Technical Support of the U.S. DOE Biomass Power Program in the Development of Biomass to Electricity Technologies.

Richard L. Bain and Ralph P. Overend
National Renewable Energy Laboratory
Industrial Technologies Division
1617 Cole Boulevard
Golden, CO 80401-3393

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INTRODUCTION

In the USA the period since 1973 to the present, has resulted in a dramatic upswing in bioenergy use and applications uses especially in thermal and electrical applications of mainly wood residues. The wood processing and pulp and paper sectors became about 70% self sufficient in energy in that period and the amount of grid connected electrical capacity increased from less than 200 MW in 1978 to over 7,500 MW_e today. This dramatic growth stimulated in part by federal tax policy and state utility regulatory actions, occurred after the Public Utilities Regulatory Policies Act (PURPA) of 1978 guaranteed small electricity producers that utilities would purchase electricity at a price equal to the utilities' avoided cost.

More than 70 percent of biomass power is cogenerated with process heat. Wood-fired systems account for 88 percent, agricultural waste (3%), landfill gas (8%), and anaerobic digesters (1%). There are nearly 1000 wood-fired plants in the U.S., typically ranging from 10 to 25 MW_e. Only a third of these plants offer electricity for sale. The rest are owned and operated by the paper and wood products industries for their own use. Most of today's biomass grid connected power installations are the smaller scale independent power and cogeneration systems. To date, utilities have been involved in only a handful of dedicated wood-fired plants in the 40 to 50 MW_e size range, and in some co-firing of wood and municipal solid waste in conventional coal-fired plants.

Net plant heat rates for 25 MW_e plants in the California PG&E service territory average approximately 18 percent efficiency (17,000 Btu/kWh). By comparison the 43 MW_e utility-operated plant at Kettle Falls, Washington has a reported heat rate of 26% efficiency (14,382 Btu/kWh). However, the advantageous power purchase agreements that were negotiated under PURPA in the 1980s are no longer available at high rates of avoided costs. As a result a number of plants are closing as their power contracts come up for renewal. They could be competitive in today's environment using low cost waste and residue fuels if their efficiency was much higher as has been demonstrated in the sugar industry of Hawaii where the power plants operate for a major part of the year as CHP installations. Investments in efficient steam cycles has resulted in a competitive rate of power generation under PURPA. Low pressure boilers were systematically replaced by higher pressure boiler systems of larger capacity in the period 1960 through 1980 with the average steam pressure and temperature increasing from 1.3 MPa and 210 °C to 4.4 MPa and 380 °C. Meanwhile the net steam consumption in the mills decreased significantly from 600 kg /tc to about 300-400 kg/tc; resulting in a power output of about 60 kWh/tc on average with the best mills reaching over 100 kWh/tc.

Biomass Power Efficiency Advances are Needed in order to be competitive with low cost fossil fuels, especially in stand alone power generation, will require a considerable Increase in the power to heat ratio and will require advanced technologies - such as the use of IGCC (Integrated Gasification Combined Cycles) as illustrated in Table 1.

As can be seen, the increase in efficiency has two effects: it reduces the capital cost on a kW basis, and it reduces the sensitivity of the final cost of electricity to the fuel cost component.

The USDOE Biomass Power Program is working to address the issues of making biomass competitive by working with today's industry to increase its reliability and to develop advanced systems for increased efficiency and environmental performance.

The pathways under discussion are included in Figure 1.

Support for today's Industry: In general the biomass power industry has displayed good reliability, however, in the case of the IPP Biomass fueled stations in California, operational difficulties rapidly emerged when using non-wood biomass fuels[1]. The operational difficulties were caused by the deposition of mineral matter on the heat exchange surfaces (boiler tubes, superheaters, and water walls) and by the agglomeration of ash and inert fluid bed materials. This problem is one that is costly as it results in down-time for tube cleaning and repair, and because there is considerable interest in the development of dedicated crops such as short rotation woody crops and herbaceous energy crops for bioenergy applications it could be a problem that would affect the long term large scale deployment of biomass fuels in both electricity generation and the production of liquid fuels. For this reason the USDOE through NREL initiated a collaborative study with industry on the ash deposition problem[2] with the goal of establishing the root cause of the difficulties in using non-traditional biomass fuels.

While the nature of the direct combustion boiler problem is of current concern, NREL also recognized that these same issues may have to be addressed in the non-combustion processes such as fast pyrolysis, and gasification that convert biomass into intermediate fuels that would be used in very high efficiency generation systems based on gas turbines. Gas turbines are extremely sensitive to both mineral matter and to alkali metals. For the state-of-the-art turbines with turbine inlet temperatures of 1260°C (2300 °F) the manufacturer's specifications call for less than 300 ppb of alkali metal in the hot section. Since high efficiency biomass to electric conversion is a goal of the USDOE Biomass Power Program[3] a program of testing non-woody and short rotation biomass feedstocks in gasifiers and fast pyrolysis processes was instituted.

The Ash Deposition Problem was addressed by conducting extensive fuels and deposits analysis and through an extensive collaboration the cause was identified. The project received over 700 different fuels analyses from the participants, however, the majority of these did not have the critical ash analysis data. However, this may not have been such a bad omission since the project has established that there are major problems with the standard ash determination methods that are accepted as standards for coal materials. The ASTM methods for coal prepare an ash at 800 °C which is then used for the pyrometric cone analysis to determine if there will be a slagging or sticky problem. Unfortunately the critical element causing the ash deposition and fouling problem is potassium and it is known that this and other mineral matter from biomass will evaporate from the ash at 800 °C, decreasing its mass and altering its fusion properties[4]. Potassium is a key component of cellular function and in plants it can be present at 1000 times the concentration of sodium. As much as 35% of the ash in annual plants can be alkali which drastically reduces the ash fusion temperature from greater than 1300 °C in the case of wood ash to about 700 °C where the potassium can form a eutectic with the plant's silica or the sand medium of the fluidized bed[5]. Work with the MBMS system at NREL has shown that the form in which potassium is transported can be very diverse including oxides, hydroxide, sulphite/ate, and chlorides as volatiles[6].

Gasification Developments: Commercial biomass gasifiers are already in use to generate process heat and steam. Current development activities are focused on producing electricity and, to some extent, liquid fuels, and involve integrating gasification with various cleanup systems to ensure a high-quality and reliable gas product. At this time, there is no clear preference for a single gasifier system. The Global Environment Facility[7], is evaluating two systems offered by Scandinavian commercial developers for the CHESF project in NE Brasil. The evaluation will compare the advantages and disadvantages of using air gasification at high pressure (Bioflo) or at low pressure (the TPS system). High-pressure gasification would have to meet the pressure requirements of the chosen turbine on all system components, including the gas clean-up system; the low-pressure system would carry out the gas cleaning before compressing the fuel gas to the turbine operating pressure. Air blown systems only produce a low-heating value gas (less than 150 Btu/ft^3, 5-6 MJ/Nm^3), and a significant loss in efficiency is imposed if the gas must be cooled to ambient temperatures prior to being compressed. For this reason, the American and Scandinavian gasification programs are emphasizing using hot gas clean-up systems for the air-blown, low heating value gasifiers that will be operated at pressure.

The U.S. program has a dual-pathway strategy involving both low and medium heating value gas production. One high pressure system is capable of generating either low or medium heating value gases according to whether it is an air- or oxygen-blown variant, and is the Renugas® system developed by IGT. The low-pressure strategy in the U.S. is based around two developers of medium heating value gas systems who do not use oxygen, rather use indirect gasification to produce gases having heating values of 350-450 Btu/ft^3(15 - 20 MJ/Nm^3). Cooling and quenching the gas does not incur a significant efficiency penalty and, compared with low-heating value gas, there are essentially no modifications required in the turbine combustors to handle the medium-heating value gas fuels.

The Pacific International Center for High Technology Research (PICHTR) Project (>6 MW): The U.S. Department of Energy (DOE) and the state of Hawaii have joined with PICHTR in a cost-shared cooperative project to scale up the Institute of Gas Technology (IGT) Renugas® pressurized air/oxygen gasifier to a 45-90 ton/day engineering development unit (EDU) operating at 1-2 MPa using bagasse and wood as feed. The site is the HC&S sugar mill at Paia, Maui, Hawaii, and NREL is providing project oversight in addition to systems analysis. The first phase, which is now being commissioned consists of the design, construction, and preliminary operation of the gasifier to generate hot, unprocessed gas. The gasifier is designed to operate with either air or oxygen at pressures up to 2.2 MPa, at typical operating temperatures of 850°-900°C. In Phase 1, the gasifier will be operated for about four months at a feed rate of 45 ton/day at a maximum pressure of 1 MPa. Following the end of Phase 1 in late 1995, a hot-gas cleanup unit and gas turbine will be added to the system to generate 3–5 MW of electricity.

The Vermont Gasifier Project with FERCO and the McNiel Generating Station (>15MW) Future Energy Resources Company (FERCO) of Atlanta, GA, is the licensee of the Battelle indirect gasification system, and the scaleup is at the site of the Burlington Electric Department's McNeil station in Burlington, VT. The project, which is in two phases, will first take feedstock from the 50 MWe station and after gasification will return the gas to the boiler. The scale of operation is about 200 tpd. The second phase will incorporate approximately 15 MW_e of turbine electricity generation. The project is jointly funded by USDOE and FERCO and presently construction forecast to start in Fall 1995.

National Renewable Energy Laboratory (NREL) Activities: The research strategy is guided by systems analysis and technoeconomic assessments of gasifier-based power cycles. In the laboratory, research is ongoing to develop catalysts for hot gas conditioning, and use of advanced instrumentation and chemometrics for feedstock characterization and evaluation. One element of this research is using advanced mass spectrometry to characterize alkali metal speciation under gasification and combustion of biomass conditions. This work has been extended to develop and using a transportable molecular beam mass spectrometer (TMBMS) for real time measurement of hot stream composition to 500 atomic mass units (amu). The TMBMS is being used by both Battelle and IGT to measure gasifier and catalyst performance in the field.

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Table 1. Comparison of present day steam generation with IGCC

Cost factors (¢/kWh)	Steam Generation	IGCC
Operations and Maintenance	0.5	0.5
Fuel only Cost	3.6	1.6
Capital Recovery	4.2	3.0 -3.5
Cost of Electricity	8.3	5.1-5.6

Notes to Table 1. Assuming a marginal cost of fuel of $2/million Btu (or approximately $40/tonne of dry biomass), a load factor of 85% (base loaded), and a return on capital invested of 8%/year, it is possible to see the effect of the new technology. Both plants are approximately 50 MW_e capacity. The efficiency of the steam plant is about 20%, while the IGCC is estimated to have an efficiency of 45%. The capital cost of the steam plant is $1.8/W, while that of the IGCC is expected to be in the range of $1.3 to $1.5/W.

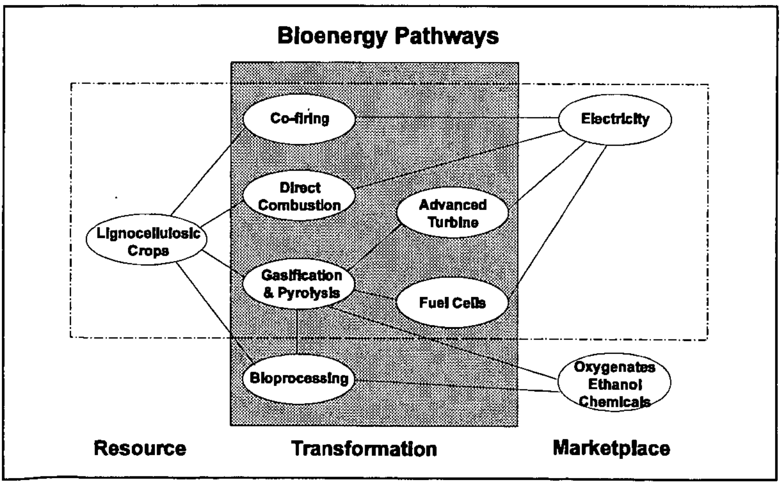

FIGURE 1: Bioenergy pathways.