO Clayton, Australia	CSIRO Green Gasifier	Capstone 30kWe	Wood waste	Burner testing	14
Flex Energies Inc., Mission Viejo, USA	BG Technologies Gasifier	NK	NK	NK	15

Table 2. Gas Quality Requirements for Gas Turbines (16)

Particulate	30	mg/Nm^3
Particulate size	5	μm
Tar	<50-100	mg/Nm^3
Alkali metals	0.24	mg/Nm^3
Ash (2-20μm: 7.5% and 0-2 μm: 92.5%)	2	ppm
Alkali (Na, K)	0.03	ppm
Calcium	1	ppm
Heavy metals (Pb, V)	0.05	ppm
Sulphur containing compounds	20	ppm
Halogens (HCl, HF)	1	ppm

Table 3. Calculated maximum allowable concentrations in producer gas (17)

Solids (d < 10μm)	5	ppbw
Solids (10μm < d< 13 μm)	30	ppbw
Solids (d > 13 μm)	3	ppbw
Lead	100	ppbw
Alkali metal sulphates	60	ppbw
Calcium	200	ppbw
Vanadium	50	ppbw
Na + K + Li	20	ppbw

Table 4. Mass balance (kg/h) summary based on dry scrubbing system

Description / Component	Wood	Air in	Hot Prods	Hot Gas	Char/ Ash	Condensate	Cold gas	Cooling water
Hydrogen			4.4	4.4			4.4	
Methane			2.1	2.1			2.1	
Water	16.0	2.3	14.9	14.9		14.9	0.0	2551.7
Carbon Monoxide		0.0	49.4	49.4			49.4	
Nitrogen		161.0	151.0	151.0			151.0	
Oxygen		37.8						
Carbon Dioxide		0.9	68.9	68.9			68.9	
C_2+		0.0	<0.01	<0.01			<0.01	
Organics			<0.01					
Wood (d.a.f.)	83.0							
Char			10.0		10.0			
Ash	1.0		1.0		1.0			
Total	100.0	202.0	301.7	290.7	11.0	14.9	275.8	2551.7
Volume, Am^3/h	0.0		676	676			275.8	2.6
Temp In (°C)	25.0	25.0	400.0	400.0	600.0			18.0
Temp Out (°C)	0.0					25.0	25.0	45.0
Pressure kPa Abs	1.0	1.0	1.0	1.0	1.0	1.0	1.0	2.0

Table 5. Operational parameters for the ceramic filters

No. of elements	9
Length	1 m
Diameter	0.15 m
Space velocity	0.02 m/s
Operational temperature	300-700°C
Operational Pressure	Up to 2 bar g

Table 6. Capstone MGT for producer gas. Comparison with other MGTs

Model	Price (UK£, 2004)	Fuel Input (kWth)	Output (kWe)	Efficiency	Notes
Capstone C-30 Capstone C-330	24380	123.1	30	26 ± 2	needs gas compressor and heat recovery
Capstone C-60	38116	255.2	60	28 ±2	needs gas compressor and heat recovery
Ingersoll Rand IR70	61809	266.6	70	27 ±2	all inclusive
Ingersoll Rand IR250	171693	923.0	250	27 ± 2	all inclusive

Table 7. Producer Gas composition and Properties

Gas component	Vol%	Unit
Methane	2.3	%
Carbon Dioxide	14.0	%
Carbon Monoxide	17.5	%
Hydrogen	17.6	%
Nitrogen	48.6	%
Derived Properties	Value	Unit
Calorific Value (Gross†)	5.094	MJ/m^3 at STP
Calorific Value (Net†)	4.676	MJ/Nm^3 at STP
Calorific Value (Gross†)	4.829	MJ/m^3 at NTP
Calorific Value (Net†)	4.433	MJ/Nm^3 at NTP
Average molecular weight	25.745	gm/mol

Notes

† Calculated using Advantica-authored gas properties program, GasVLE Net values are more appropriate, as the gross values assumed combustion product water condensation, which is not achievable in a microturbine system

Table 8. Breakdown of TPC: contribution of plant components to overall cost – variation with plant capacity (net electrical output)

Throughput	kg/h	50	100	125	150	175	200	225	250
Electrical output	kWe	21	43	54	65	75	86	97	108
Code	Description								
C01	Wood Feed Conveyor	7	5	4	4	4	3	3	3
C02	Char/Ash Conveyor	3	2	2	2	2	2	1	1
V01	Gasifier	9	10	11	12	12	11	11	12
V02	Char/Ash Storage Bin	2	1	1	1	1	1	1	1
V03	Demister	1	1	1	0	0	0	0	0
V04	Gas Buffer	3	3	2	3	2	2	2	2
V05	Compressed gas buffer tank	2	2	2	2	1	1	1	1
F01	Air fan	2	2	2	2	2	2	2	2
F02	Gas compressor	13	9	8	8	7	12	11	11
H01	Producer Gas Cooler	3	3	3	3	3	3	3	3
S01	Gas Filter	17	14	13	14	13	11	11	11
S02	Panel filter	1	0	0	0	0	0	0	0
S03	Flare stack	2	2	2	2	2	2	2	2
P01	Cooling tower pump	3	2	2	2	2	2	1	1
F03	Cooling Tower	1	1	1	1	1	1	1	1
T01	Gas turbine	32	42	46	44	47	47	49	48

Table 9. Measured Average Dry Gas analysis from clean softwood (vol%)

Carbon Monoxide (CO)	19.18
Carbon Dioxide (CO_2)	13.34
Hydrogen (H_2)	17.42
Methane (CH_4)	1.80
Ethylene (C_2H_4)	0.34
Ethane (C_2H_6)	0.06
Propylene (C_3H_6)	0.03
Propane (C_3H_8)	0.00
n-Butane (C_4H_{10})	0.00
Nitrogen + Argon (by difference)	47.83
Higher Heating Value (MJ/Nm^3 dry gas)*	5.6
Lower Heating Value (MJ/Nm^3 dry gas)*	5.1
Density (kg/m^3)	1.06

* Normal conditions taken as 20°C, 101325 Pa

Table 10. Standard Service Events for a Capstone MGT

	Service Interval (hours)	Est. Total Service Cost, UK£ (mid 2002)
Thermocouple Replacement	8,000	68
Air Filter	8,000	103
Fuel Filter	8,000	50
Ignitor or Spark Plugs	16,000	253
Fuel Injectors	16,000	472
Engine Overhaul	20,000	3077

Table 11. Gas quality issues (18)

Minimum heating value	5-6	MJ/Nm^3
Minimum gas hydrogen content	10-20	vol%
Maximum alkali concentration	20	ppbw
Maximum delivery temperature	450	°C
Tars, at delivery temperature	all in vapour form, no tar	

Table 12. Direct cost factors

Factor, *f*	*a*	*b*	*c*	
Erection	1.924	-0.261	0.56	low, e.g. erection included
			1.32	high, e.g. some site fabrication
			4.26	very high, e.g. much site fabrication
Piping, ducting	31.953	-0.358	0.3	very low, e.g. ducting only
			0.71	low, e.g. small diameter piping
			1.42	high, e.g. large diameter piping, complex
Instrumentation	13.942	-0.33	0.46	very low, e.g. locate only
			0.8	low
			1.28	high
Electrical	4.2112	-0.231	0.23	very low, e.g. lighting only
			0.83	low, e.g. for ancillary drives only
			1.46	high, e.g. transformers and switchgear
Civil	1.997	-0.231	2.25	high
			2.9	very high
Structures, buildings	4.99	-0.244	0.35	very low, e.g. negligible
			0.83	low, e.g. open air or ground level
			1.18	high, e.g. covered building
			1.89	very high, e.g. elaborate under cover
Lagging	10.338	-0.419	0.61	low, e.g. service only
			1.16	high
			1.84	very high, e.g. cold lagging

Table 13. Indirect cost factors

Item	Range	Factor Used
Direct plant cost (*DPC*)		1.0
Engineering, design and supervision	0.10-0.20	0.15 *DPC*
Management overheads	0.05-0.20	0.10 *DPC*
Installed plant cost (*IPC*)		1.25 *DPC*
Commissioning	0.01-0.10	0.05 *IPC*
Contingency	0.00-0.50	0.10 *IPC*
Contractor's fee	0.05-0.15	0.10 *IPC*
Interest during construction	0.07-0.15	0.08 *IPC*
Total plant cost (*TPC*)		= 1.33 *IPC*
		or = 1.66 *DPC*

Table 14. Nomenclature and Direct Cost factors

			DIRECT COST FACTOR , F							
Eqpt. No.	Equipment	Equipment Type	Erection	Piping (gas)	Piping (liquid)	Instrumentation	Electrical	Civils	Structures	Lagging
C01	Wood Feed Conveyor	Belt conveyor	0.10			0.42	0.47	0.25	0.47	0.00
C02	Char/Ash Conveyor	Conveyor, Screw	0.13			0.54	0.57	0.30	0.57	0.00
V01	Gasifier	Refractory lined, furnace	0.24	0.58		0.29	0.34	0.19	0.34	0.14
V02	Char/Ash Storage Bin	Small Tank, Flat Top and Bottom	0.17	2.47		0.00	0.00	0.38	0.30	0.00
V03	Demister	Small Tank, Flat Top and Bottom	0.30			0.00	0.00	0.38	0.30	0.00
V04	Gas Buffer	Small Tank, Flanged & Dished Heads	0.13	1.53		0.53	0.13	0.30	0.56	0.21
V05	Compressed gas buffer	Small Tank, Flanged & Dished Heads	0.15	1.96		0.64	0.15	0.35	0.66	0.27
F01	Air fan	Axial Small, 1 atm, 0.5 atm vac	0.14	1.41		1.04	0.63	0.33	0.26	0.24
F02	Gas compressor	Natural gas 66 psi discharge	0.09	0.78		0.64	0.42	0.23	0.18	0.00
H01	Producer Gas Cooler	Heat Exchanger, Shell and Tube	0.21	1.59		0.50	0.45	0.29	0.53	0.36
S01	Gas Filter	Baghouse	0.14	0.86		0.20	0.36	0.19	0.35	0.28
S02	Panel filter	Filter	0.32			0.00	0.00	0.41	0.33	0.00
S03	Flare stack	Flare, elevated 40 ft, 5m tall	0.23	1.24		0.35	0.00	0.31	0.57	0.00
P01	Cooling tower pump	Centrifugal Pump, Conventional	0.16		1.49	2.15	0.69	0.36	0.69	0.29
F03	Cooling Tower	Cooling Tower	0.36		1.40	0.00	0.55	0.35	0.00	0.51
T01	Gas turbine	Capstone micro-turbine	0.00	0.10	0.00	0.16	0.19	0.14	0.00	0.00

Table 15. Calculation factors used in the techno-economic assessment

No of plant replications	none
Life of project (years)	20
Interest rate (%)	8%
Inflation rate (%)	2.5%
Labour rate (£/y)	25000 per person
No. of shifts	1
Overheads (%CC/y)	4%
Maintenance (%CC/y)	4%
Availability	90%

Table 16. Total Plant Cost for the MGT systems- variations with biomass throughput and net electrical output

Biomass throughput (kg/h)	50	100	125	150	175	200	225	250
Electrical output (kWe)	21	43	54	65	75	86	97	108
MGT system (£ x 1000) #	386	497	574	649	772	790	860	929

Note: does include MGT cost

Table 17. Net electricity production cost v's electrical output and CHP option. Income 1 p/kWh for CHP option. Variation with feedstock cost

Electrical output (MWh/y)	144	292	366	439	513	586	660	733
	368	736	920	1103	1287	1471	1655	1839
Power only(£0/t)	61	36	33	30	30	26	25	24
Power only(£25/t)	68	43	39	37	36	33	32	31
Power only (£50/t)	74	50	46	43	43	40	39	38
CHP (£0/t)	58	34	30	27	27	24	23	22
CHP (£25/t)	65	41	37	34	34	31	29	28
CHP (£50/t)	72	47	44	41	40	37	36	35

FIGURES

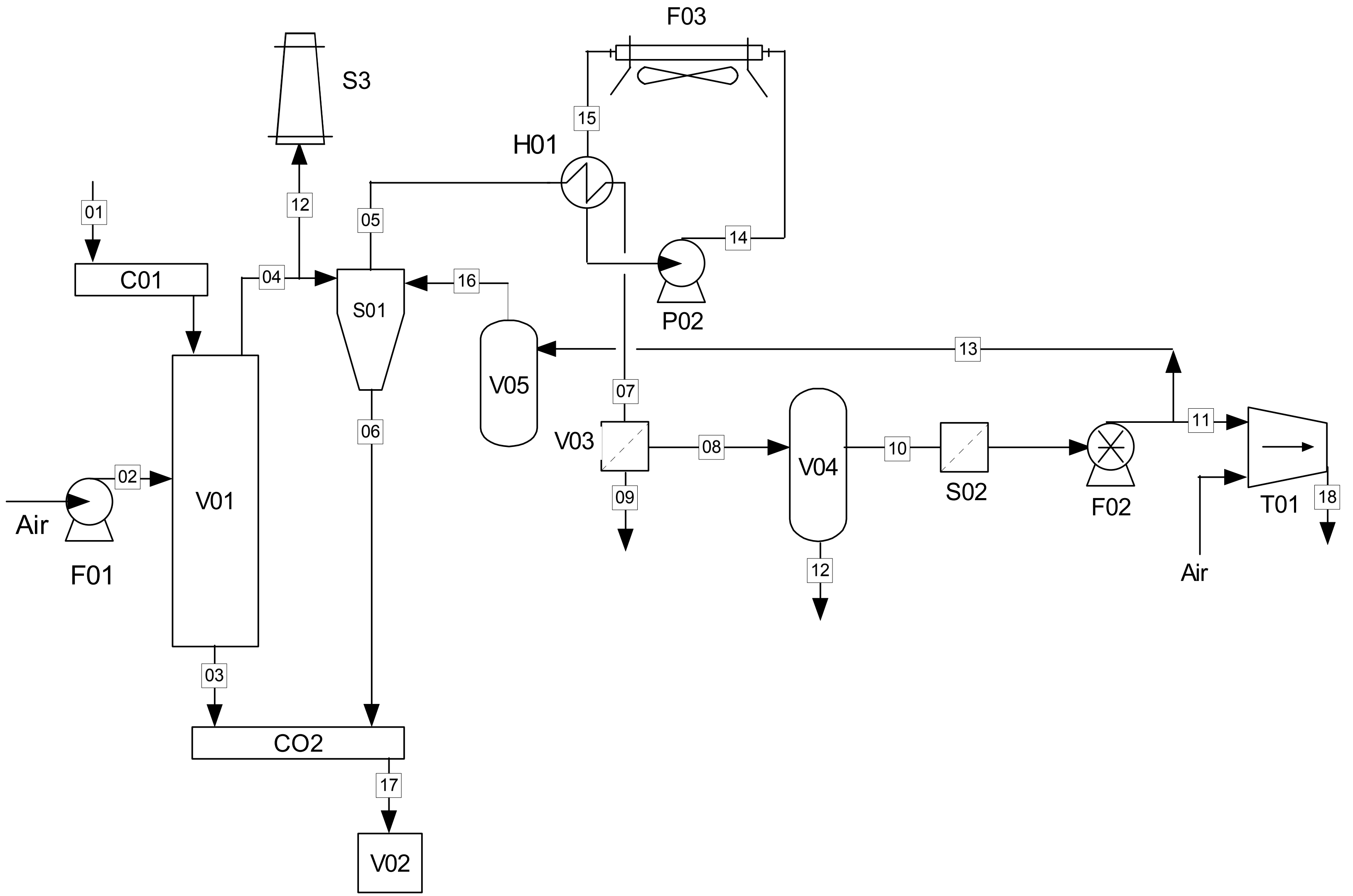


Figure 1. Flowsheet for techno-economic assessment –MGT installation (see Table 14 for equipment codes)

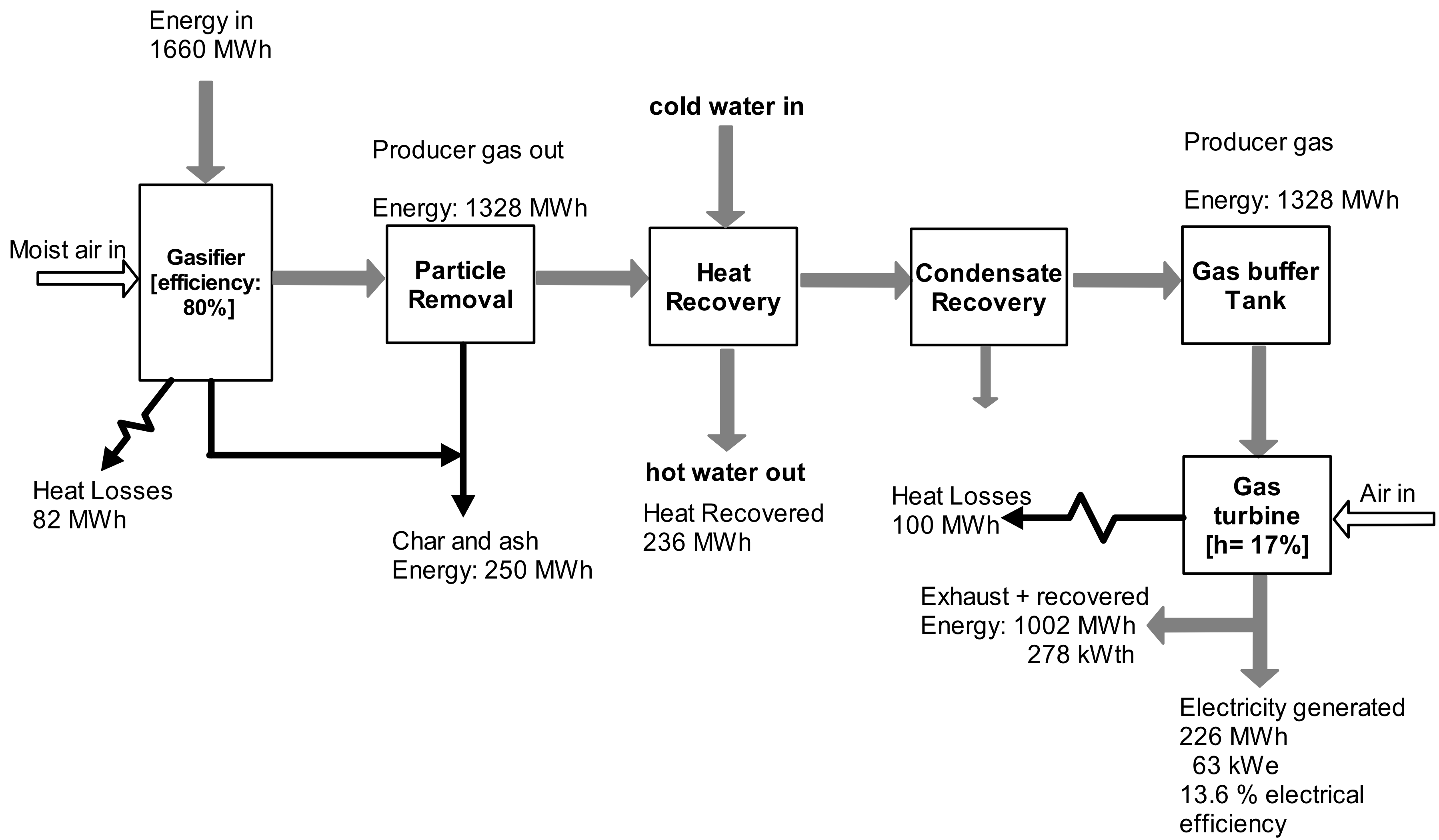


Figure 2. Gasification system Energy Balance

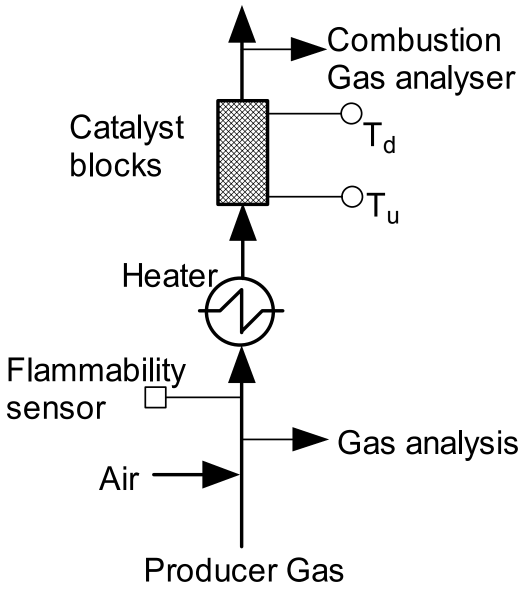


Figure 3. Schematic of catalytic combustor test rig at Advantica

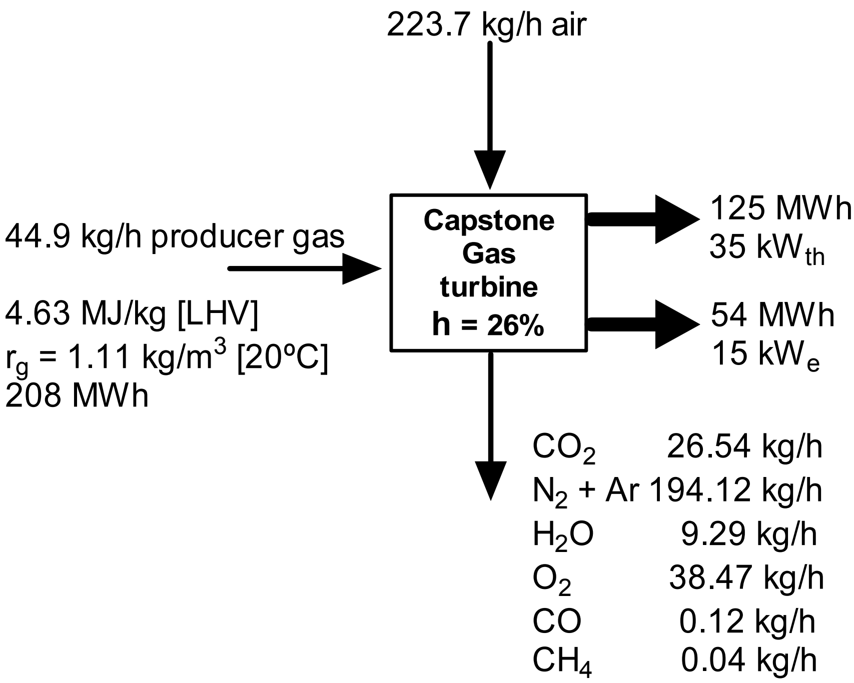


Figure 4. Capstone Gas Turbine Mass Balance

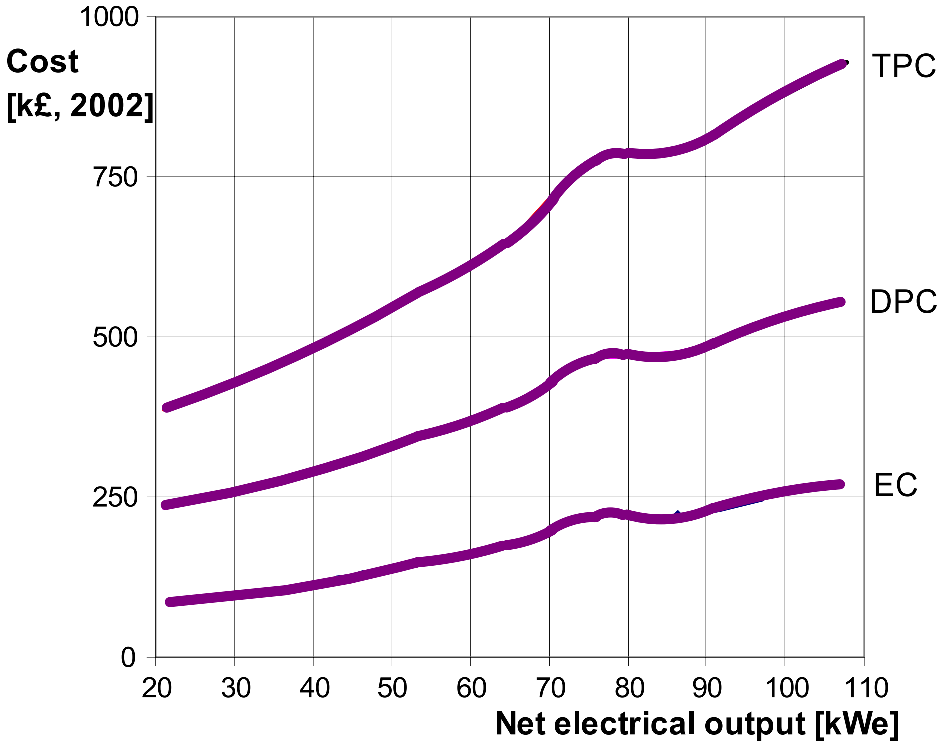


Figure 5. Plant costs: Equipment Cost (EC), Direct Plant cost (DPC) and Total Plant Cost (TPC) v's net electrical output (Model C330 MGT)

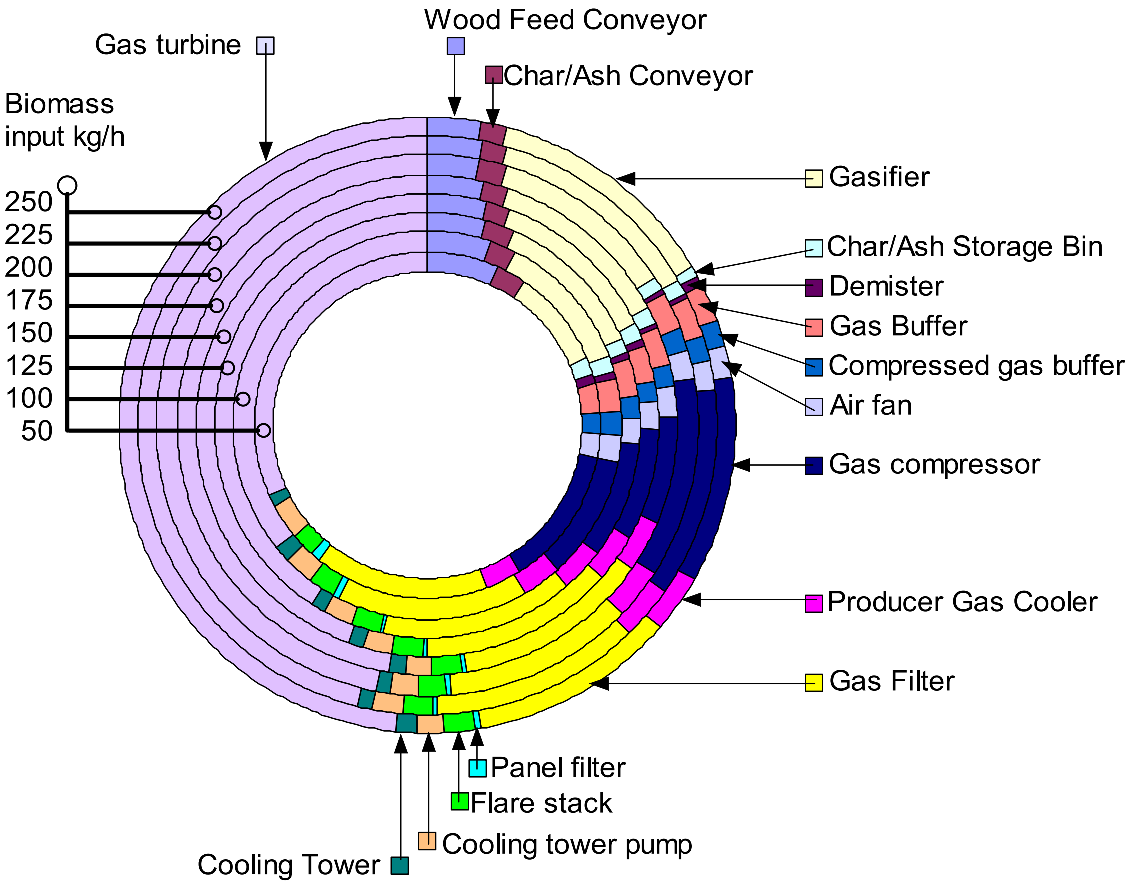


Figure 6. % Contribution of principal plant items to the Direct Plant Cost

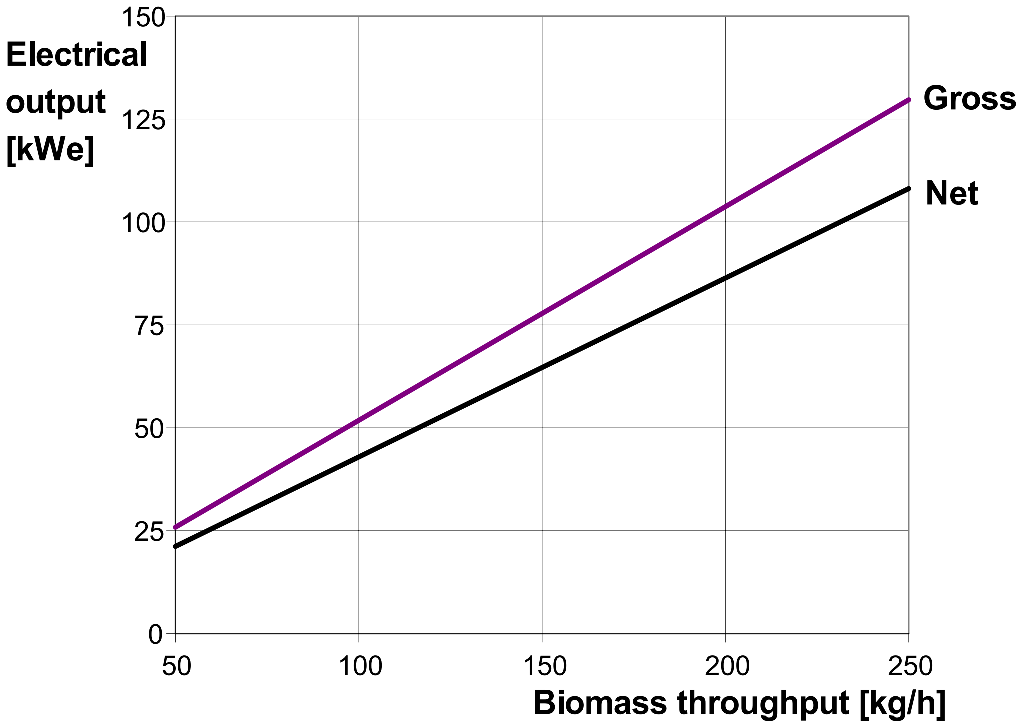


Figure 7. Gross and Net electrical output v's biomass throughput (gasifier efficiency 80%, turbine efficiency 26%, 50% turbine deration)

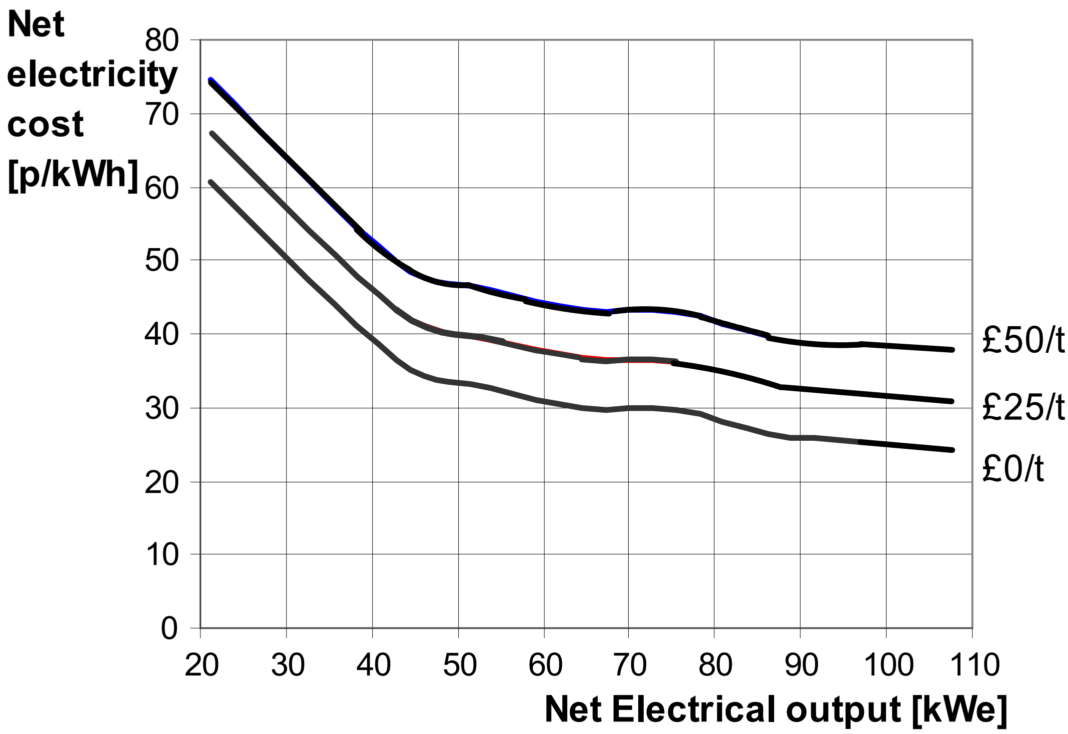


Figure 8. Net Electricity Production cost v's electrical output: variation with prepared feedstock cost

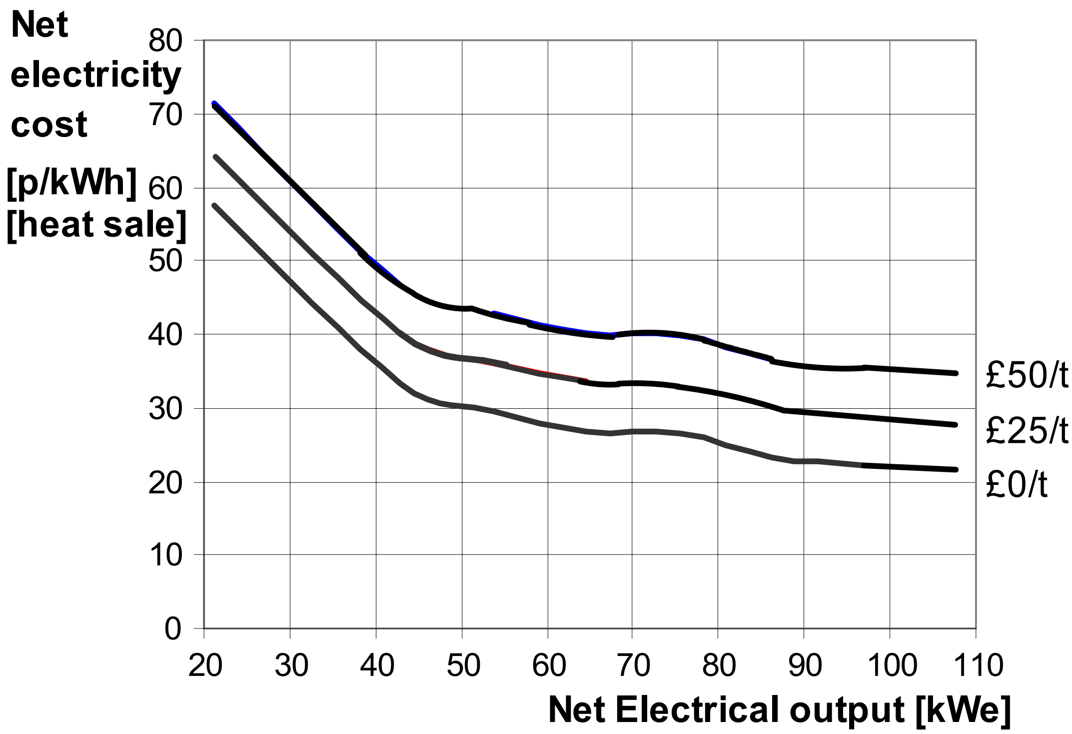
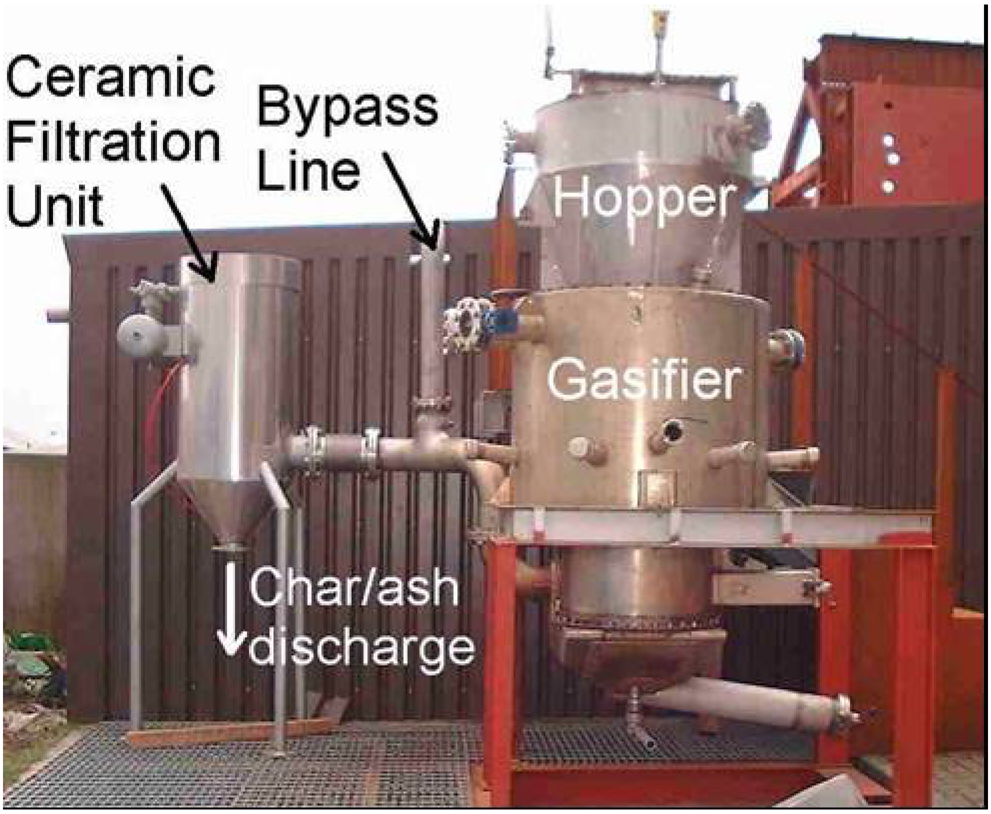


Figure 9. Comparison of net electricity production cost with CHP option – income from heat (1 p/kWh). Variation with feedstock cost

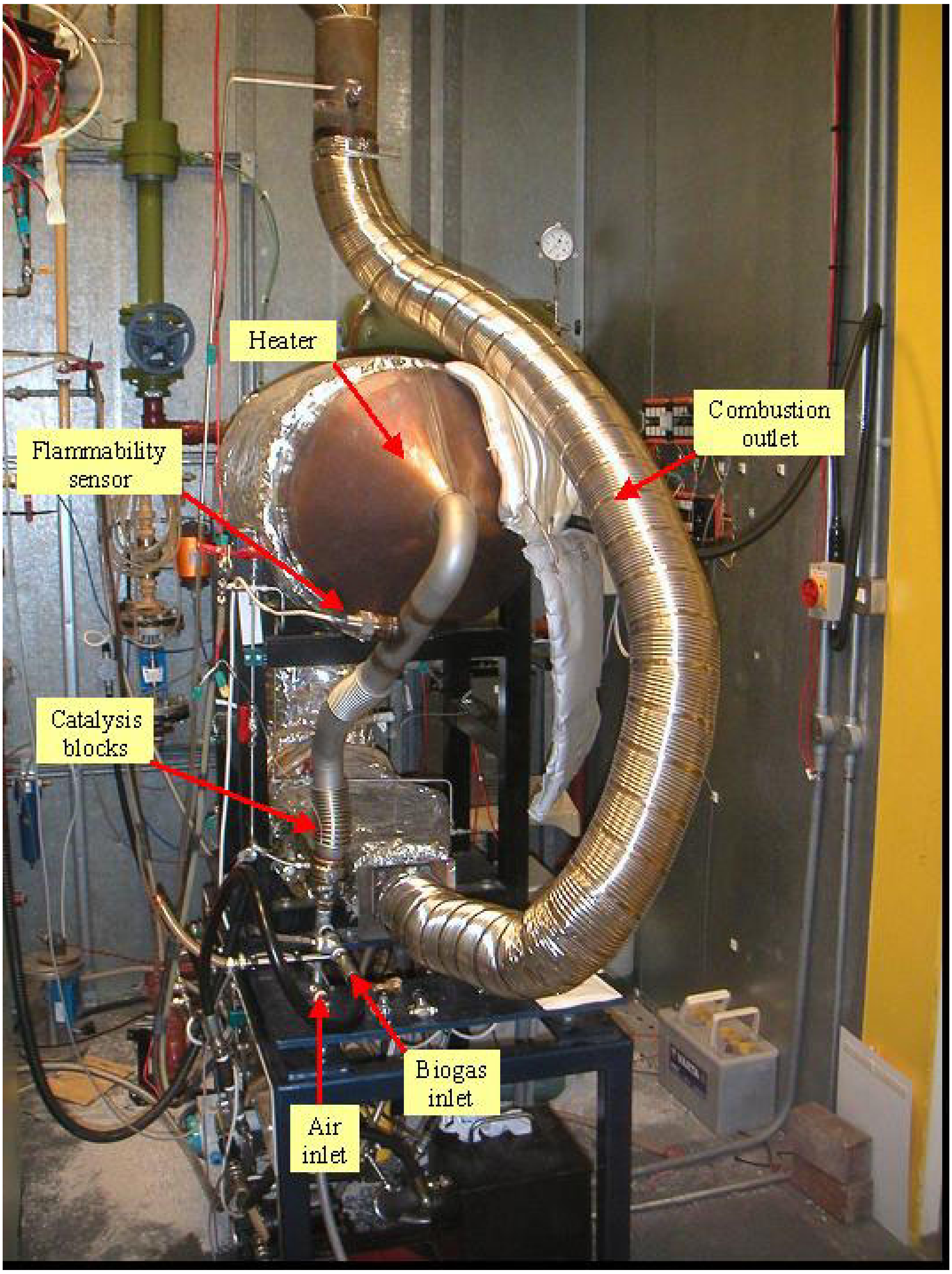
PHOTOGRAPHS



Photograph 1. Gasifier and Test filtration unit without feed conveyor (prior to addition of char/ash bin)

Photograph 2. Capstone micro-turbine in the engine house

Photograph 3. Gas compressor model HV07



Photograph 4. Advantica Catalytic test rig

APPENDIX A

DETAILS ON THE CAPSTONE MICRO-TURBINE MODELS C-330 AND C-30

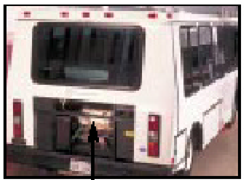
Capstone MicroTurbine™

MODEL 330
HEV MicroTurbine
Multi Fuels

The Product

Features
- 30 kW net (ISO conditions)
- 250V-700V DC
- Patented air bearings
- Digital power controller
- Air cooled
- Fuel flexible, freeze-tolerant
- Permanent flash memory with full operating history.

Benefits
- Near-zero emissions performance
- No fluid lubricants or coolants needed, ever
- Compact size & weight
- Reliable operation
- Fast in-field serviceability
- Minimal maintenance
- Full diagnostic capability
- Suited for a wide range of transport applications



CARB-certified up to 70% lower emissions than EPA 2004 Truck & Bus Regulations ...available today!

HEV EMISSION CYCLE TESTING			
Emissions	**CNG***	**Propane***	**Diesel****
NO_X g/bhp-h	0.26	0.53	0.75
HC g/bhp-h	0.42	0.42	0.30
CO g/bhp-h	0.41	0.18	0.40
PM g/bhp-h	0.004	0.004	.01

* Emissions are actual results per CARB certification. Manufacturer emissions warranty limits are slightly higher
**CARB certification pending Q2 of 2001 - internal test results only

Performance Specifications Under ISO Conditions (15° C / 59° F @ sea level)

MicroTurbine Performance	Fuel Type Natural Gas (55 psig)	Propane (55 psig)	Diesel (5 psig)
Overhaul Life	20,000 hrs	20,000 hrs	20,000 hrs
Full-Load Power	30 kW net (+/- 1 kW)	30 kW net (+/- 1 kW)	29 kW net (+/- 1 kW)
Peak Efficiency (LHV)	27% (+/- 2%)	27% (+/- 2%)	26% (+/- 2%)
Fuel Flow*	18.7 lb/hr / 8.5 kg/hr	19.0 lb/hr / 8.6 kg/hr	21.9 lb/hr / 10.0 kg/hr
Fuel Flow, Equivalent	N/A	4.5 gal/hr / 17.2 l/hr	2.9 gal/hr / 11.0 l/hr
Exhaust Gas Temperature	261°C / 500°F	261°C / 500°F	261°C / 500°F
Output Voltage	250V - 700V DC	250V - 700V DC	250V - 700V DC

*Rated at LHV: 20,167 Btu/lbm (Natural gas); 19,916 Btu/lbm (Propane); 18,250 Btu/lbm (Diesel).

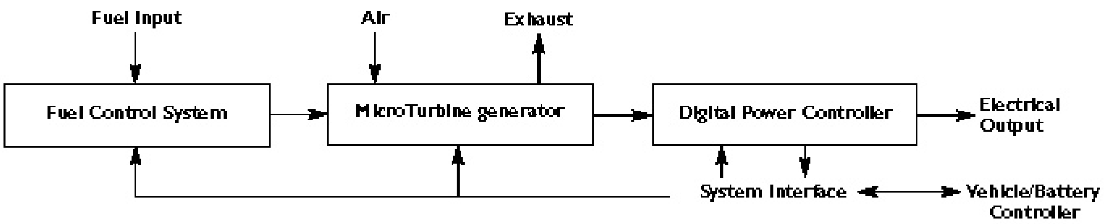
Engine Assembly
Dimensions
L: 836mm / 32.9"
W: 572mm / 22.5"
H: 729mm / 28.7"
Weight
102 kg / 225 lb

Digital Power Controller
Dimensions
L: 825mm / 32.50"
W: 311mm / 12.25"
H: 464mm / 18.25"
Weight
68.5 kg / 151 lb

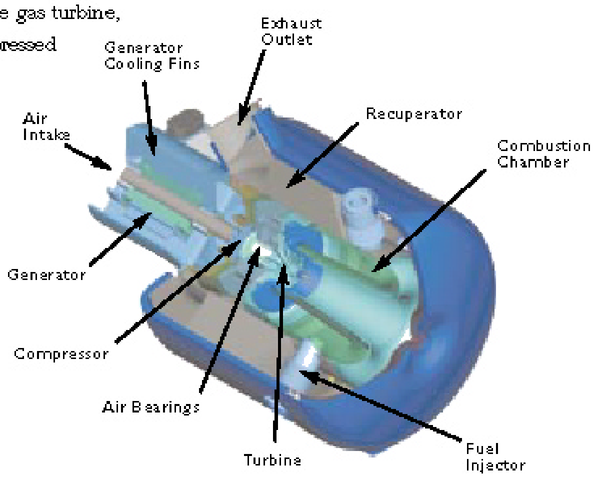
All specifications rated at full-load power.
Note: The manufacturer reserves the right to change or modify without notice, the design or equipment specifications without incurring any obligation either with respect to equipment previously sold or in the process of construction.

CAPSTONE TURBINE CORPORATION
www.microturbine.com

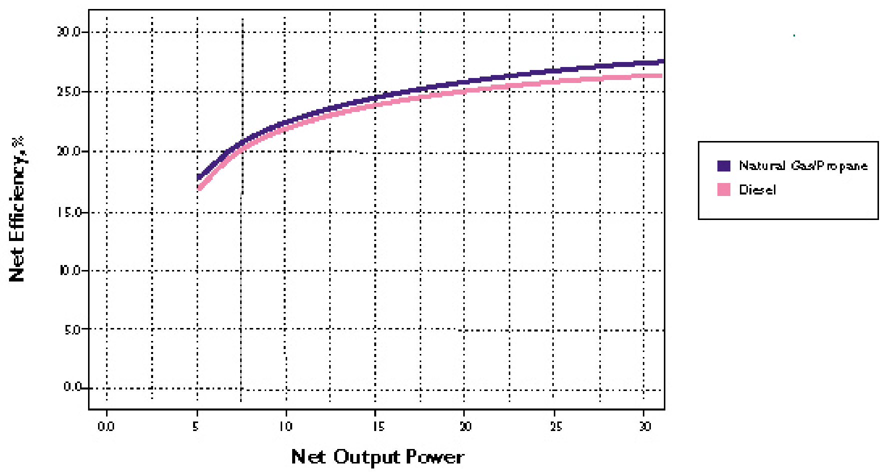
Capstone MicroTurbine™ System



The Capstone MicroTurbine™ system includes a compressor, recuperator, combustor, turbine and permanent magnet generator. The rotating components are mounted on a single shaft supported by air bearings that rotate at up to 96,000 RPM. The generator is cooled by the air flow into the gas turbine, thus eliminating the need for liquid cooling. The air is compressed and injected into the recuperator where its temperature is elevated by the exhaust gases expelled from the turbine. This process increases the system efficiency. The heated compressed air is mixed with fuel and burned in the combustion chamber. The combusted hot gases expand through the turbine, providing the rotational power. Patented techniques in the combustion process result in an extremely low emission exhaust stream. The output of the generator is variable voltage, variable frequency AC power. Power electronics convert this to programmable DC power for HEV applications.



Part Load Efficiency at ISO Conditions



CAPSTONE TURBINE CORPORATION
21211 Nordhoff Street • Chatsworth, CA 91311 • Phone: 818-734-5300 • Fax: 818-734-5320
www.microturbine.com

Capstone

Capstone MicroTurbine™

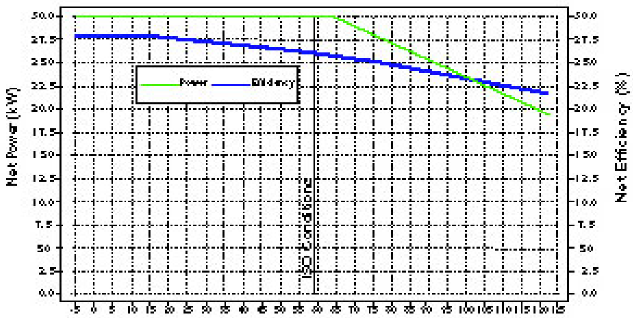
CAPSTONE C30 Biogas

The Product

Features
- Load-following 15-30 kW
- Fuel input as low as 350 Btu/scf
- 360-528 VAC, 50/60 Hz
  3-phase, 3- or 4-wire wye
  46ARMS/phase max continuous
- Maintenance-free air bearings
- No liquid lubricants
- No liquid coolants
- Sour gas tolerant (up to 70,000 ppm)
- Digital power controller
- Built-in display and user interface
- Built-in protective relays
- Built-in MultiPacking of 2-20-units
  (unlimited via grid connect)

Benefits
- Renewable energy from waste
- Greenhouse gas reduction
- Ultra-low emissions
- Minimal maintenance
- Direct2Grid™ interconnection
- No fluid storage, changes, disposal
- Uncontaminated exhaust heat for CHP
- Phase-to-phase balance (0-100%) on stand-alone units
- Small footprint
- Vibration-free, quiet operation
- Easy indoor/outdoor/rooftop siting
- Zero hardware arraying (up to 600 kW)
- Optional remote monitoring

C30 HP Net Power and Efficiency at Ambient Temperature, Sea Level



Compliances
IEEE 519
CEC Rule 21
NYPSC DG
EPA Exempt
CA AQMD Exempt
WY DEQ Exempt
NEMA 3R / IP 14
Others*

CE

Other packaging options also available.

Full Load Specifications @ ISO Conditions (15°C / 59°F @ sea level)

Performance	Power	Efficiency (LHV)	Heat Rate (LHV)
Landfill or digester gas	30 kW net (+0/-1) 38.2 kVA max @ 480 VAC	26% (± 2)	13,800 kJ (13,100 Btu) / kWh

Emissions:

NO_x	<9 ppmV @ 15% O_2 (<0.49 lb/MWh)

Intake/Exhaust

Fuel flow (methane-HHV)	457,000 kJ/hr (433,000 Btu/hr)
Exhaust gas temperature	275°C (530°F)
Mass flow	0.31 kg/s (0.68 lb/s)
Total exhaust energy	327,000 kJ/hr (310,000 Btu/hr)

Pressure Requirements

Btu/scf (HHV)	psig
>1000	55
>600	65
>350	75

Dimensions
H: 1900mm (74.8")
W: 714mm (28.1")
D: 1344mm (52.9")

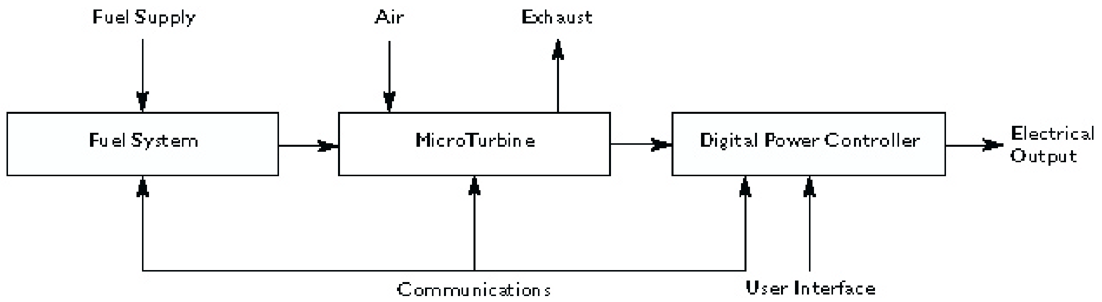
Weight
478 kg (1052 lb)

Sound
65dBA @ 10 m (33 ft)
CE Lwa 98 compliant

* See www.microturbine.com/compliance for detail
Fuel heat content: 12.8 to 42.1 MJ/m³ (350 to 1130 Btu/scf) HHV methane.
The manufacturer reserves the right to change or modify, without notice, the design or equipment specifications without incurring any obligation either with respect to equipment previously sold or in the process of construction. The manufacturer does not warranty the data on this document. Warranted specifications are documented separately.

CAPSTONE TURBINE CORPORATION
www.microturbine.com

Capstone C30 MicroTurbine System

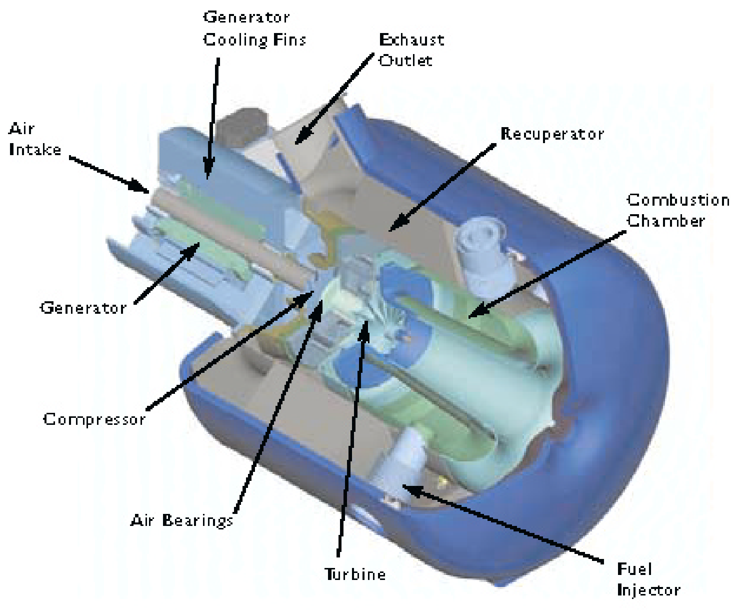


The Capstone C30 MicroTurbine system is a compact, ultra-low-emission generator providing up to 30 kW of power and 85 kW of heat for combined heat and power applications. Solid-state patented power electronics permit 0-30 kW load following, safe zero-hardware Direct2Grid™ interconnection, advanced communications and 2-to-20-unit stand-alone MultiPacking with no external hardware except computer cables. Automatic grid/stand-alone switching, 100-unit PowerServer™ networking, remote monitoring/dispatch and other functionalities are available Capstone options.

The system incorporates a compressor, recuperator, combustor, turbine and permanent magnet generator. The rotating components are mounted on a single shaft, supported by air bearings, that spins at up to 96,000 rpm. This is the only moving part of the microturbine. The generator is cooled by inlet air flow. The system uses no oil, no lubricants, no coolants and has no pumps, gearbox or other mechanical subsystems. The system achieves ultra-low NO_x performance with no post-combustion catalysts or other exhaust cleanup devices. System output is variable frequency (50/60 Hz) 3-phase AC power.

A natural gas fueled 60-kW model and other 30-kW models are also available.

The Capstone C30 MicroTurbine Generator



CAPSTONE TURBINE CORPORATION
REGISTERED TO ISO 9001
FILE NUMBER A9549

CAPSTONE TURBINE CORPORATION
21211 Nordhoff Street, Chatsworth, CA 91311 Phone: 818-734-5300 Fax: 818-734-5320
www.microturbine.com

APPENDIX B

DETAILS ON THE GAS COMPRESSOR

Technical Information

Model	Performance F.A.D l/s (cfm)			Motor Power	Oil Capacity	Noise Levels	Air Outlet	Dimensions			Weight
	7 bar	8 bar	10 bar	kW (hp)	Litres	dBA (open/end)	RP (open/end)	Length (open/end)	Width (open/end)	Height (open/end)	kg (open/end)
HV01	-	-	1.96 (4.2)	1.1 (1.5)	1	62	3/8	700 *1153	270 *300	470 *681	35 *72
HV02	-	-	3.7 (7.9)	2.2 (3.0)							35 *83
HV04	11 (24)	-	9 (20)	4 (5.5)	3	66	3/4	680	470	1050	152
HV05	15 (32)	-	12 (25)	5.5 (7.5)							
HV07	21 (44)	-	17 (35)	7.5 (10)		67					156
HV07RS	0 - 20 (0-42)										160
HV11	-	29.0 (61.4)	24.5 (51.9)	11 (15)	5.7	76/72	3/4	1578/1648	610	976	291/341
HV15	-	38.0 (80.5)	33.3 (70.6)	15 (20)		78/74		1627/1648			324/374
HV15RS	0-39 (0-83)								620		339/389
HV18	-	49.0 (103.8)	42.3 (89.7)	18 (25)	13.6	76/72	1	1772/1778	610	1087	428/480
HV22	-	60.0 (127.1)	52.0 (110.2)	22 (30)		78/74					
HV22RS	0-56 (0-119)								620		443/495
HV30	-	78 (165)	72 (152)	30 (40)		80/73	1¼	2010/1800	867/725	920/1225	510/675
HV37	-	94 (199)	87 (185)	37 (50)	14.5	84/72	1½	2114/1800	910/900	1058/1415	560/780
HV37RS	0-95 (0-200)					84		2108	965	940	771
HV45	-	114 (242)	100 (210)	45 (60)	24	84/73		2141/1800	910/900	1058/1415	620/914
HV55	158 (335)	-	-	55 (75)	42	71	2	2330	955	1600	1450
HV75	211 (447)	-	-	75 (100)		73					

Hydrovane HV02RM
(Receiver Mounted)

Hydrovane HV07

Hydrovane HV11
(Enclosed Option)

APPENDIX C

ADVANTICA REPORT ON INITIAL TESTING OF SYNTHETIC PRODUCER GAS + MICRO-TURBINE

EXECUTIVE SUMMARY

A series of tests have been carried out to demonstrate the use of biogas as a fuel source for a commercially available microturbine system. Synthetic biogas of defined specification in compressed cylinders was successfully used to exclusively fuel a Capstone model 330 microturbine.

A procedure involving microturbine start-up with natural gas and switching over to 100% biogas was developed to surmount limitations imposed by the automated process controls. After switchover, the microturbine could run indefinitely on biogas. The highest generating capacity was $5kW_e$. This limit was imposed by the fuel delivery system.

A second series of tests have been carried out to assess the effectiveness of low-temperature combustion of biogas through catalyst modules developed for exhaust treatment of natural gas vehicles.

The catalyst modules proved to be highly effective at oxidation of the biogas fuel components with realistic biogas-air mixtures over a range pre-heat temperature that are easily attainable in microturbine systems via heat exchangers.

The CO oxidation is extremely effective, with combustion outlet CO levels at least as low as those present in ambient air. More than 95% of the biogas methane component was combusted at a fuel-air mixture pre-heat temperature of 260 °C.

The catalyst modules were capable of oxidising at least 5.25 kW net energy input. Further tests would be required to determine an upper limit to this performance.

The catalyst combustion tests enable additional options to utilise biogas as a microturbine fuel, should there be unforeseen complications in the direct fuelling of the microturbine with biogas. They also point to an innovative future configuration for the use of low CV fuels in microturbine systems.

The success of both test series represents a major achievement in the field of biogas fuel usage and can be built upon to significantly enhance opportunities for the marketing and deployment of the technologies on a worldwide basis.

CONTENTS

1. Introduction

Biomass Engineering Ltd. have developed systems to generate fuel gases of stable and repeatable specification from the heat treatment of renewable biomass fuel sources such as willow, waste-wood and forestry residues. This gas is termed biogas in this report, and has the further benefit of very low levels of ash and tar. This is significant, in that these components have been cited as obstacles to the use of biogas in many combustion systems and especially as fuel for microturbines. The ability to generate electricity in remote areas with no utility connection by fuelling microturbines with biogas generated from locally available biomass would substantially increase the potential market for biogas generators.

In the absence of a commercially available microturbine unit specified to use biogas as the fuel source, Advantica Technologies Ltd. and Biomass Engineering Ltd. were contracted by the Department of Trade and Industry (DTI) to investigate the feasibility of using such fuel in a microturbine.

This report presents the results of that study carried out by Advantica Technologies Ltd. (termed Advantica for the remainder of this report)

2. BIOGAS Specification

A specification for the trial biogas was supplied by Biomass Engineering Ltd. as shown in

Table 18, together with key calculated properties.

Species	*fraction (v/v)*	Unit
Methane	2.3	%
Carbon Dioxide	14.0	%
Carbon Monoxide	17.5	%
Hydrogen	17.6	%
Nitrogen	48.6	%
Derived Properties	Value	Unit
Calorific Value (Gross†)	5.094	MJ/m^3 at STP
Calorific Value (Net†)	4.676	MJ/Nm^3 at STP
Calorific Value (Gross†)	4.829	MJ/m^3 at NTP*
Calorific Value (Net†)	4.433	MJ/Nm^3 at NTP
Average molecular weight	25.745	gm/mol
Notes		

† Calculated using Advantica-authored gas properties program, GasVLE Net values are more appropriate, as the gross values assumed combustion product water condensation, which is not achievable in a microturbine system * NTP ias as STP but T=15°C (283K) Rotameters are often calibrated for gas delivery at NTP

Table 18: Composition of Test Biogas

Cylinders and cylinder packs of gas made up to this specification were supplied to Advantica by Air Products to carry out the trials. This is termed "synthetic biogas" in the remainder of this report. Cylinders of methane were also obtained to decommission the Capstone Microturbine prior to the main tests.

3. Microturbine hardware

Advantica investigated potential microturbine systems for trials with biogas and synthetic biogas. A research system was considered, but later discounted due to technical running issues. Two commercial systems were then considered:

? Bowman (model TG50)
? Capstone Microturbine (model 330)

The Capstone was chosen over the Bowman for the ability to control several aspects of the microturbine operation, particularly the ability to enable variable and low-peak electricity generation demand via remote software control. This was important from the standpoint of managing the demand for fuel in a trial system.

The Capstone model had the following specifications:

? Variable electrical generation capability 5-30 kW.
? Max pressure inlet: 5 barg.
? Automated fuel intake valve opening with feedback provided by gas quality, gas pressure, burner and exhaust temperature sensor parameters and power demand.

3.1 Capstone Automated Start-up and Control Sequences

The Capstone design incorporated a user-friendly start-up procedure which was controlled via Windows PC software.

This software automated the following processes:

1 Checking fuel pressure prior to start
2 Spinning up of the turbine blades using power source
3 Initial fuel injection and ignition
4 Increasing to acceptable burner temperature range
5 Acceleration of rotor when acceptable conditions prevail.
6 Control of system power to match load to fuel delivery.

These control processes were designed and optimised for operation with fuel close to natural gas specifications, though there is a wider tolerance on this unit than is found on most natural gas appliances. However, the biogas and synthetic have a much lower CV than natural gas. For natural gas, the base value CV of 35.8 MJ/Nm^3, a factor of 8.08 greater than the biogas equivalent. Hence the software controls would be operating well outside their expected design parameters.

During stages 4-6, the PC software applies an algorithm to control the degree to which the main gas supply valve opens, with burner temperature and electrical generation sensor outputs being key input to the working of the process.

A feature of the Microturbine system is the main control valve, which is designed to make the system robust to variations in the pressure of the delivered natural gas. This feature is driven by an algorithm which notes the combustion temperature, as well as the fuel delivery pressure. The algorithm has a built-in “time constant” to prevent the system from over-reacting to short-term pressure fluctuations.

The feature means that the system is able to cope with fluctuations in natural gas supply, but is equally able to react to variations in the Calorific Value (CV) of the fuel.

A photograph of the Capstone Microturbine is shown in .

Figure 10: Capstone Microturbine in Advantica Test Cell 2

4. Microturbine Tests Conducted

Advantica had access to a number of purpose-built engine test cells at their Loughborough site. These were purpose-built facilities, which provided a safe environment to carry out engine tests such as the trials required. The Capstone Microturbine (referred to as the Microturbine in the remainder of this report) was located in Engine Test Cell 2, which enabled combustion product extraction and power loading for the generator by connection to the local grid via a G59 unit authorised by the local electricity distributor.

The cylinders containing the synthetic biogas were located beside the test cell, and a simple gas delivery system was constructed to enable fuel to be delivered via safety interlocks and filters to the Microturbine fuel inlet.

After Test 1, gas analysis units were incorporated into the system to provide information on gas species concentrations within the combustion stream outlet.

4.1 Test 1: 31st July 2002

4.1.1 Results

The Microturbine was successfully recommissioned using the bottled methane fuel, and was monitored with an upgraded version of the control software.

The fuel supply was then switched to the synthetic biogas and the test repeated.

The initial start-up sequence proceeded to stage 3, when the automatic fuel ignition system activated successfully, in a manner similar to that observed with natural gas fuel delivery.

This was a positive result, as it was not clear whether a burner assembly designed to operate with a high CV fuel such as natural gas would be able to sustain combustion with the synthetic biogas.

The burner temperature started to increase as for normal operation, but the system was unable to open the main fuel control valve sufficiently to enable power generation to start. At this point, the software triggered a fuel fault and the Microturbine closed down on an automated procedure.

Interpretation and Subsequent Modifications

The problem of the main fuel valve control dynamic range (termed valve headroom in the remainder of this report) and it's ability to keep the fuel supply within the required demand range was an issue that had been identified as a threat to the success of the study prior to test commencement, and it had been noted that it was possible to convert the Microturbine to low CV operation. This option had been investigated but would have imposed unacceptably long lead times prior to project commencement.

Since no flow measurement devices had been incorporated into the simple fuel delivery system, it was not possible to assess the flow rate demand prior to system shut down.

One option was to increase the pressure setting on the synthetic biogas regulator during the time that fuel demand was escalating, as the pressure drop down the fuel line was rapidly increasing as the Microturbine opened the main fuel valve control. However, it was also noted that the timescale over which the unit increased the fuel demand was of the order of a few seconds, and it was not felt practicable to manually effect such a pressure change in a controlled manner on such short timescales.

Another possibility was to address the existing system fit to a high CV fuel by starting up the system using bottled methane, and then gradually blending the fuel stream with successively higher fractions of synthetic biogas once stable operation had been achieved. This option was chosen as it was relatively straightforward to implement and achieve in appropriate timescales.

Accordingly, a blender unit was constructed which took fuel from both the methane and synthetic biogas bottles. The unit included choke valves to alter the relative amounts of fuel accepted from each bottle, and gas flow-meters (rotameters) installed to give a guide to the relative fuel mixture being achieved.

A photograph of the blender system after subsequent upgrading is shown in Figure 29.

Figure 29The rotameters available for the blender were of limited pressure specification[1]. Since this pressure would be exceeded, a risk assessment was carried out, and the rotameters were mounted in a mobile cabinet with a transparent cover. This acted as additional protection for operators, who were mandated to wear safety spectacles during operation of the blender. The blender unit was pressure protected by the inclusion of a pressure relief valve rated at 11.24 bar. To complete the risk assessment, a special static test as carried out to confirm that the system integrity was maintained up to a point where the relief operated. However, it should be noted that this may not indicate the performance in situations where extremely fast pressure variations might be present.

Test 2a & b: 16th August 2002

Results

Various parameters were logged by the control PC whilst conducting Test 2a and in all subsequent tests. The values of most relevance to this study are shown as a plot vs. time in Figure 11.

The red trace shows the turbine exhaust exit temperature. The green trace shows the extent to which the system was automatically governing the opening of the

[1] 2.1 barg with standard covers, 4.2 barg with replacement polycarbonate covers.

main fuel control valve during the run. Both the biogas regulator pressure and the methane supply throttle valves were adjusted to increase the biogas/methane ratio during the course of the run, and to establish which controls were most effective at achieving a transition from methane to mixtures high in biogas.

At various points during test when the flow rates were stable, hand logs were taken of the gas species concentrations in the combustion stream outlet. The times for these measurements were also recorded, and are shown as "Measurement Times" in Figure 11 and following similar figures. The data logged at those times is presented in Figure 12 and Figure 13, and equivalent figures in subsequent tests.

It can be seen from Figure 11 that there was a propensity for the system to oscillate at certain stages of the blender configuration. These oscillations inversely correlated with the changes in the turbine exit temperature. It is thought that these oscillations occur when the characteristic timescales of elements of the blender system coincide with the delays factored into the control algorithms programmed into the PC control program. Later analysis showed they occurred when the choke valves on the methane delivery line were over-restricted. At this point, these oscillations were difficult to control as the control PC was physically separated from the gas blending controls.

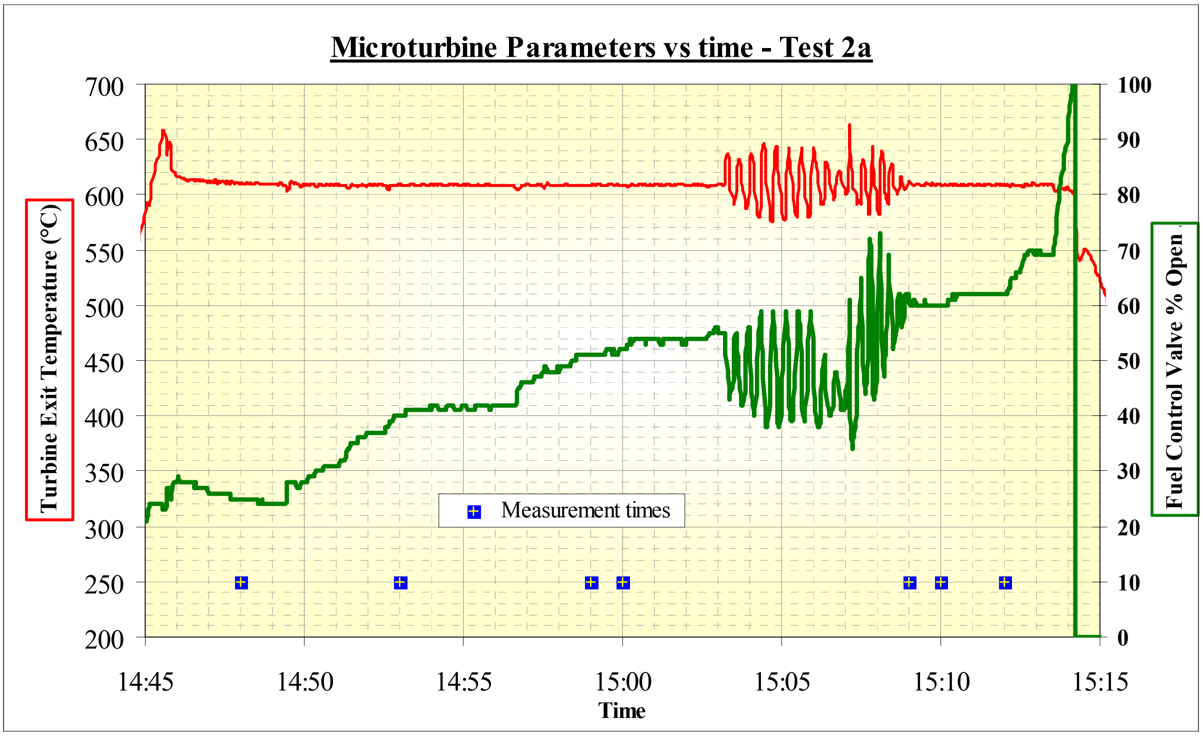


Figure 11: Logged Microturbine Parameters During Test 2a

The values read from the rotameters at intervals were converted from the calibrated air-equivalence values given by the rotameter scales to those relevant for the fuel in the lines via a spreadsheet, and were plotted vs. the fuel control valve opening fraction for each measurement set recorded. Figure 12 shows the plot for Test 2a. The spreadsheet also performed an energy analysis on the fuel streams, yielding biogas energy fraction and the biogas/methane energy ratio, which is shown in Figure 13.

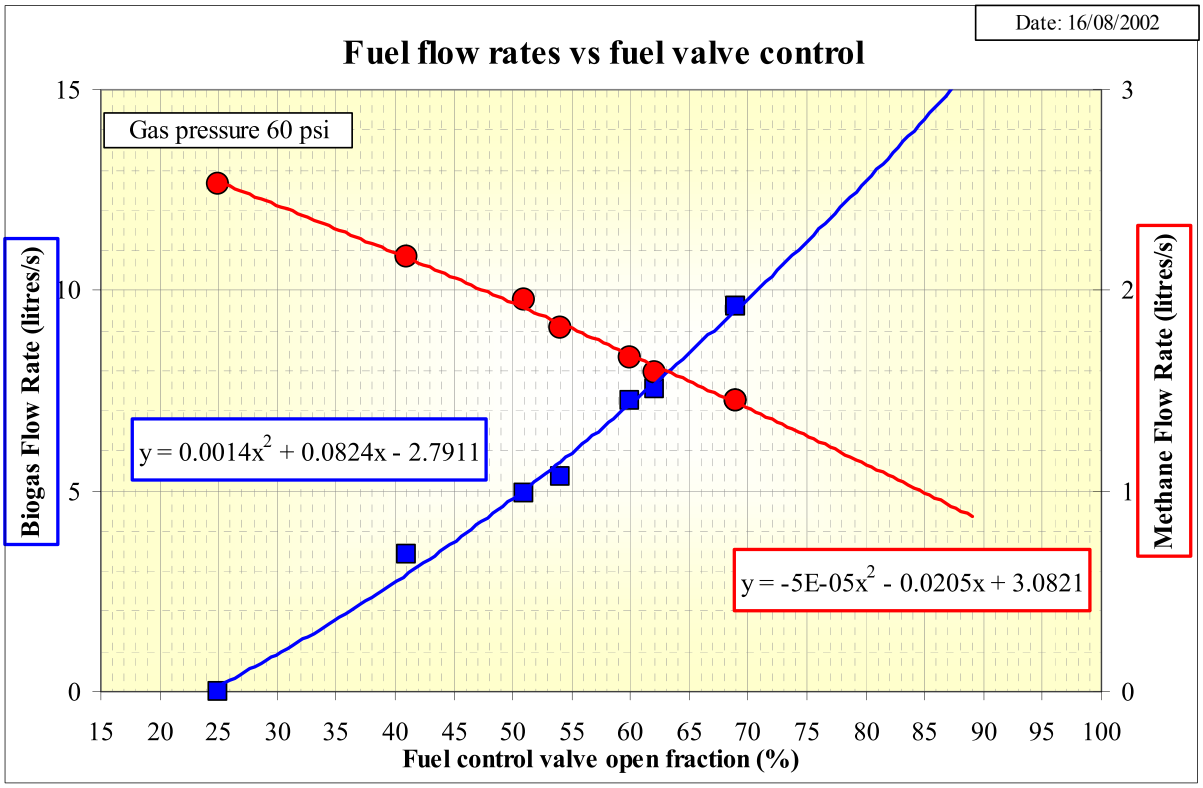


Figure 12: Fuel Volume Flow Rates in Test 2a

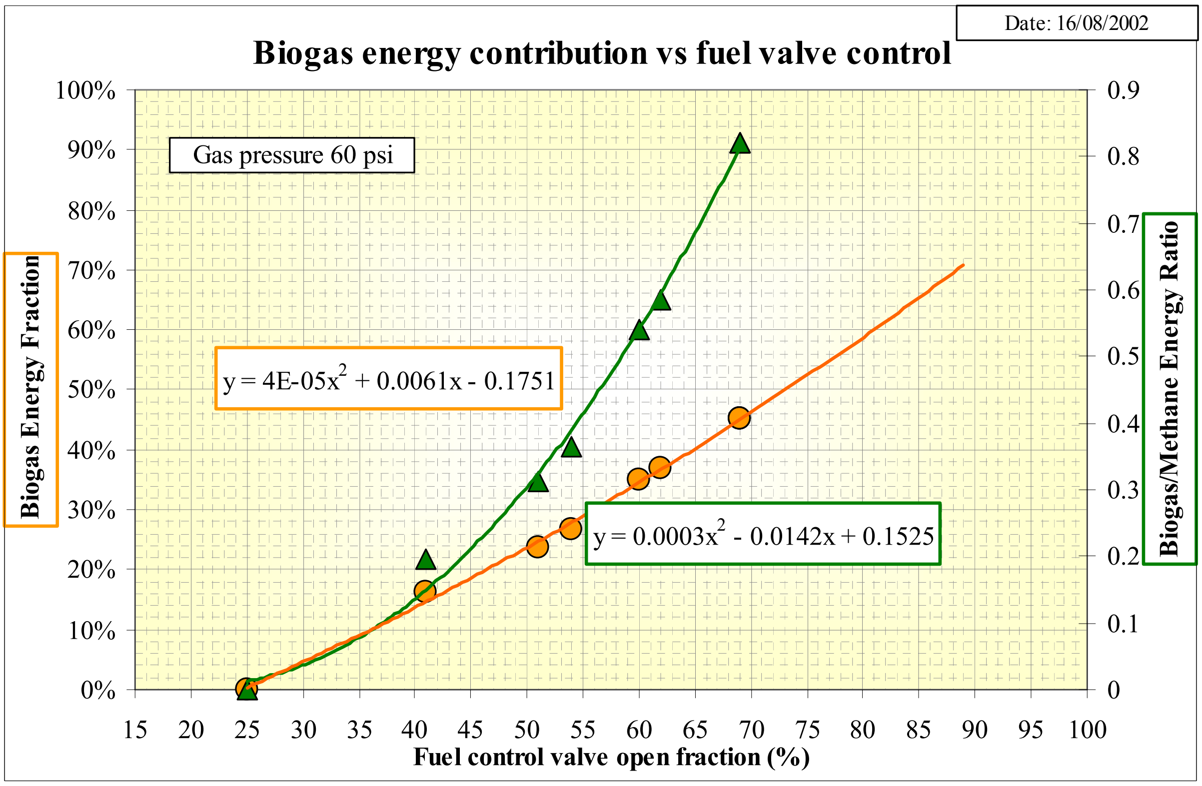


Figure 13: Fuel Energy Balance Analysis in Test 2a

A second test (Test 2b) was subsequently carried out, which restricted the methane delivery line more strongly. However, it was found that the flow-tube mounted in the methane line rotameter was too insensitive, and most readings were off the bottom of the scale. Hence no analysis was carried out for Test 2b.

Interpretation and Subsequent Modifications

The failure of the Test 2b to measure methane flow rates led to changing the methane fuel rotameter for a more sensitive unit, and the tests were repeated.

Also, the Capstone control PC was relocated to operate next to the blender controls. This gave better feedback to the operator on the effect on the system of operating the various blender controls.

Test 3: 20th August 2002

Results

In Test 3, some oscillation of the system occurred at one stage of the test, though this was corrected by adjustment of several controls in tandem[2].

A similar analysis was carried out as for Test 2, with figures presented in the same format.

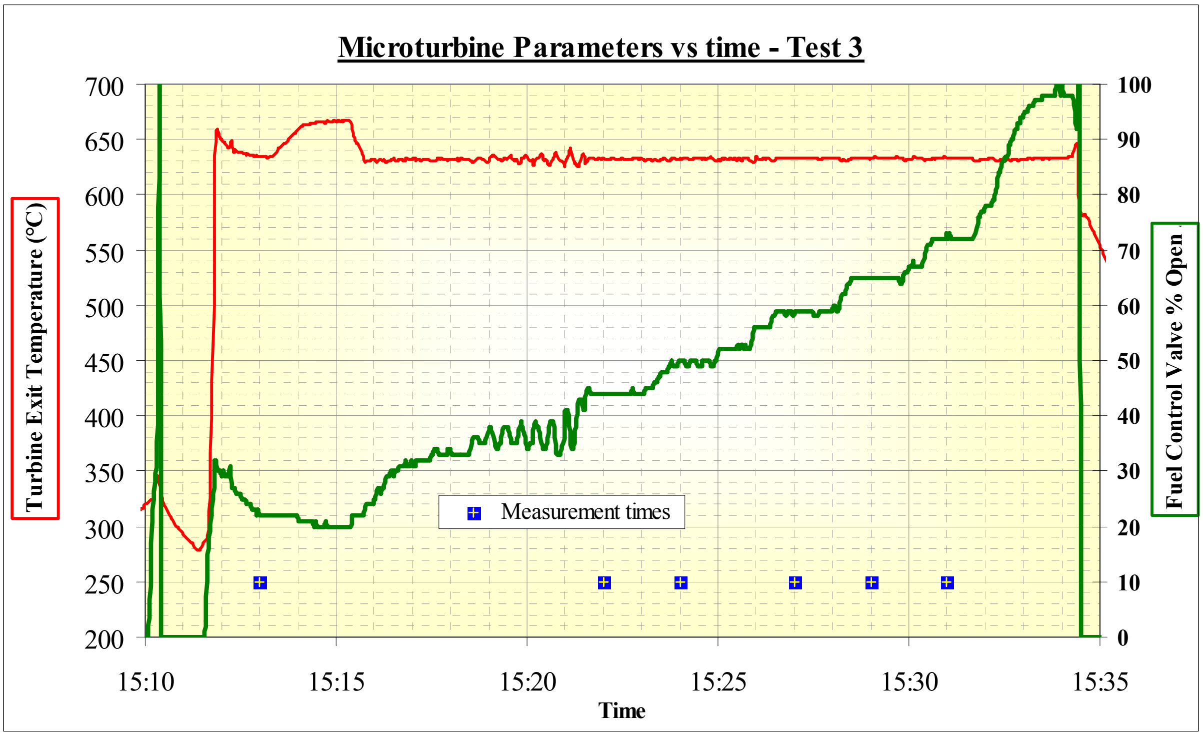


Figure 14: Logged Microturbine Parameters During Test 3

A higher fraction of biogas energy delivery to the system was achieved (70%) before the cylinder of synthetic biogas became depleted and the system shut down on a fuel fault failure.

[2] Details were not recorded at this stage but were noted and detailed in later tests.

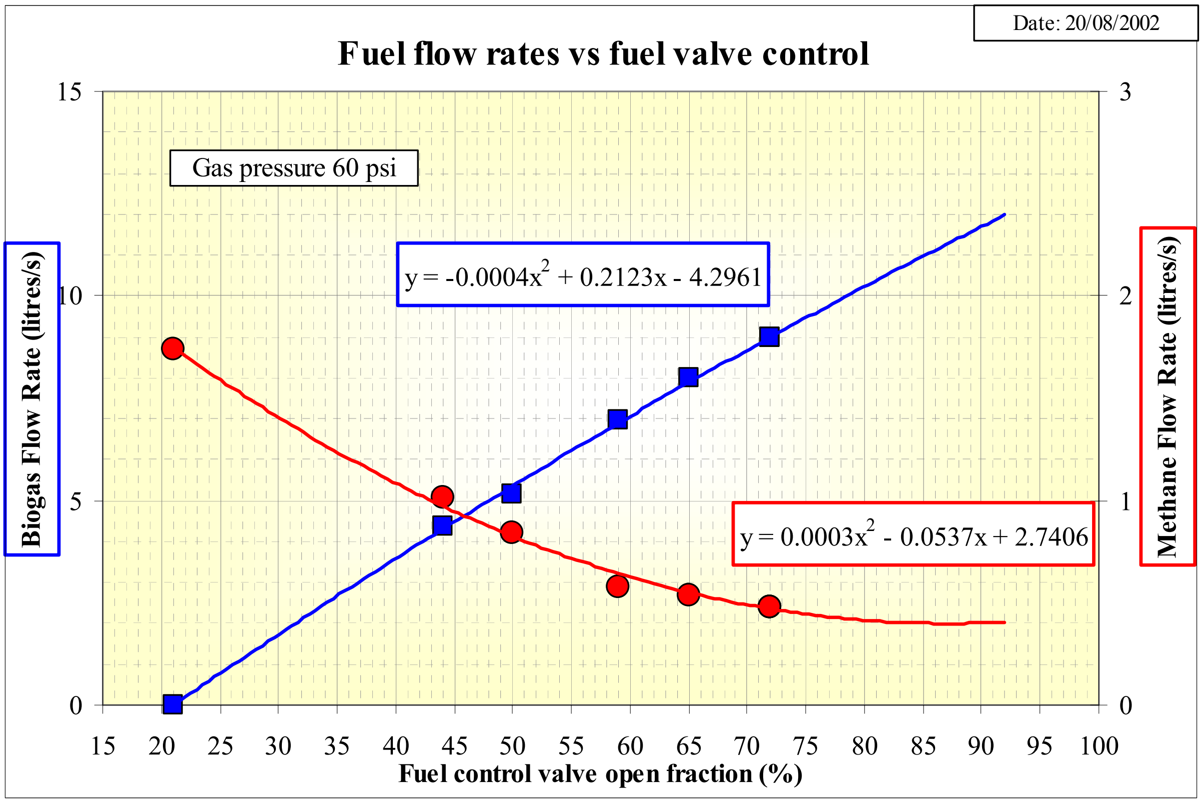


Figure 15: Fuel Volume Flow Rates in Test 3

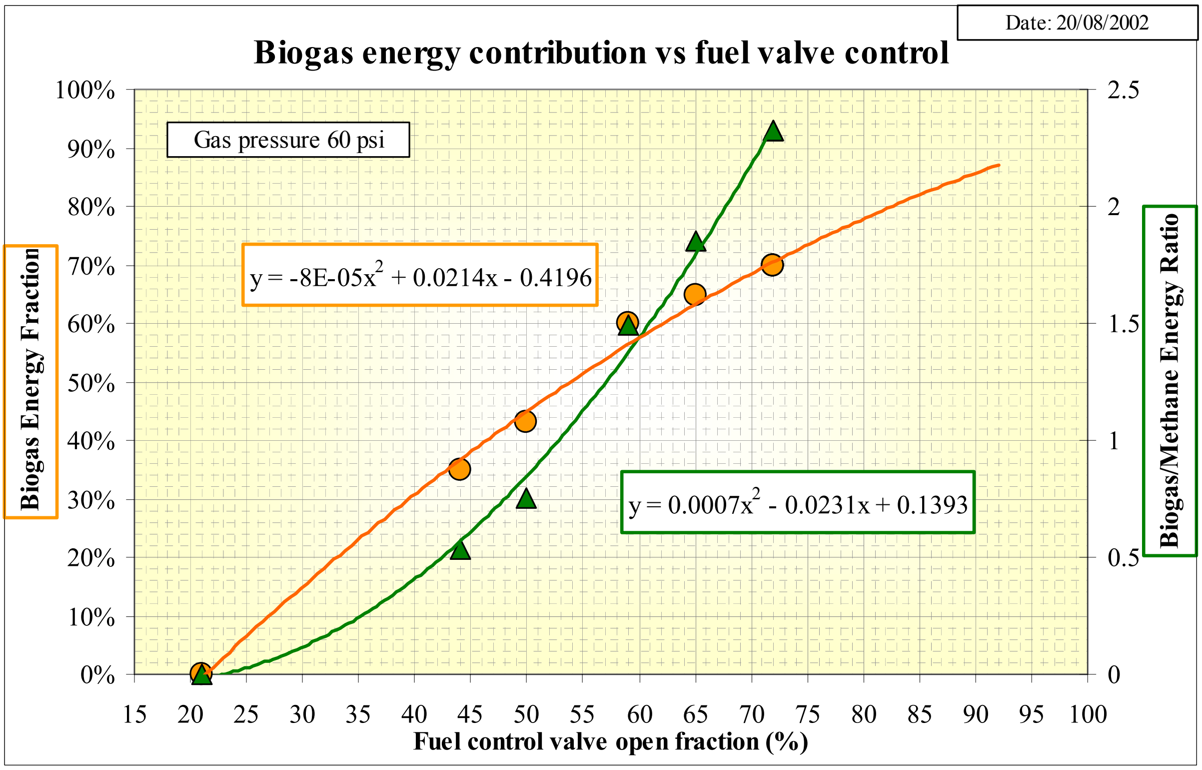


Figure 16: Fuel Energy Balance Analysis in Test 3

Interpretation and Subsequent Modifications

The run time available for a single cylinder of synthetic biogas was limiting the test run time available prior to system shut down. A multiple cylinder pack (11 cylinders) of synthetic biogas was installed as the fuel delivery source prior to Test 4.

Test 4: 2nd September 2002

A Land Lancom Series II portable gas analyser was deployed prior to this test to monitor CO, CO_2 and NOx in the Microturbine combustion stream outlet.

A lower initial pressure of 30 psi was set on the methane regulator during the Microturbine start-up phase.

Reduction in the methane delivered to the Microturbine in the initial stages was effected by throttling the gate-valves in the delivery line to the blender. Beyond the fuel control valve opening of 90%, the synthetic biogas regulator pressure was increased.

Results

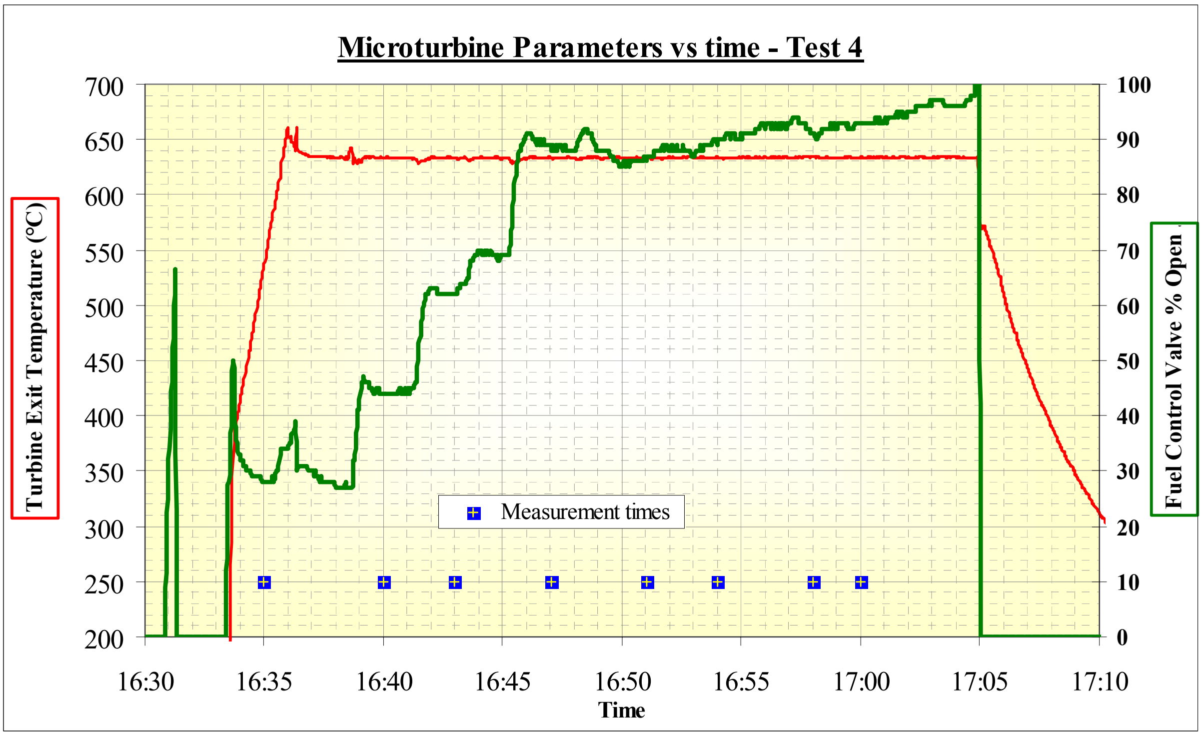


Figure 17: Logged Microturbine Parameters During Test 4

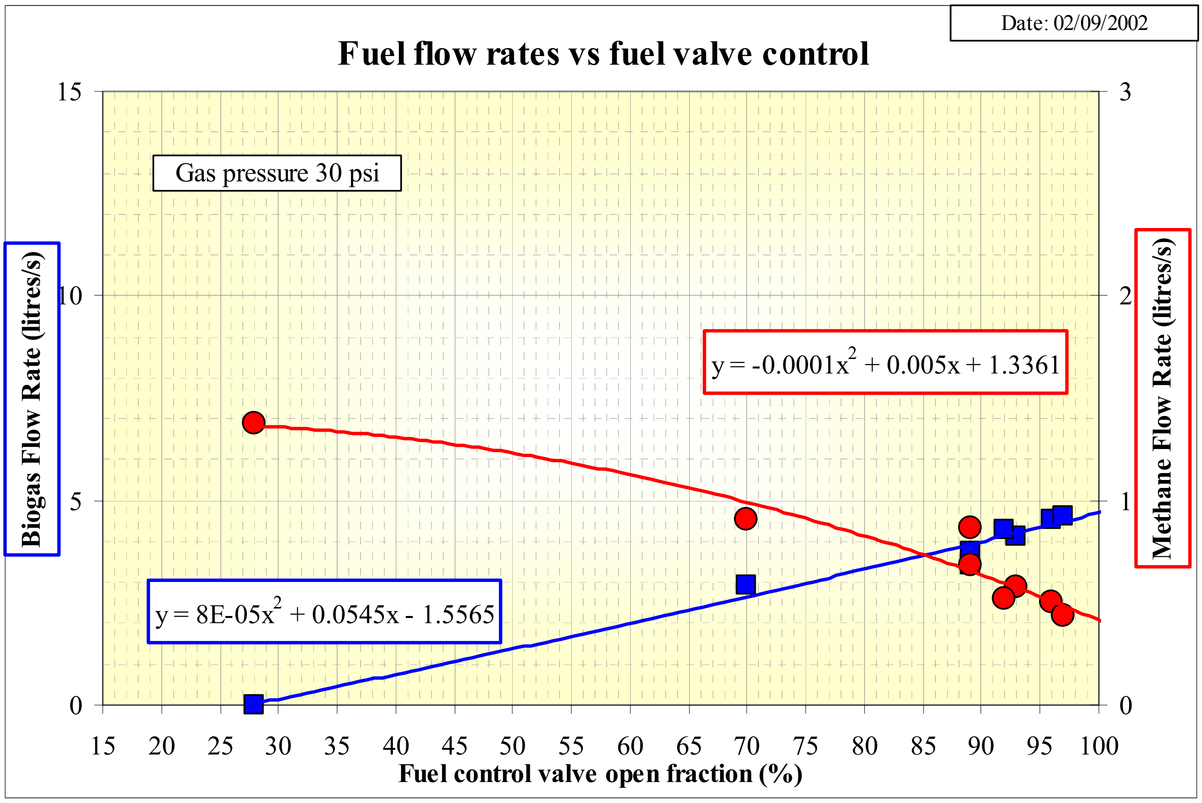


Figure 18: Fuel Volume Flow Rates in Test 4

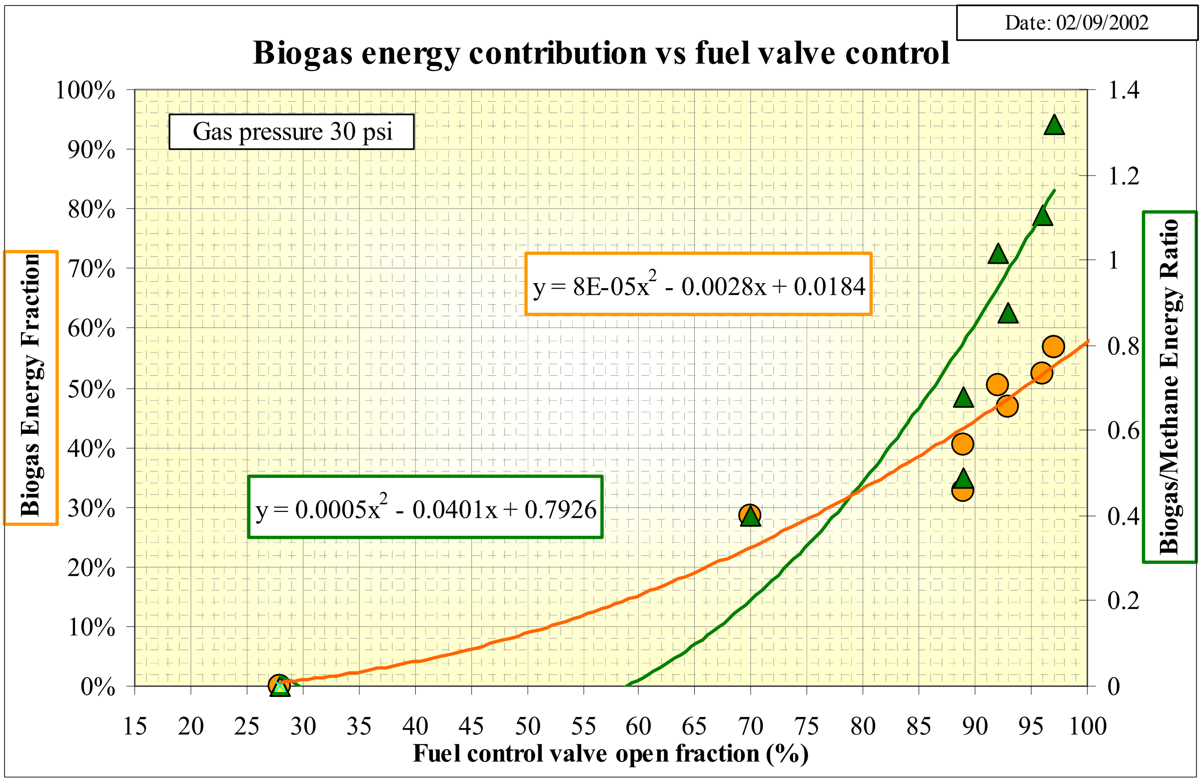


Figure 19: Fuel Energy Balance Analysis in Test 4

Interpretation and Subsequent Modifications

The biogas energy fraction achieved prior to system shut down was lower than for Test 3. Hence the methane regulator pressure was set higher for the next test at start-up.

Test 5: 3rd September 2002

The methane regulator pressure was set to 80 psi prior to the Microturbine start-up.

The synthetic biogas flow was increased by raising the biogas regulator pressure until the main fuel control valve was approximately 60% open. The methane delivery gate valves were then choked until the valve was approximately 90% open, after which the biogas regulator pressure was further raised. This resulted in the fuel valve slightly closing, so the methane gate valve was choked more, via a very small adjustment. This caused the fuel valve to fully open and shut down the Microturbine.

As the fuel control valve shut, the pressure relief valve on the gas delivery system operated.

Results

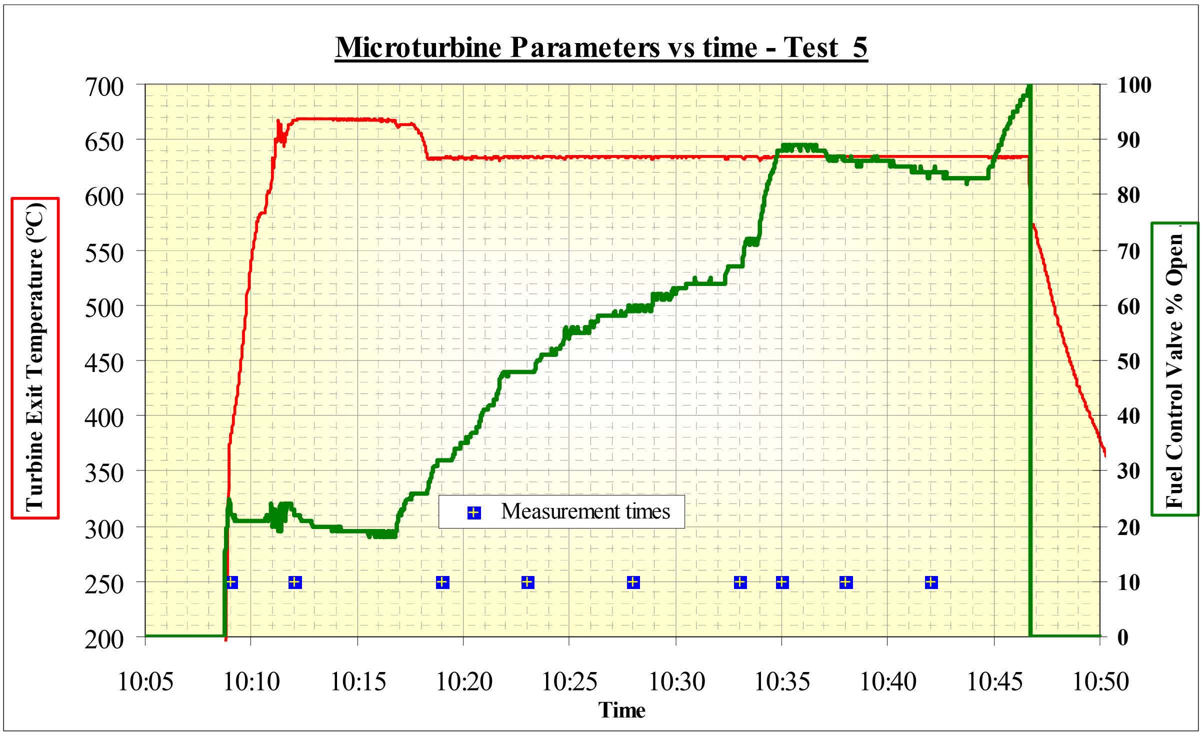


Figure 20: Logged Microturbine Parameters During Test 5

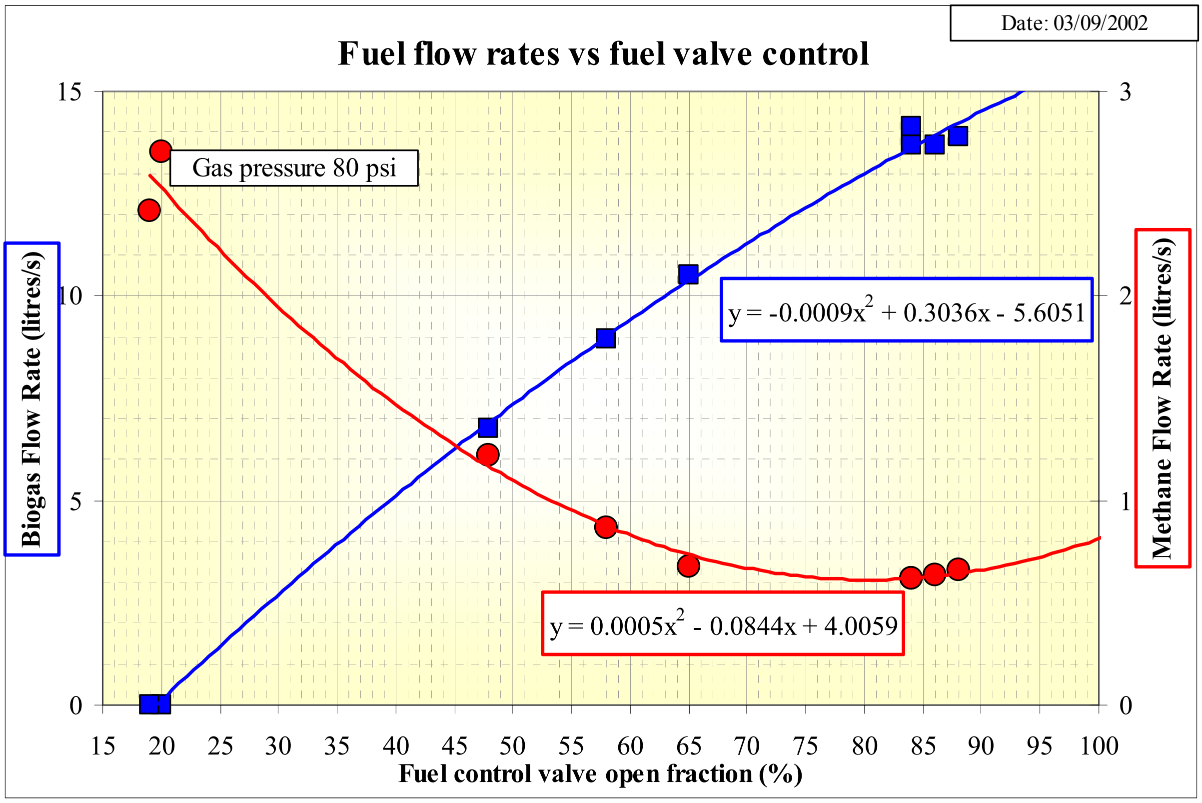


Figure 21: Fuel Volume Flow Rates in Test 5

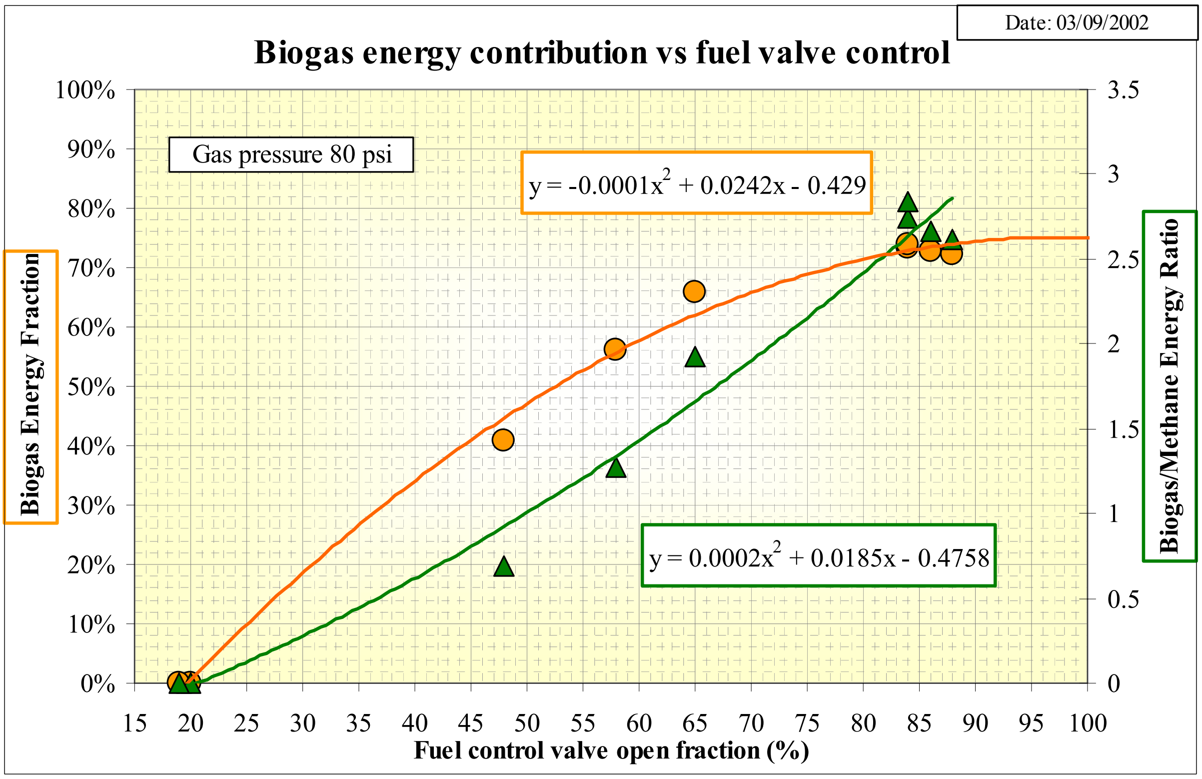


Figure 22: Fuel Energy Balance Analysis in Test 5

Interpretation and Subsequent Modifications

A similar fraction of biogas energy supplied to the Microturbine was achieved in Test 5, though the fuel-valve opening fraction was higher at approximately 85%, compared to less than 75% in Test 3. This meant that less headroom was available to the balance of biogas energy required, making this a less favourable configuration than that in Test 3.

The negative slope of the fuel-valve opening fraction exhibited between 10:35 and 10:45 when the biogas regulator pressure was being increased is noteworthy. The fact that the valve closes with increasing biogas pressure indicates that for each increment in biogas pressure, the energy content of the increased biogas flowing through the blender exceeded the energy content of the methane that was being reduced by the same increase in blender plenum chamber pressure, for this particular setting of the methane delivery throttle valves.

Unfortunately, the throttle valves were very non-linear in their action, and their position was not easily reproducible. This was exacerbated by the start sequence of the Microturbine requiring excess methane flow during start-up, requiring the throttle position to be "backed-off" during the firing sequence at the start of a new test.

The operation of the pressure relief valve on system shutdown was also noteworthy. This event indicated that the pressure on the biogas regulator was being increased to an undesirable level, by inducing rotameter pressure stress and a discharge of fuel with high carbon monoxide content.

It was noted that a pressure gauge mounted near the Microturbine fuel delivery point was reading approximately 1.5 bar lower than the values displayed on the regulator output gauge. This pressure drop through the ½ " pipework was reducing the ability of the blending system to deliver sufficient biogas to the Microturbine intake to enable running without methane content.

Hence it was decided to upgrade the bore of the biogas channel of the gas blender to 1" pipework, and to upgrade the post blender pipework to 1". This was achieved by incorporating 1" flexible hoses and bypassing the filter, regulator and pressure gauge which was previously fitted to the gas inlet of the Microturbine. These hoses were tested by pressurisation of the whole fuel delivery system until the pressure relief valve operated.

<u>Test 6a & b: 5th September 2002</u>

Two Tests were carried out on September 5th, Tests 6a & 6b, with the 1" delivery hose installed between the biogas pack and the blender unit, and 1" pipework from the blender unit to the rear of the Capstone Microturbine, omitting the narrow-bore pressure gauge and check regulator previously used.

Prior to this test, the methane cylinder regulator setting had been set to maximum (~5-5.2 barg) to ensure that some methane was still delivered through the blender, even at high biogas regulator settings. In Test 6a, the Microturbine unit shut down at a fuel inlet valve opening of only 48%, and prior to any stable readings being taken.

On investigation, it was concluded that the maximum inlet pressure (3.58 barg, 52 psig) to the Microturbine had been exceeded, causing it to trip and shutdown. This occurred because the pressure drop in the delivery pipes was now lower, with a resulting rise in pressure at the Microturbine head.

The methane pressure was lowered to 4.84 bar (70 psi) for Test 6b.

The biogas regulator was increased until the fuel control valve was open to approximately 50%, after which the methane throttle valve was used to reduce the methane flow rate. The test finished after an uncontrollable oscillation occurred and the system shut down.

Results

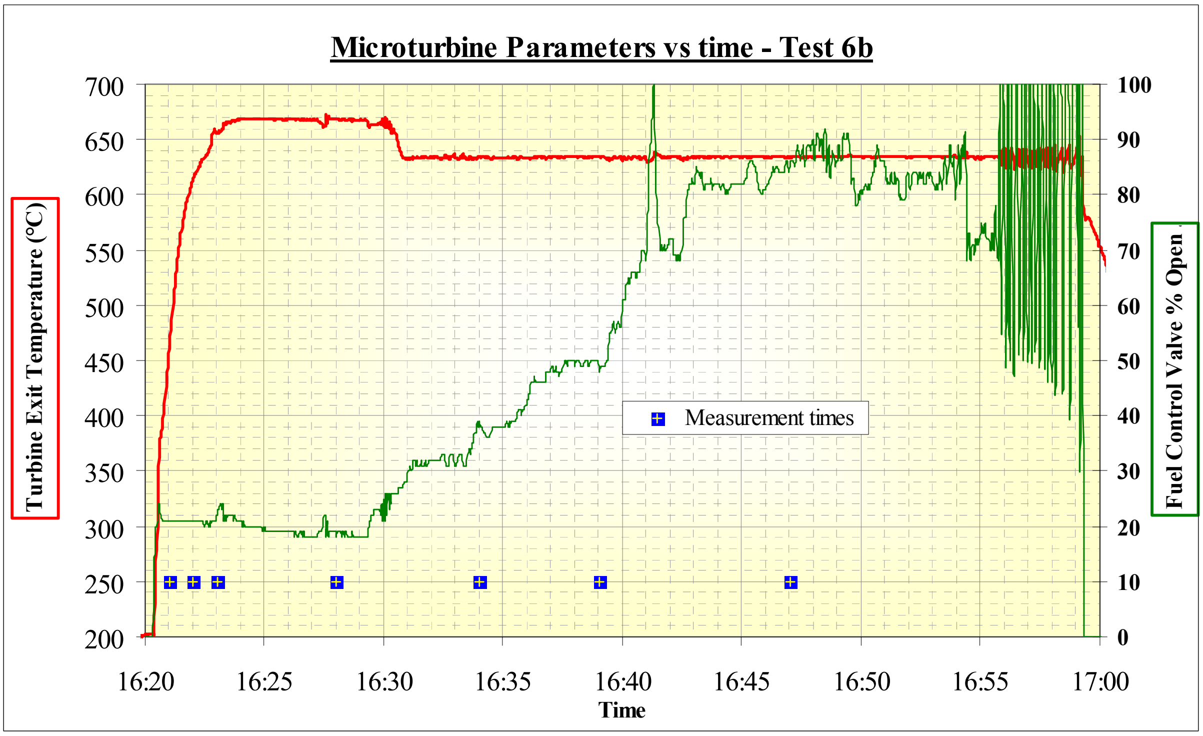


Figure 23: Logged Microturbine Parameters During Test 6b

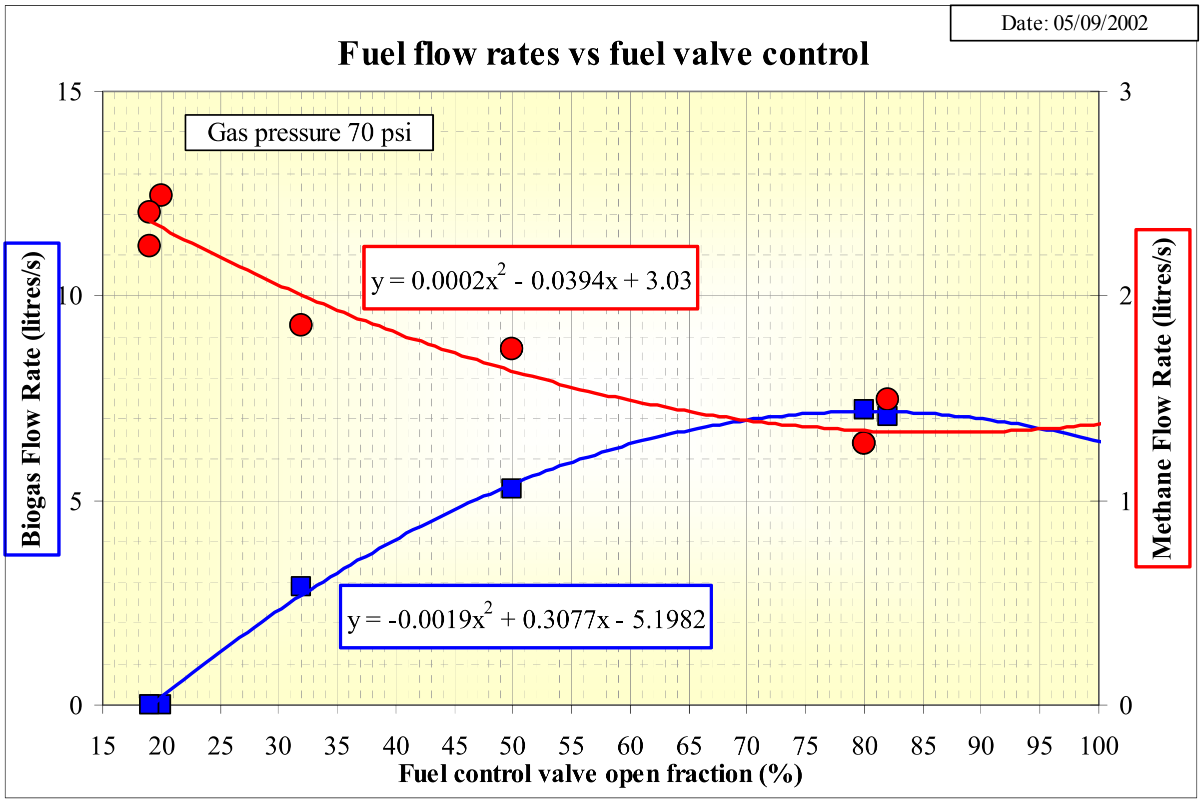


Figure 24: Fuel Volume Flow Rates in Test 6b

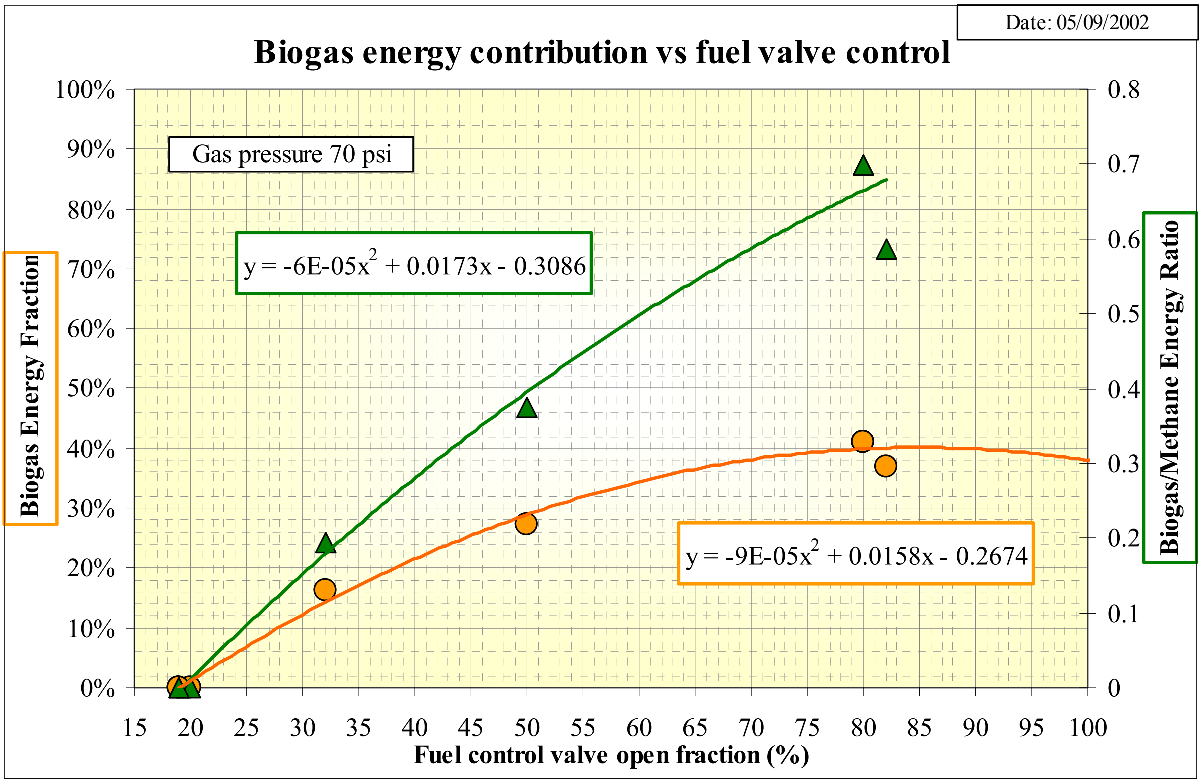


Figure 25: Fuel Energy Balance Analysis in Test 6b

Interpretation and Subsequent Modifications

The low biogas energy fraction achieved was disappointing, combined with the uncontrollable oscillation in the delivery pressure to the Microturbine by active interaction with the blender.

It was noted that the oscillatory behaviour had a degree of correlation with the extent to which the throttle valves had been closed to restrict the methane flow while maintaining a high delivery pressure from the methane regulator.

The conclusion was that the test should be repeated, but avoiding the need to choke the methane delivery line as much with the valves, and with a reduction in the methane regulator pressure.

Test 7: 6th September 2002

Accordingly, Test 7 was carried out with the methane regulator set at 5.1 barg and with the valve choking being applied to a lower value of fuel-valve opening fraction.

The biogas pressure was used to increase the biogas flow rate until a fuel-valve opening fraction of approximately 40% was observed.

The methane flow was then partially choked until a valve-opening fraction of 60% was noted. Then the biogas pressure regulator was increased until no discernable increase on biogas flow rate was observed.

At this point, the only ways to decrease the methane content were to either choke the methane line, which was contra-indicated by Test 6, or reduce the methane regulator pressure. The latter was tried, but after reaction by the fuel-control valve, an increase in the methane rotameter reading was observed. A small increase in the line choking, followed by a further reduction in the methane regulator pressure had similar effects, with a final extra methane line choke adjustment causing the system to trip out. As in Test 5, the pressure relief valve operated as the Microturbine fuel control valve closed on system shut down.

Results

The standard analysis was performed, plus additional interpretation of the energy balance analysis, which is presented in Figure 28.

The controls used to change the gas blending from pure methane to progressively more biogas is additionally shown in Figure 26.

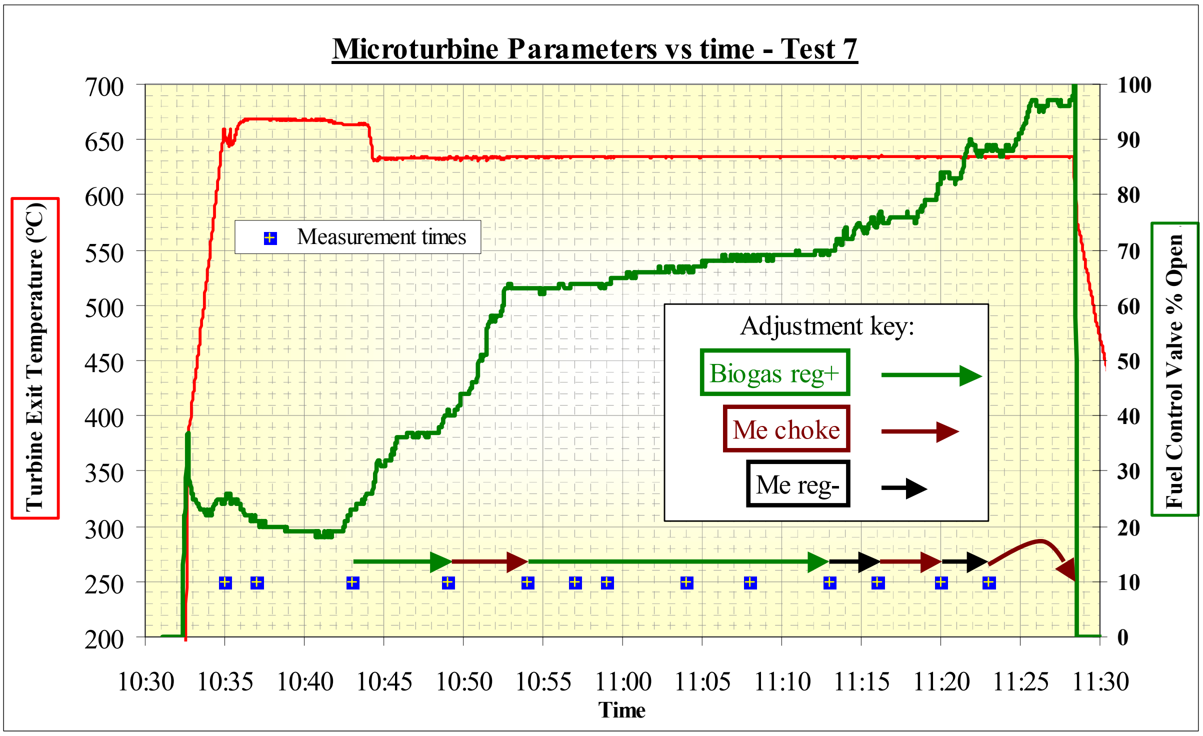


Figure 26: Logged Microturbine Parameters During Test 7

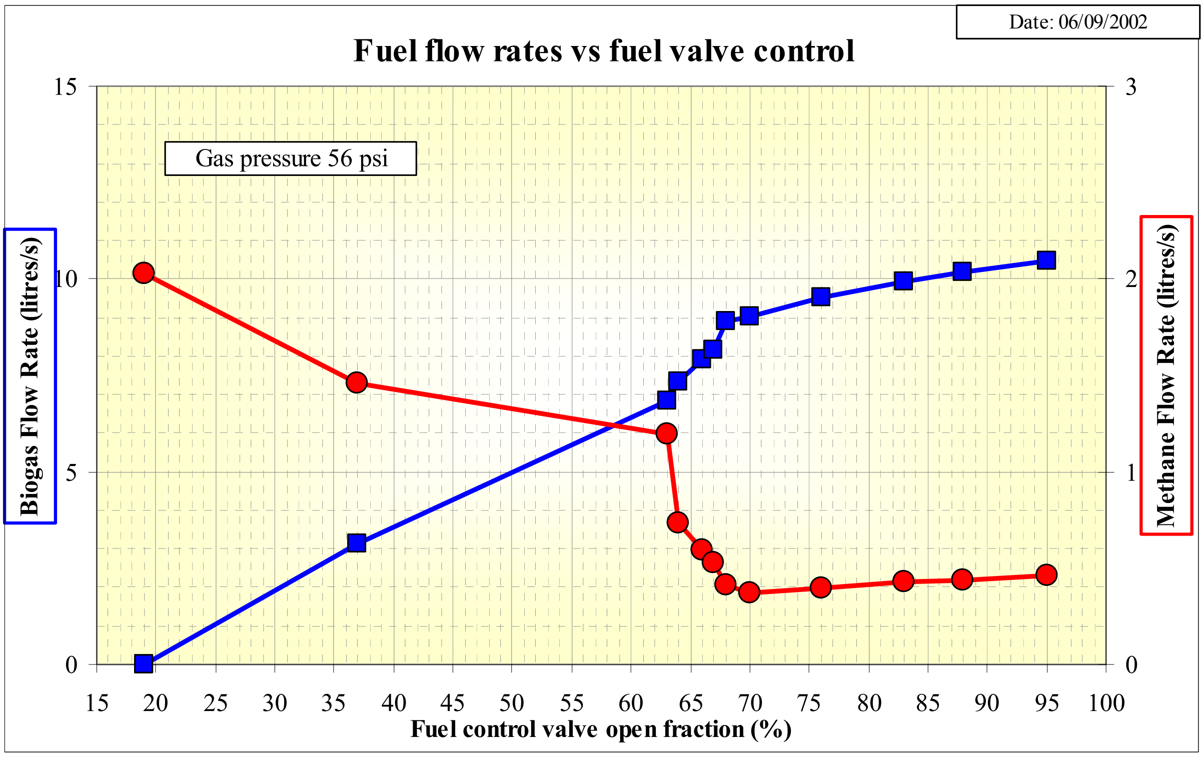


Figure 27: Fuel Volume Flow Rates in Test 7

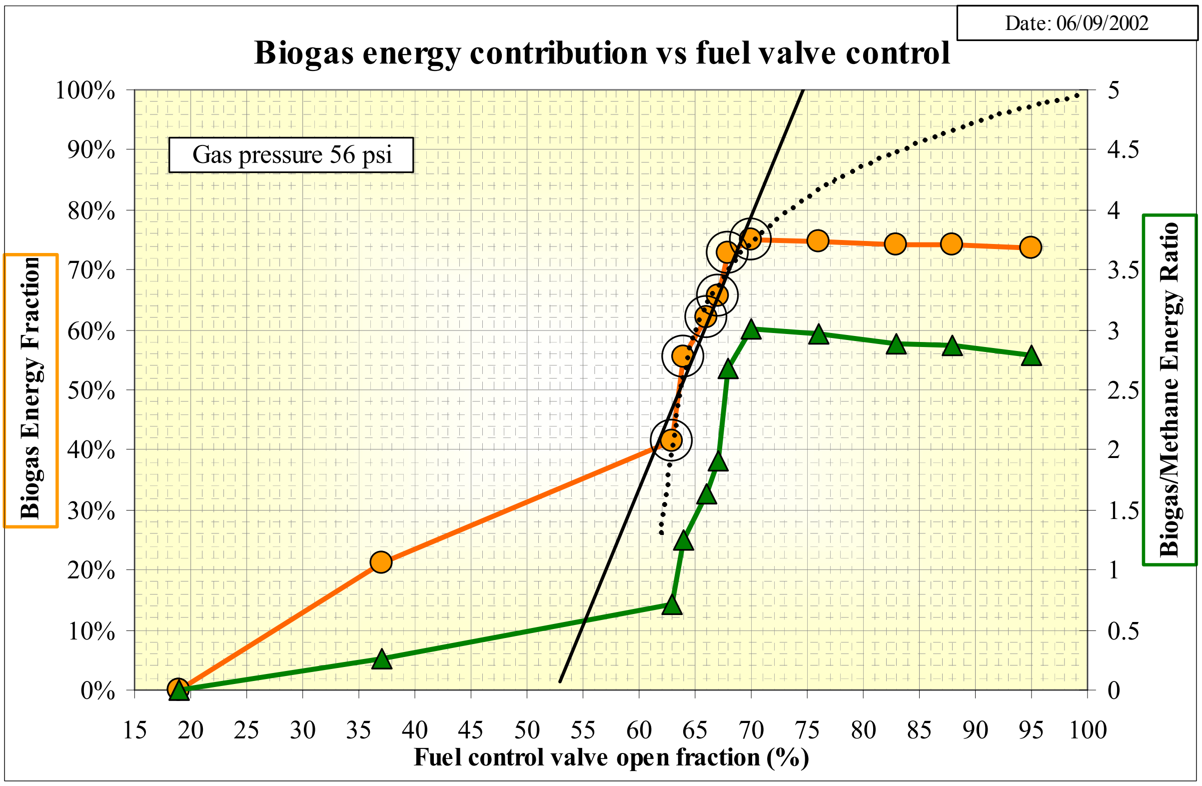


Figure 28: Fuel Energy Balance Analysis in Test 7

<u>Interpretation and Subsequent Modifications</u>

The slope of the fuel valve-opening fraction vs. time between 10:54 to 11:13 in Figure 26 is noteworthy. It can be seen that this period corresponded to a period when the synthetic biogas regulator pressure was being increased. Initially, the slope was small and positive, indicating that almost enough extra biogas energy was being delivered to the Microturbine by increased flow rate at each pressure increment to compensate for the energy lost by the reducing methane flow rate. This was occurring in the fuel-valve opening range of 60-70%, leaving considerable headroom for flow increase without the fuel inlet valve "topping out".

During the latter stage of this adjustment (times between 11:07 to 11:13), it can be seen that the system barely responded, with the fuel valve control opening only a further 2%. It was concluded that the biogas delivery system was at a maximum flow, and so the other mechanisms to increase the biogas/methane ratios were attempted. Both methods actually decreased the ratio, with the fuel valve headroom diminishing throughout, eventually leading to system shutdown. Both Figure 27 and Figure 28 show that Test 7 varied markedly from previous tests.

The points corresponding to the period 10:54 to 11:13 when the biogas regulator pressure was being increased are circled in Figure 28. Additional analysis on those points indicate that a biogas energy fraction could have been reached with a fuel-valve open setting of as little as 75% (linear fit shown). A more conservative interpretation (the dotted line) also indicates that, had the biogas flow-rate continued to increase with the adjustment of the regulator, it is possible that the Microturbine would have run at 100% biogas with no methane input. After the test, the synthetic biogas regulator was examined. It was noted that the bore of the outlet ¼" NPT fitting was considerably larger than the small hole which formed the exit from the regulator. It was concluded that the lack of system response during the latter part of the regulator adjustment had been correctly interpreted as the biogas delivery system reaching a maximum flow rate, with a choked flow regime[3]. Without changing the configuration, the only way to increase the flow rate delivered by the installed regulator would be to increase the total pressure within the cylinder pack, which was not an option.

An alternative method to increase the biogas flow delivery was to enable a second regulator to mount onto the cylinder pack. Components were ordered to fabricate a gas "tee" of appropriate pressure specification, enabling two regulators to access the pack. The second regulator was coupled to a 1" flexible hose, which was "teed" into the biogas delivery stream prior to the biogas rotameter, and included a further 1" non-return valve to protect the regulator from back-pressure from the other fuel delivery components.

A photograph of the blender system at this stage is shown in Figure 29 and the twin regulator configuration of the synthetic biogas cylinder pack is shown in Figure 30.

Figure 29: Gas blender unit after conversion to twin 1" hose biogas delivery &

[3] A choked flow regime occurs across any orifice when the ratio of the pressure upstream of the orifice divided by that on the downstream side is greater than a threshold value, usually taken to be 2. When this occurs, the flow rate is dependant only on the upstream pressure. In this instance, the upstream pressure could be taken as the cylinder pack pressure.

Figure 30: Synthetic biogas pack after conversion to twin regulator delivery

Test 8: 3rd October 2002

Test 7 was repeated with the dual-regulator cylinder pack configuration installed. It was found that the additional gas throughput enabled by the extra regulator was sufficient to allow all the methane flow to be choked off from the blender without the Microturbine going into shutdown mode. The unit generated 5 kW_e on a stable basis for more than two minutes, and showed no sign that it could not run indefinitely in this configuration, given adequate fuel supply. However, synthetic biogas inventory considerations necessitated shutdown after this time.

Results

During the period when the Microturbine was running exclusively on biogas fuel, the levels of NOx, CO and CO_2 were recorded using the Land Lancom Series II portable gas analyser. During the period they indicated concentrations of 2ppm NOx, CO between 50 and 80 ppm and CO_2 of 2.32 to 2.42 %.

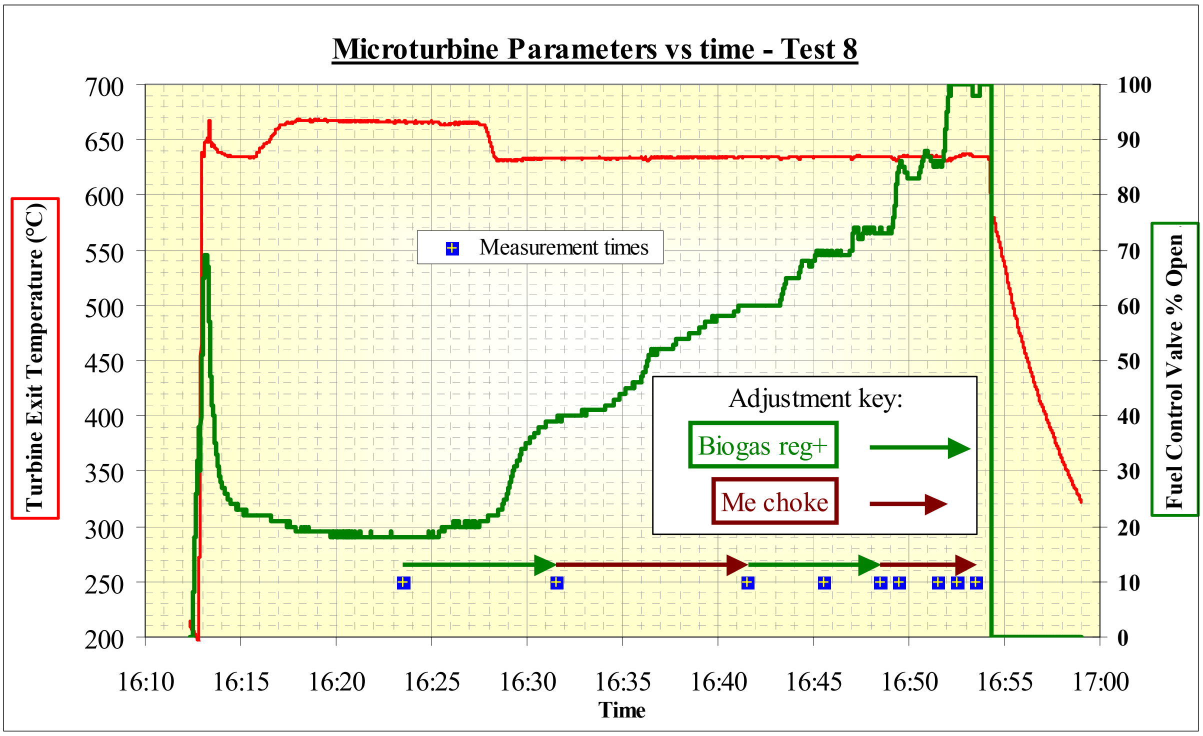


Figure 31: Logged Microturbine Parameters During Test 8

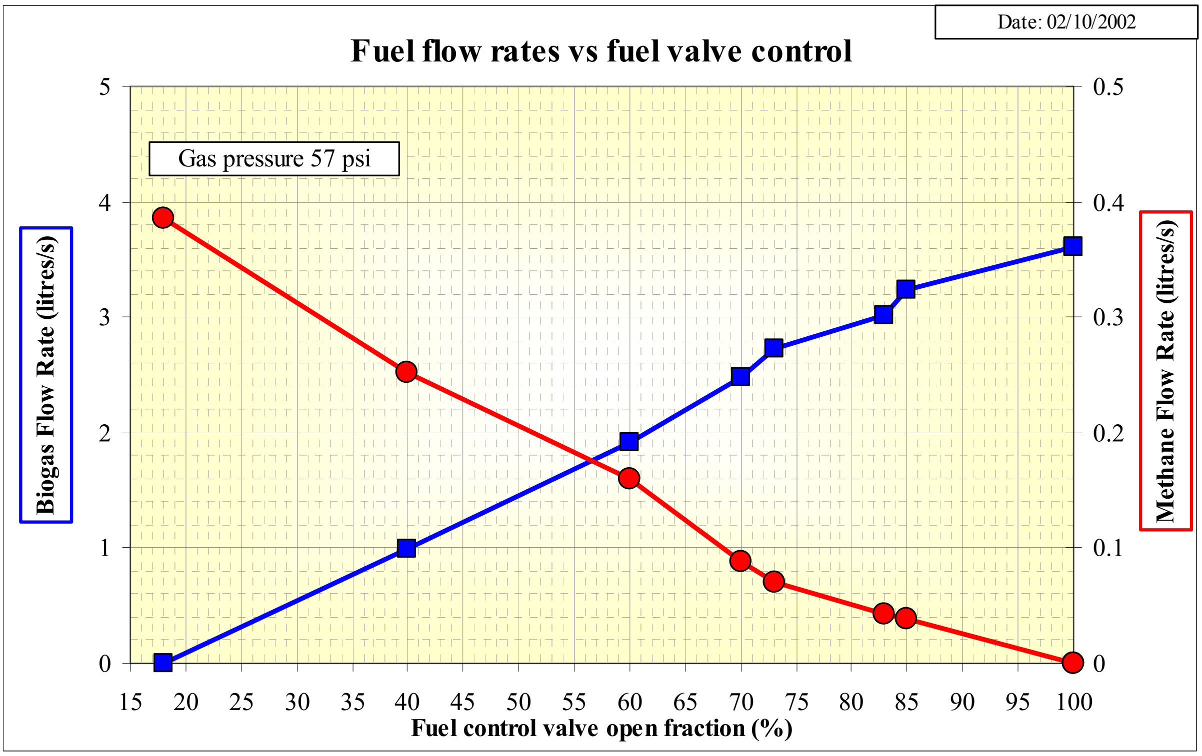


Figure 32: Fuel Volume Flow Rates in Test 8

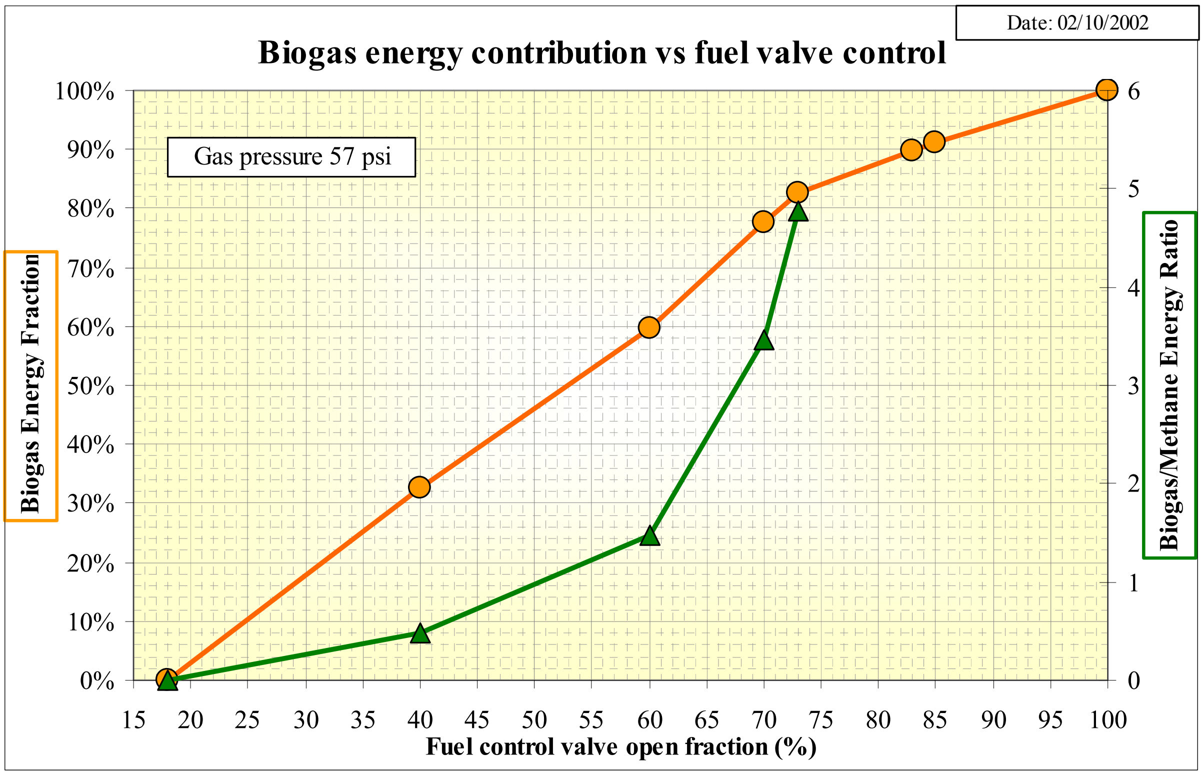


Figure 33: Fuel Energy Balance Analysis in Test 8

Interpretation and Subsequent Modifications

The flow rates are shown in Figure 32, and indicated that the Microturbine biogas fuel consumption rate was 3.60 litres/s under the test conditions of 57 psi and 5°C, which translates to an input power of 64.2 kW, using the calculated net[4] CV of 4.676 MJ/m^3 at standard temperature and pressure. For running on natural gas at a fully rated output of $29kW_e$, the ratio for total energy input to generated electrical power output is typically 3.8 - 4. This ratio would be expected to increase for lower values of electrical power generation due to parasitic losses. The value obtained for the synthetic biogas used is 12.8. This probably arises from a combination of reduced turbine efficiency from the reduced flame temperature within the combustion chamber, the low electrical demand extracted from the generator[5] and the system parameters being optimised for a very much greater CV fuel.

No further modifications to the fuel delivery system were made, but extra gas analysers were deployed to sample the composition of the combustion product stream emerging from the Microturbine. A Siemens Ultramat $22/O_2$ analyser was used to measure both CO and CO_2 concentrations. An ADC methane analyser was deployed to measure any unburned methane in the combustion stream[6], and a Servomex 1400 CO_2 analyser was deployed to monitor the fuel CO_2 concentration. The last two analysers were primarily deployed to characterise the fuel input and combustion output streams during the Catalytic Combustion Rig for the catalyst tests described in Section 0, which were being conducted after this test. However, they also provided data for Microturbine Test 9.

Following the success of the test, it was decided to retain the largest quantity of synthetic biogas left in the cylinder pack for the longest possible run, witnessed by Andrew Connor of Biomass Engineering.

<u>Demonstration Test 9: 9th October 2002</u>

Andrew Connor was able to attend at Advantica Loughborough to witness Test 9, which was essentially a repeat of Test 8, but with a longer duration of steady running, plus the addition of the gas analysers detailed in Section 0. The low gas inventory of the cylinder pack lead to the deployment of the second regulator to the last remaining single cylinder which remained charged to the full delivered pressure. This optimised the time available for steady running on biogas after the methane stream was finally shut off.

The test was carried out immediately following Catalyst Combustion Rig Test 8 which is reported in Section 0. The Microturbine test was run exclusively on the synthetic biogas in excess of 8 minutes. During this period, the fuel control valve opening was slowly rising because of the ongoing depletion of the cylinder pack inventory. So that some gas would be left for calibration tests, the biogas fuel flow was choked after this time, leading to automated system shutdown.

<u>Results</u>

During the witnessed test, the gas analysers monitoring combustion stream CO, CO_2 and methane were recorded with a data logger. Results are shown in Figure 37.

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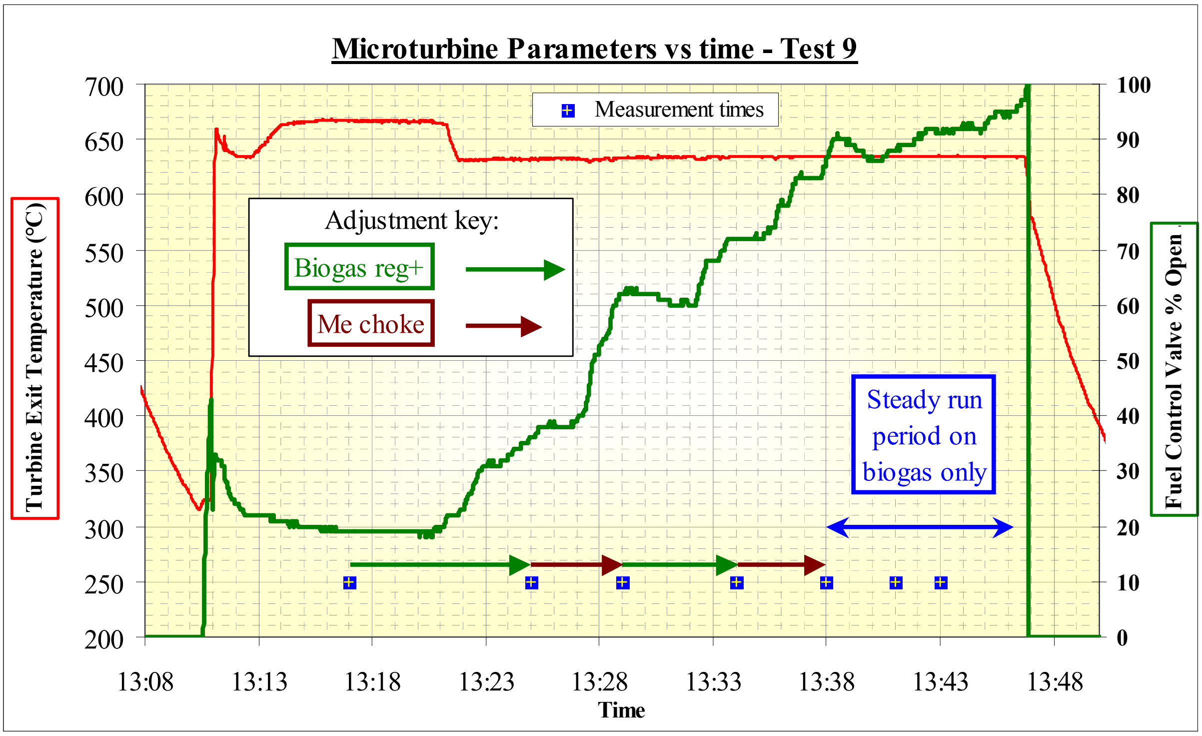
[4] The net value was used as the latent heat of vaporisation of the water content of the emitted combustion stream was not available to the microturbine.
[5] required to minimise the fuel delivery requirement to the Microturbine by regulated cylinder pack.
[6] This had been previously deployed to measure the composition of the exhaust species in the Microturbine tests.

When the Microturbine was running exclusively on biogas fuel, the levels of NOx, CO and CO_2 were recorded using the Land Lancom Series II portable gas analyser. During the period this indicated concentrations of 3 ppm NOx, 30 ppm CO and 2.00 % CO_2.

The time-logged combustion stream concentration data presented in Figure 37 was analysed during the periods shown[7], and indicated that unburned methane was present at 16 ppm (0.07% of the fuel input level), with 25ppm CO (0.014% of the fuel input level) in the combustion outlet, with no levels higher than 40 ppm after fuel ignition. The CO value was lower than many domestic appliances, and was very encouraging for a system not designed to handle low CV fuel with high CO content.

After applying the deduced post-test calibration factors to the logged data, the value for the combustion stream CO_2 concentration from the Siemens Ultramat 22/O_2 analyser was in good agreement with the Land Lancom Series II portable gas analyser (2.00 and 2.05 % respectively).

Figure 34: Logged Microturbine Parameters During Test 9



[7] Post-test calibration of the logged data indicated the following calibration constants needed to be applied to the presented data: Methane: 2.3256, Fuel CO_2; 1.135, Combustion CO_2; 1.0845. Applying these multipliers to the raw data led to excellent agreement between the analysers

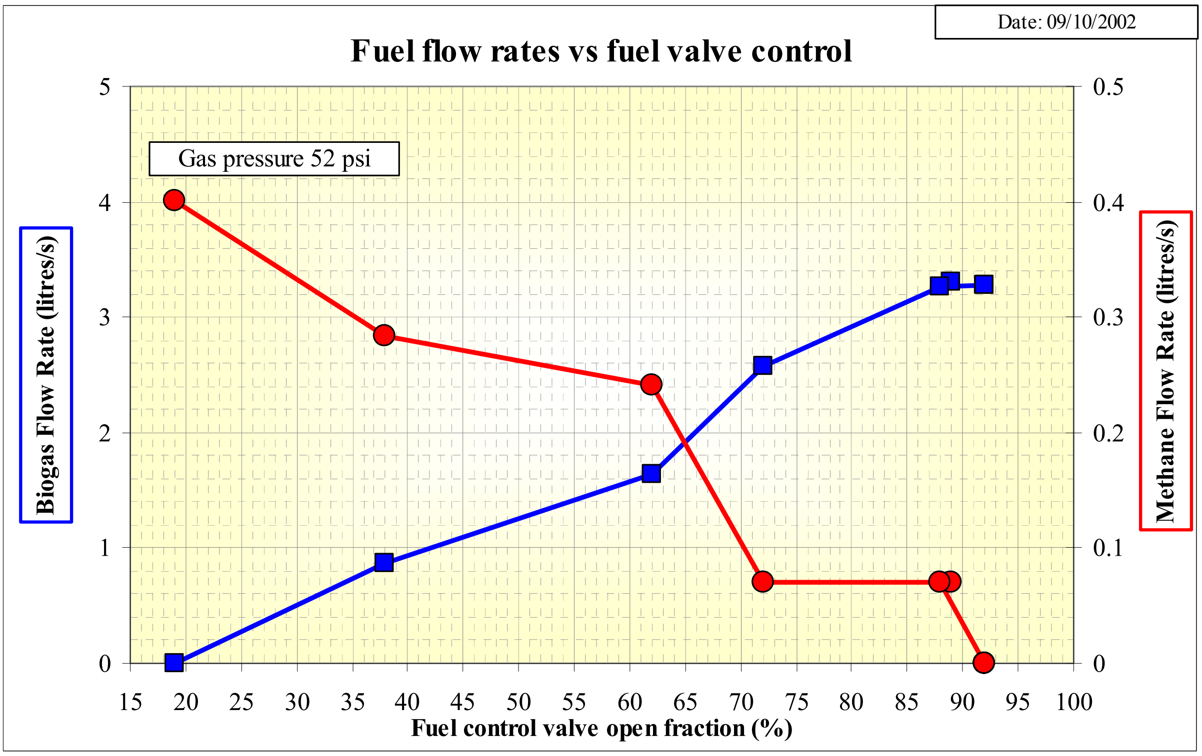


Figure 35: Fuel Volume Flow Rates in Test 9

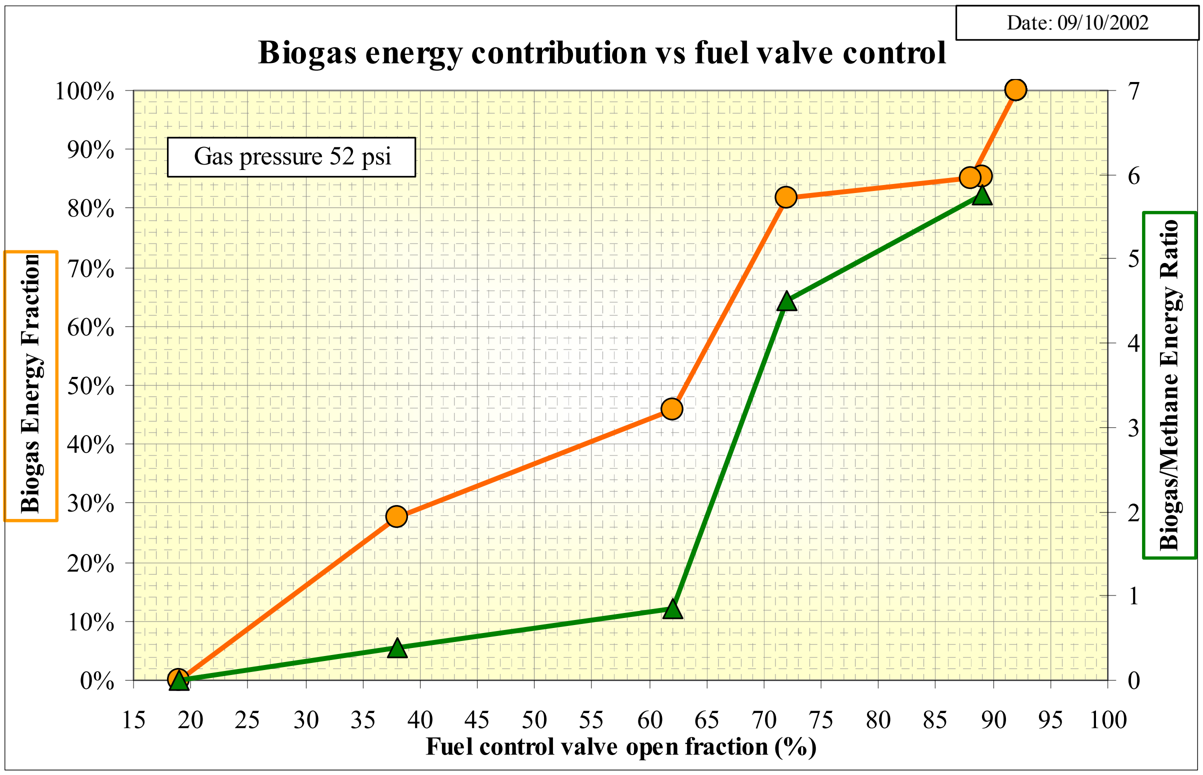


Figure 36: Fuel Energy Balance Analysis in Test 9

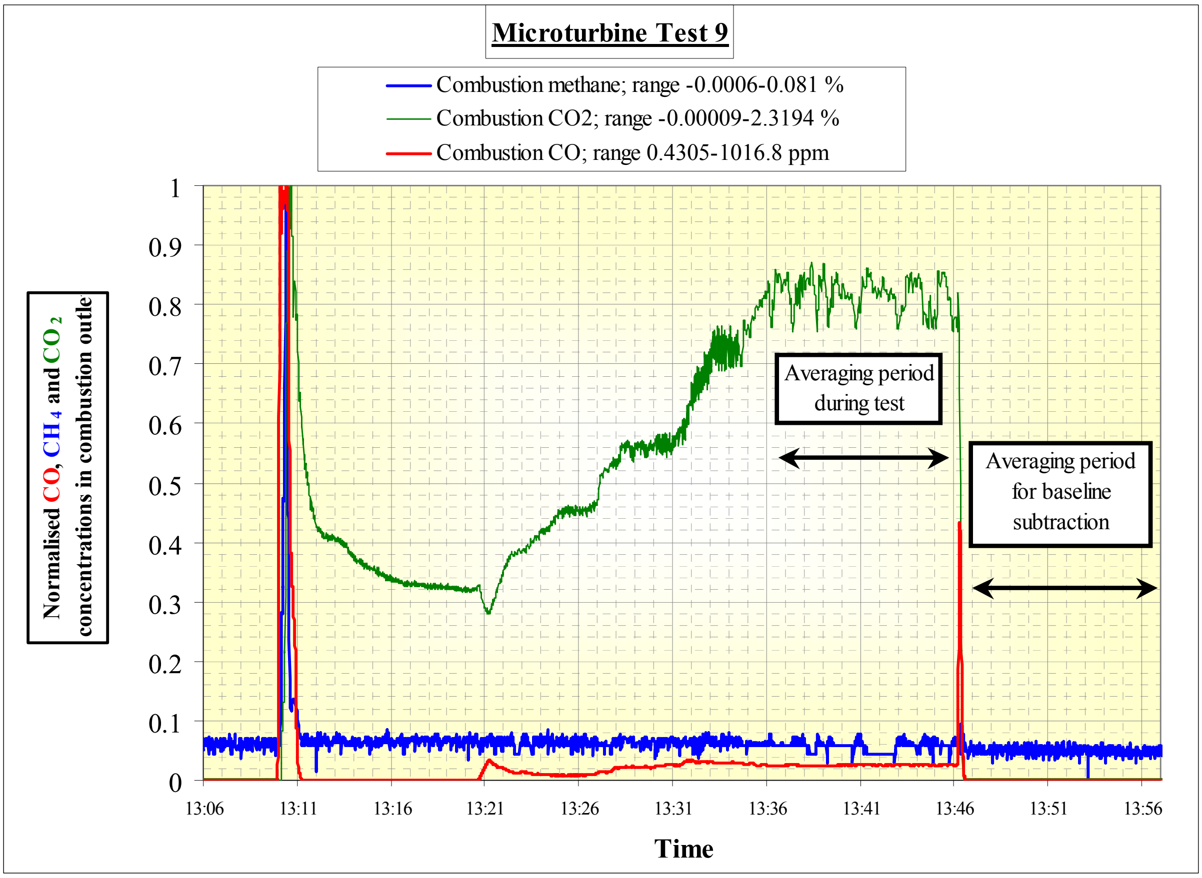


Figure 37: Gas species concentrations logged during Test 9

<u>Interpretation and overall Microturbine test conclusions</u>

The test affirmed the conclusion of Test 8 that the Microturbine is capable of running exclusively on the synthetic biogas fuel, provided that sufficient flow is made available for the unit to operate for the requested electrical generation demand.

The blender configuration used in these tests was a workaround to enable the Microturbine control systems to operate within their programmed parameters, whilst gradually switching over the fuel stream from natural gas to 100% biogas.

The speed with which the fuel changeover could be accomplished was a function of the time constants built into the control software, which may in turn reflect inherent characteristic times of the mechanical hardware.

It is possible that direct firing of the system could be achieved if a higher transient biogas flow rate was deliverable, which would also enable higher electrical generation from the Microturbine. These possibilities remain untested.

Catalytic Combustion Rig

An existing catalytic combustion test rig was adapted to investigate combustion of the synthetic biogas at low temperatures.

A schematic of the rig is shown in Figure 38.

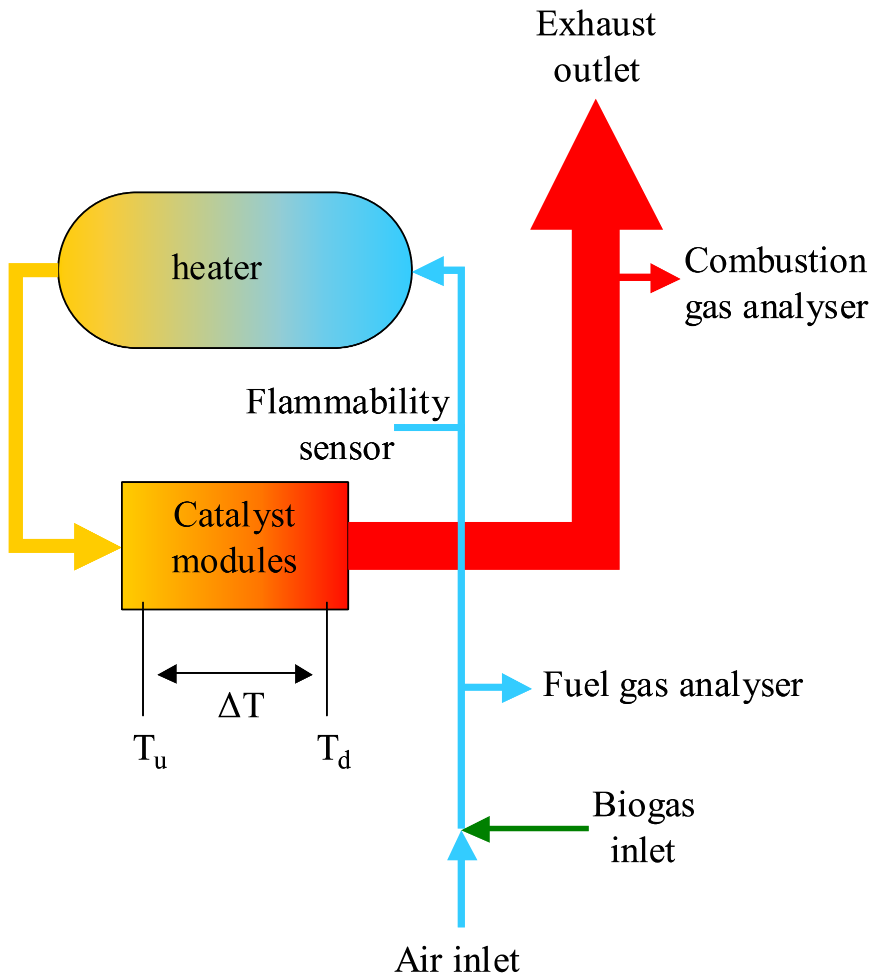


Figure 38: Side elevation schematic of catalytic combustion test rig

The synthetic biogas was fed into a stream of compressed air at a ratio approximating to an ideal of 10.9:1 air:biogas by volume. The ideal ratio was calculated to be the ideal mixture for biogas of this specification, whilst maintaining the same mass flow rate per kW generated through the Microturbine when fuelled with natural gas. After mixing, a sample was drawn into an analysis line fed to gas analysers. A flammability sensor was incorporated into the line as part of the rig safety system. The pressures were essentially ambient, with only the excess pressure required to maintain the flow rate through the system to the flue.

This air-biogas mixture was fed to a top cylindrical section containing an electrical heater, which simulated the effect of a heat recuperation system that would typically be installed within a microturbine system. The simple heater was controlled by a Eurotherm temperature controller, with programmable upper and lower limits, between which the heater switched on (termed the “control band”).

The pre-heated air-gas mixture then flowed through the lower unheated catalyst modules, within which were located upstream and downstream thermocouples, T_u and T_d. The emerging combustion products were fed to an exhaust collection system, which also had a gas sampling line fed to another gas species analyser.

The catalysis modules were a modified 3-way exhaust catalyst, based on a system previously developed for natural gas vehicle engines.

A photograph of the test rig in the test cell is shown in Figure 39.

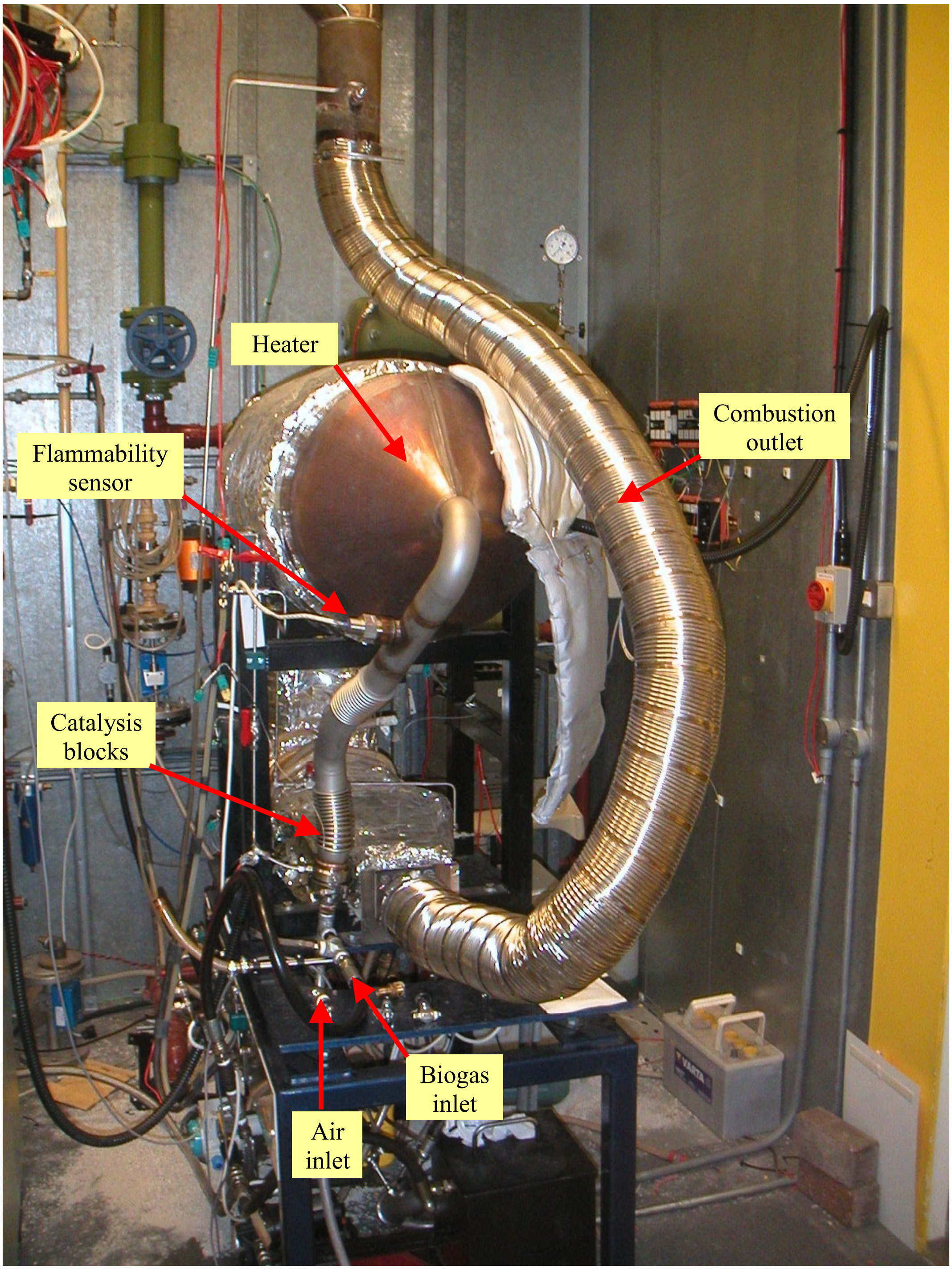


Figure 39: Photo of the Catalytic Combustion Test Rig in Advantica Test Cell 2

Catalytic Combustion Rig Tests

Tests CR1-3: 3rd October 2002

Three tests were carried out in succession to commission the catalytic combustion test rig, and to assess the range of pre-heat temperatures required to enable light-off within the catalyst modules, and how the temperature readout for the

Eurotherm heater controllers related to the gas temperatures arriving at the catalyst modules. The test series started with a relatively high pre-heat temperature (300°C), to maximise the light—off probability, declining through to 150 °C.

The heater control band was reduced through the test sequence from 60 °C to 20 °C. The air flow-rate was set[8] at a low value of 3.63 litres/s, the consistency of which was ensured by a regulator. The Land Lancom Series II portable gas analyser was set to monitor the CO_2 content of the fuel-air mixture composition to confirm the fuel-air ratio. The fuel delivery controls were adjusted so that CO_2 level in the fuel-gas mixture was 1.41 % (fuel-air ratio; 8.93).

<u>Results</u>

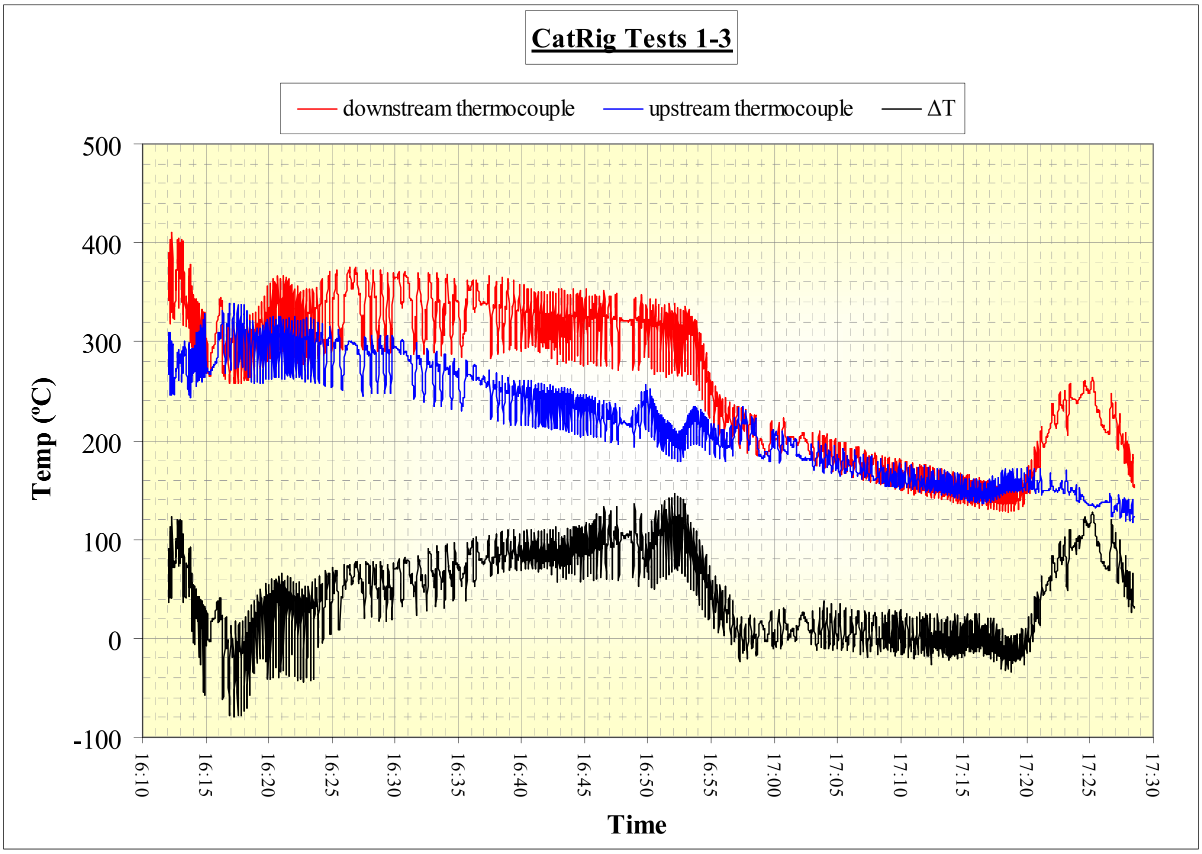


Figure 40: Temperature record of CatRig Tests 1-3

<u>Interpretation and Subsequent Modifications</u>

These tests confirmed that light-off of the fuel-air mixture was easily achieved and maintained throughout that temperature range, with a rise in temperature through the catalyst modules of approximately 100 °C.

The tests also highlighted the issue arising from the value of the set heater control band, leading to an inlet gas temperature swing. An important test measurement was the temperature increase between the upstream and downstream thermocouples, arising from fuel-gas mixture light-off. There was a significant time delay between the input gas temperature swings being detected by the

[8] The meter had a rotating dial with a mark on it as the lowest counting mechanism. 10 full rotations of this dial changed the main counter by 1, which was calibrated in 100's of cubic feet. Hence a single rotation corresponded to 10 cu ft, or 283.1685 litres. The gas delivery was measured to give 1 rotation over 78 seconds, yielding the quoted result.

thermocouples within the catalyst modules, leading to the temperature between the readings being significantly affected by such swings. This unwanted artefact was minimised by reducing the temperature-switching band of the Eurotherm controller to the practical minimum for subsequent tests; this was found to be 4 °C, below which the thermal inertia of the system was found to dominate.

At the set compressed air flow-rate used in these tests, the total calorific power delivered by the biogas flow-rate was much lower than a realistic system. It was felt that the thermal inertia of the catalyst modules could significantly distort the downstream thermocouple temperature measurements, especially if the light-off were occurring within only a small portion of the catalyst module leading surfaces.

Also it was found that the required biogas flow-rate was well above the range of the low flow-rate rotameter built into gas blending unit constructed for the Microturbine tests, but below the bottom of the range for the high flow-rate rotameter.

Accordingly, the compressed air flow-rate was set at a higher value to attempt to rectify these issues. The rate was increased to the maximum that the available regulated compressed air system could deliver[9], 11.64 litres/s.

The use of the Land Lancom Series II portable gas analyser to monitor the CO_2 content of the fuel-air mixture composition meant that the NOx in the combustion outlet was not available. Hence a Servomex 1400 CO_2 unit, capable of detecting 0-80% CO_2 was deployed to monitor the fuel-air mixture sample line for CO_2 content, and the Land unit reverted to combustion product sample analysis.

As the methane component would be the last of the three fuel species to remain unoxidised after traversal through the catalyst[10], a measurement of the amount of methane remaining in the combustion outlet would provide a very sensitive test for catalyst module effectiveness. To enable this measurement, the ADC methane analyser was deployed in the combustion sample line.

Test CR4: 7th October 2002

CatRig Test 4 was carried out after the above modifications had been carried out.

The steady flow of compressed air was pre-heated to approximately the desired temperature prior to increasing the smaller flow of biogas. The CO_2 content of the fuel-air mixture was monitored via the Land Lancom Series II portable gas analyser until the mixture was approximately correct. The flammability of the mixture output by the flammability meter was monitored during this process.

Results

The fuel delivery controls were adjusted so that CO_2 level in the fuel-gas mixture was 1.3 %, giving an air:fuel ratio of 9.77:1, indicating a biogas delivery rate of 1.19 litres/s.

A full set of gas species results, averaged over defined periods during the test is presented in Section 0. The level of methane in the combustion outlet stream was

[9] The gas delivery was measured to give 3 rotations in 73 seconds, yielding the quoted result.
[10] The Hydrogen component is easily oxidised by the catalyst, followed by the Carbon Monoxide.

found to be 0.061% v/v. The average increase in temperature between the catalyst thermocouples was 239 °C.

The time series logged data for the test is shown in Figure 41. The gas species concentrations have been normalised, so that the minimum concentration is at zero, the maximum at 1. The span for each is shown in the key. Note that the fuel CO_2 level was also logged, but the instrument output was affected by noise, and so has been omitted for clarity. The fuel CO_2 levels were taken as those read from the instrument panel, corrected as described in Sections 0 & 0.

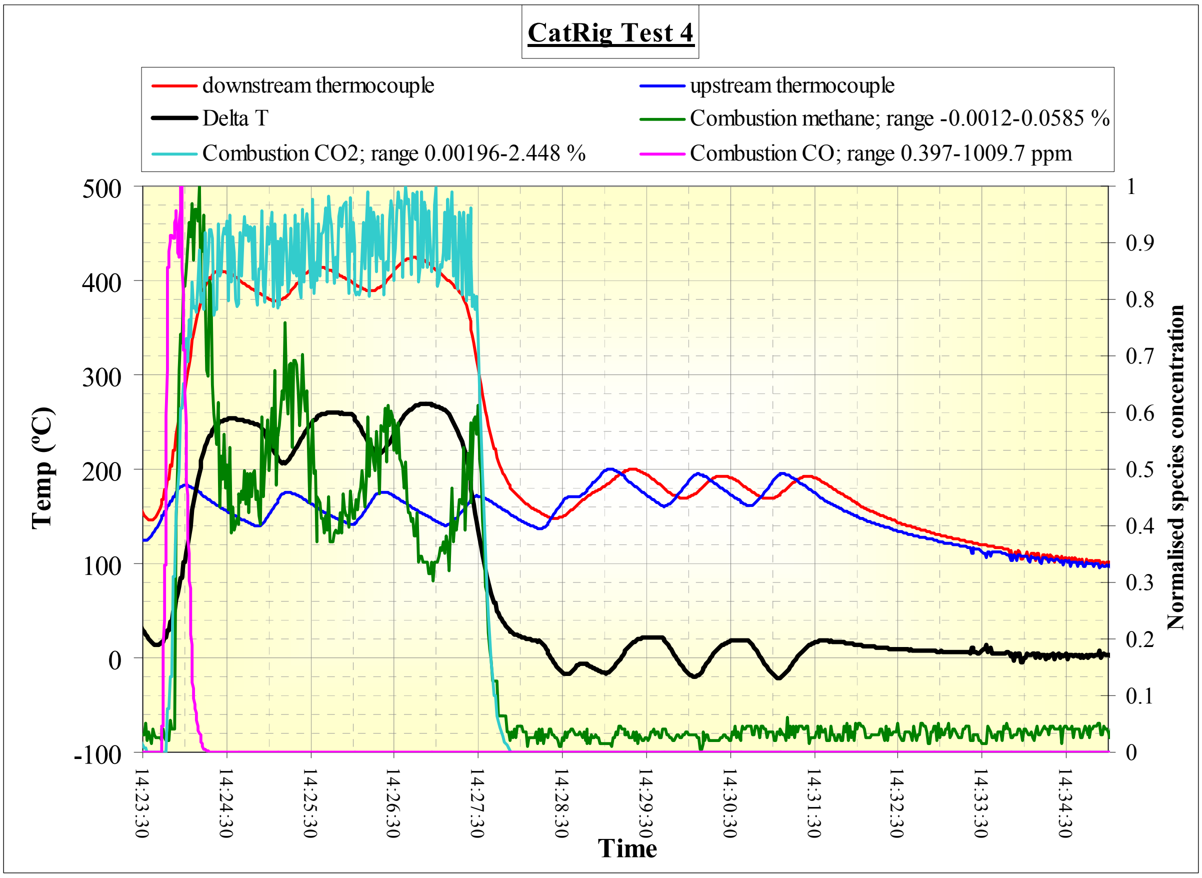


Figure 41: Temperatures and gas species concentrations for CatRig Test 4

Interpretation and Subsequent Modifications

It is interesting to note that the unoxidised methane fraction counter-correlates with the temperature increase between the upstream and downstream catalyst module thermocouples.

Whilst the average methane level in the combustion outlet of 0.061% v/v was not high in an absolute sense, when the dilution of the fuel in air was taken into account, and the relatively small fraction of methane in the biogas fuel source was allowed for, this measurement indicated that over 28% of the methane input to the catalyst module remained unoxidised. Hence it was decided to investigate how this fraction varied with pre-heat temperature.

Tests CR5-7: 7th October 2002

Tests CR5-7 were carried out in series to amplify the dependence of the unoxidised methane fraction downstream of the catalyst module on pre-heat temperature. The fuel-air mixture pre-heat temperatures were increased in steps of approximately 20 °C, with measured pre-heat temperatures of 179, 202 and 226 °C

Results

The results are shown in graphical form in Figure 42. A full set of gas species results, averaged over defined periods during the test is presented in Table 19 in Section 0. The levels of methane in the combustion outlet stream was found to be 0.042, 0.022 & 0.016 % v/v respectively, showing more effective methane oxidation at higher pre-heat temperatures.

The average increase in temperature between the catalyst thermocouples was 243, 251 and 241 °C respectively.

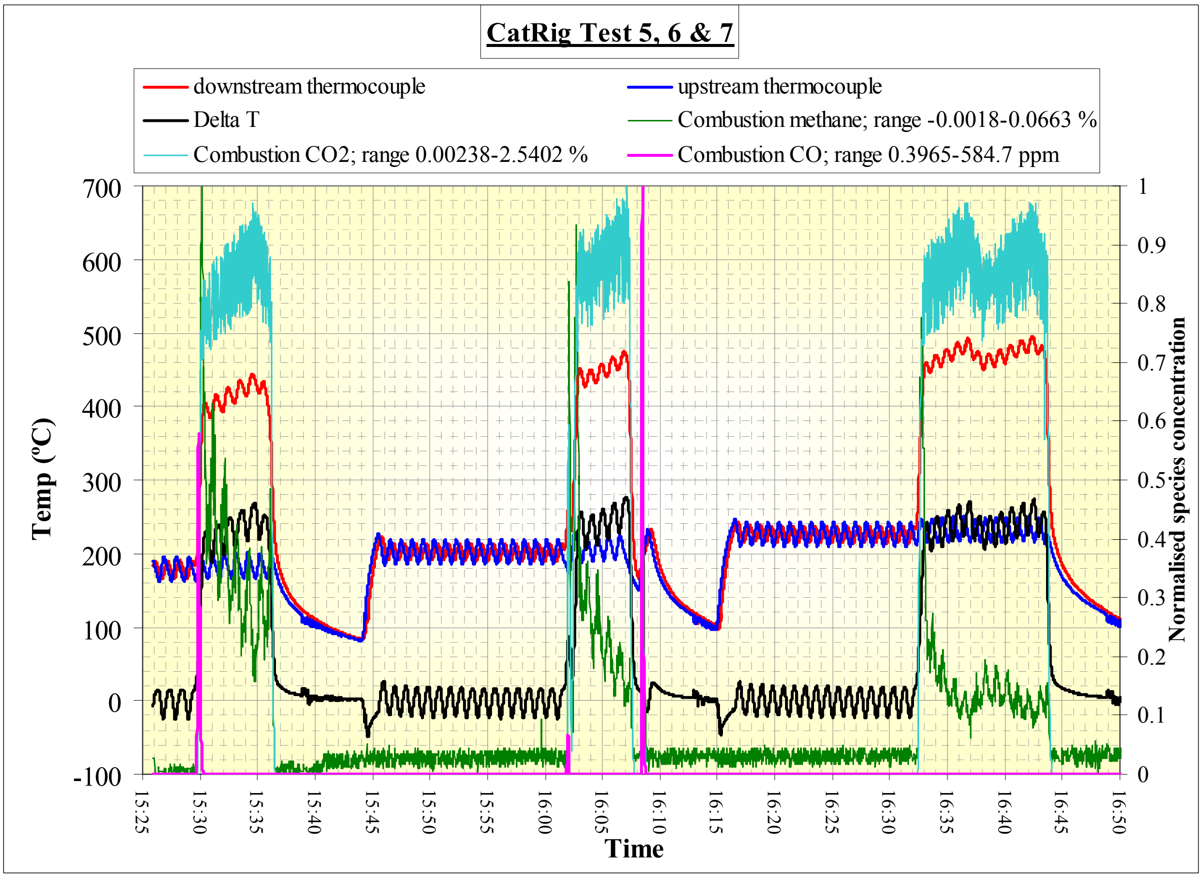


Figure 42: Temperatures and gas species concentrations for CatRig Tests 5-7

Interpretation and Subsequent Modifications

The results from Test 7 at a pre-heat of 226 °C indicated that 8% of the input methane fraction remained unoxidised, and an extrapolation of the results indicated that this would be significantly reduced at a pre-heat temperature of 250 °C.

Hence it was decided to perform one further test of the catalyst module performance at approximately this temperature, with the additional objective of acting as a demonstration test, tying in with that planned for the Microturbine.

Demonstration Test CR8: 9th October 2002

A test similar to Tests 5-7 was carried out, with a pre-heat temperature of 260 °C. The test was witnessed by Andrew Connor.

Results

The temperatures and gas species concentrations are shown in Figure 43.

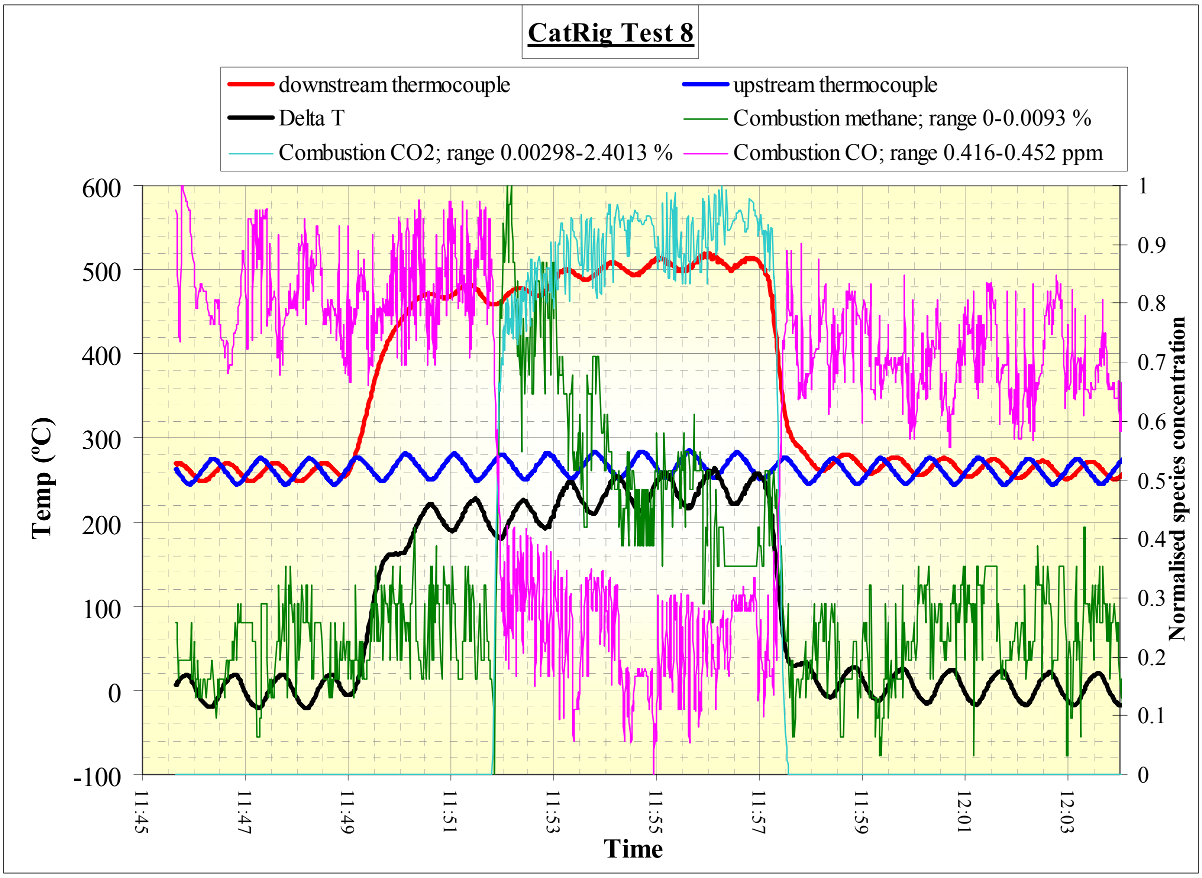


Figure 43: Temperatures and gas species concentrations for CatRig Test 8

Unlike previous tests, there was no point where significant CO from the biogas exited from the catalyst module. As a result, Figure 43 highlights the general result that the measured CO concentration in the combustion outlet stream was consistently lower than for the inlet stream, albeit at a very low levels for both. This difference is shown in the overall results Table 19 in Section 0, consistently being about 0.2 ppm lower than for the compressed air mixture. It should be noted that this result is derived from very small signal differences, and it is possible that it could be arising from an instrumental artefact. However, it is clear that all the CO present in the biogas has been oxidised after traversal through the catalyst modules.

The average level of methane in the combustion outlet stream at stable temperature was found to be 0.004 % v/v, this being the lowest methane result obtained. The average increase in temperature between the catalyst thermocouples was 219 °C.

The fraction of unoxidised methane input was 2.33%. The trend with pre-heat temperature is discussed in Section 0.

Calibration of gas sampling instrumentation

The various gas-sampling instruments were calibrated using the supplied synthetic biogas as a reference. Concentrations within this range were addressed by using mixtures of the biogas diluted in air. The instrument response ratios were examined to establish whether they were in the linear regime. This was carried out with three additional mixtures across the range. All the instruments were found to be responding linearly.

This process was not possible for the CO readings, where the biogas CO concentration significantly over-ranged the instruments used. The existing calibrations were taken in this instance.

Minimisation of instrument drift by analysis

Times were designated for each test when the fuel-air mixtures were being fed to the catalyst modules, and other period when no mixture was flowing as close as reasonable in time. This enabled a “zero” datum to be defined in each instance, minimising any effects of instrumental drift.

Results summary

The test results averaged over defined periods of “zero” baseline and “during test” periods are presented in Table 19.

Table 19: Summary of all average results for Catrig Tests 4-8 inclusive

Test	Parameter	Baseline		Steady signal		Thermocouple temperatures				Pre-catalyst		Post-catalyst				Flow rates		Methane fraction unburnt	Air:Fuel ratio	Biogas power delivery
		start time	end time	start time	end time	preheat	Catalyst up-stream (T_u)	Catalyst down-stream (T_d)	−T	CH_4 via fuel CO_2	CO_2	CH_4	CO_2	CO	NO_x	Fuel	Air			
	Unit	hh:mm:ss	hh:mm:ss	hh:mm:ss	hh:mm:ss	°C	°C	°C	°C	% v/v	% v/v	% v/v	% v/v	ppm	ppm	l/s	l/s	%	x : 1	kW
4		14:16:00	14:17:00	14:26:00	14:27:30	153	158	398	239	0.212	1.293	0.061	2.374	-0.019	2	1.184	11.64	28.53	9.83	5.25
5		15:26:00	15:29:30	15:34:00	15:36:00	179	183	426	243	0.203	1.238	0.042	2.399	-0.025	2	1.129	11.64	20.59	10.31	5.00
6		15:48:00	16:00:00	16:06:00	16:07:20	202	200	451	251	0.208	1.264	0.022	2.502	-0.022	2	1.155	11.64	10.53	10.07	5.12
7		16:18:00	16:30:00	16:35:00	16:43:00	226	233	474	241	0.194	1.183	0.016	2.408	-0.023	2	1.074	11.64	7.98	10.84	4.76
8		11:59:00	12:04:00	11:55:00	11:57:00	260	265	485	219	0.171	1.042	0.004	2.400	-0.017	2	0.936	11.64	2.33	12.43	4.51
100% Fuel mixture										2.3	14	--							0	--
Ideal microturbine Fuel mixture										0.193	1.177	--							10.898	--

CatRig Test interpretation and conclusions

Variation of methane in outlet with pre-heat temperature

The trend of unoxidised input methane fraction with biogas-air mixture pre-heat temperature is shown in Figure 44. Linear and exponential projections of trend are indicated. The air:fuel ratios and net CV biogas power deliveries are also shown for information.

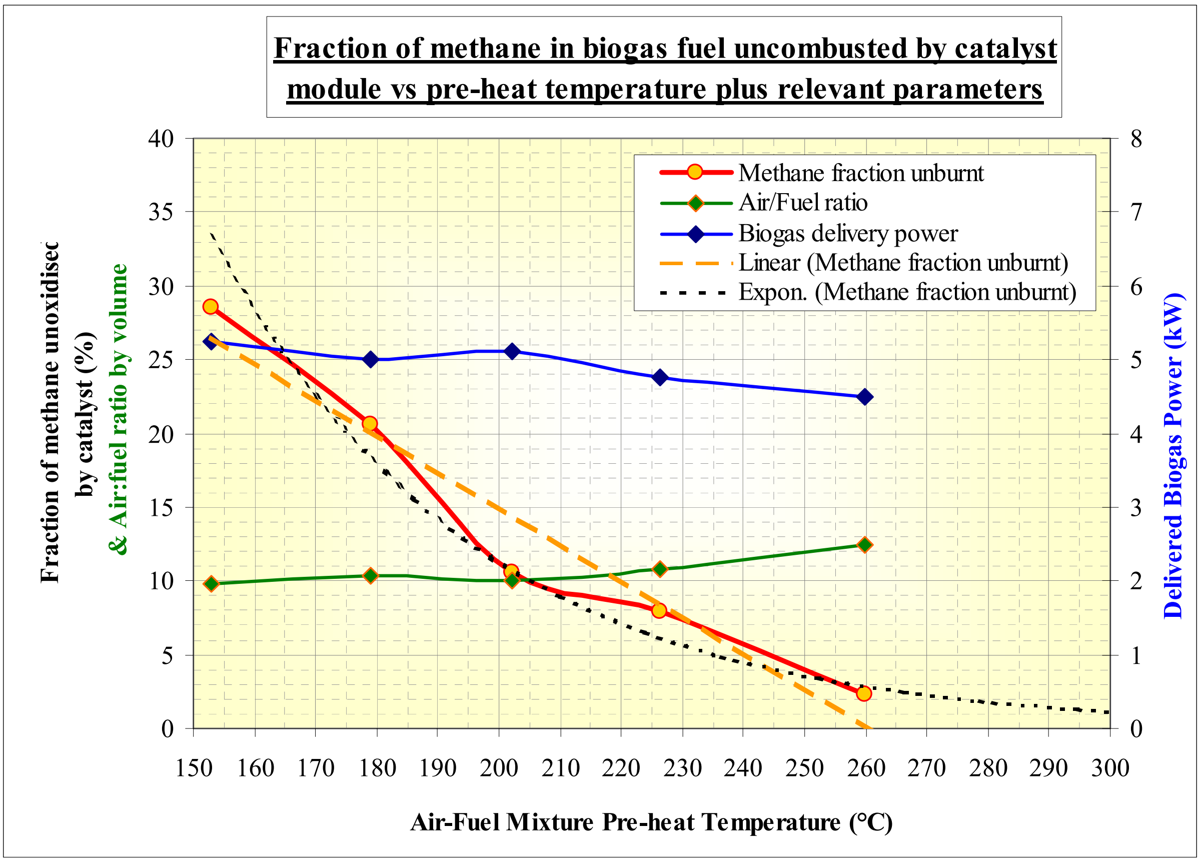


Figure 44: Dependence of unburned methane fraction on pre-heat temperature

The catalyst modules have proven to be highly effective at oxidation of the biogas fuel components within realistic biogas-air mixtures over a range pre-heat temperatures. The most resistant fraction to oxidation, the methane component, was 90% oxidised at pre-heat temperatures above approximately 200 °C. This temperature is easily attainable in microturbine systems via heat exchangers transferring heat from combustion outlet stream to the input air-fuel stream.

This gives an additional mechanism to utilise biogas as a microturbine fuel should the direct fuelling of the microturbine combustion chamber prove untenable.

The CO oxidation is extremely effective, with combustion outlet CO levels at least as low as those present in ambient air.

The catalyst module was capable of oxidising the highest flow-rate of biogas used in the tests (5.25 kW). Further tests would be required to determine an upper limit to this performance.