Advanced Biopower Technology Assessment

Prepared for the:

Massachusetts Division of Energy Resources

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Massachusetts Department of Conservation & Recreation

Massachusetts Sustainable Forest Bioenergy Initiative

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1.0 Introduction

Massachusetts Technology Collaborative (MTC) has retained Black & Veatch to assist in reviewing the current commercially available technologies for biomass power conversion and for controlling emissions, and provide a report on the status of the marketplace, the technology advancements in the past 10-years, and potential for further advancements in each area. The work was divided into the following two tasks:

- Task 1 – Review of advanced biomass conversion technologies
- Task 2 – Review of conventional technologies with advanced design features

This report summarizes the findings of Task 1 and Task 2.

1.1 Background

The Massachusetts Division of Energy Resources (DOER) issued the Renewable Portfolio Standard (RPS) to diversify the state's electricity supply portfolio, stabilize rates, increase energy security, improve environmental quality, and invigorate the clean energy industry. The RPS (see 225 CMR 14.00 *Renewable Energy Portfolio Standard*) became effective on April 26, 2002. In order to determine whether a renewable energy facility qualifies as a New Renewable Generation Unit (NRGU) under the RPS regulations, the DOER utilizes the following energy source, fuels and technology criteria as identified in 225 CMR 14.05(1):

- Solar photovoltaic or solar thermal electric energy
- Wind energy
- Ocean thermal, wave, or tidal energy
- Landfill methane gas and anaerobic digester gas, provided that the fuel is directly supplied to the generating unit rather than conveyed through conventional delivery networks for natural gas
- Low-emissions, advanced biomass power conversion technologies using an eligible biomass fuel
- Fuel cells using an "eligible biomass fuel," landfill or anaerobic digester methane gas, hydrogen derived from such fuels, or hydrogen derived using the electrical output of a qualified renewable generation unit. (Fuel cells using hydrogen derived from other fuels or from electricity produced by non-renewable units are ineligible).

One of the criteria identified above is the fuel and technology criterion (225 CMR 14.05(1)(a)6, which requires a NRGU to use "Low-emissions, advanced biomass power conversion technologies using an eligible biomass fuel…" In November 2006 the DOER issued the first proposed revisions to the RPS regulations and a concurrent Guideline to clarify how DOER intends to evaluate Statement of Qualification Applications for biomass-fueled NRGUs to meet the "low emission" and "advanced biomass conversion technology" criteria under the RPS.

The Guideline establishes a preliminary set of emission limits for nitrogen oxides (NO_x) and particulate matter (PM) for wood-fired and other solid-fuel fired steam boilers to meet the "low-emission" criterion. The Guideline also clarified that compliance with these limits would be in addition to any other potentially more stringent emission limits imposed by the biomass unit's air construction permit issued by the Massachusetts Department of Environmental Protection (DEP). Table 1-1 presents these "low-emission" limits and associated monitoring and testing requirements. The Guideline also clarifies that DEP will be consulted in setting emission limits for a NRGU that does not utilize a steam boiler fueled by wood or other approved solid fuel.

Table 1-1. RPS Monthly Average Emission Limits for Wood-Fired and Other Solid-Fueled Steam Boilers.

Name Plate Capacity	NO_x lb/MBtu	PM lb/MBtu	Monitoring/Testing
< 1 MW	0.30	0.012	Portable monitor for NO_x, O_2, and CO. Initial stack test for PM, NO_x, and CO, and retest every five years
1-10 MW	0.15	0.012	Portable monitor for NO_x, O_2, and CO. Initial stack test for PM, NO_x, and CO, and retest every three years
>10 MW	0.065	0.012	Continuous Emissions Monitoring System (CEMS) for NO_x & CO. Annual stack test for PM. CO CEMS as surrogate for PM monthly average
Source: Table One, Guideline on the RPS Eligibility of Biomass Generation Units			

The proposed new regulations also clarify that a biomass power conversion technology is "advanced" if it meets one of the following criteria:

- It has become commercially available not more than 10 years prior to the date of the unit's Statement of Qualification application (SQA) submission to DOER, or
- The class of power conversion technology (e.g., stoker, fluidized bed) has been commercially available for more than 10 years but has design features

that have become commercially available within 10 years prior to the date of the unit's SQA submission that will improve the unit's performance in at least one of the following areas: fuel conversion efficiency, operations and maintenance, or materials.

This report reviews the technologies that have become available in the past 10 years and older or conventional technologies that utilize advanced design features.

1.2 Report Organization

Following this Introduction, this report is organized into the following sections:

- **Section 2 – Advanced Biomass Conversion Technologies:** The section presents an assessment of biomass power conversion technologies that are not conventional and have become commercially available in the past 10-years or are in the process of becoming commercially available. These technologies are increasingly being considered for power generation and could potentially qualify as "advanced biomass power conversion technology" under the RPS. In evaluating suitable technologies, key criteria included technical feasibility of the processes and the technology's developmental and commercial status.
- **Section 3 – Conventional Technologies with Advanced Designs:** The section presents an assessment of conventional biomass power conversion technologies that when coupled with advanced designs could potentially result in improved unit performance.

2.0 Advanced Biomass Conversion Technologies

The section presents an assessment of biomass power conversion technologies that are not conventional and have become commercially available in the past 10-years or are in the process of becoming commercially available. These technologies are increasingly being considered for power generation and could potentially qualify as "advanced biomass power conversion technology" under the RPS.

There are a huge variety of biomass resources, conversion technologies, and end products. Extracting energy from biomass employs a wide range of processes including anaerobic digestion, combustion, fermentation, gasification, pyrolysis, and physiochemical processes. The mix of technologies is constantly evolving to meet the demand for a huge array of alternative bioproducts, including power, fuels, specialty chemicals, and other products. For power generation from biomass fuels, direct combustion has long been the preferred technology. Almost all of the nearly 10,000 MW of biomass and waste fired power plants in the U.S. rely on direct combustion technology. Biomass gasification is an emerging alternative that can be used in advanced power cycles such as integrated gasification combined cycle (IGCC). Further, by converting solid fuel to a combustible gas, gasification expands the end use options for biomass. Gasification allows the use of cleaner and more efficient power conversion processes such as gas turbines and fuel cells to produce power, and/or chemical synthesis to produce ethanol and other value added products. Pyrolysis offers similar promise to gasification. Pyrolysis processes are in the early stages of commercialization and focus on production of value added chemicals rather than steam or power.

The remainder of this section reviews gasification and pyrolysis as the advanced biomass conversion technology options. Conventional direct combustion technologies are considered in Section 3.0.

2.1 Gasification Technologies

Biomass gasification is a thermal process to convert solid biomass into a gaseous fuel (syngas, also known as producer gas). This is accomplished by heating the biomass to high temperatures in an oxygen-deficient ("fuel rich") environment. Gasification is a promising process for biomass conversion. By converting solid fuel to a combustible gas, gasification offers the potential of using more advanced, efficient and environmentally benign energy conversion processes such as gas turbines and fuel cells to produce power. It is also possible to process the syngas to produce hydrogen, ammonia, naphtha, cresylic acid, phenol, ethanol and other value added products.

Provided it is clean enough, the syngas created from gasification could also be used to displace natural gas currently used in gas-fired boilers, dryers, and other applications.

This section provides a brief history of biomass gasification, followed by a description of gasification fundamentals and a discussion of gas quality issues. The section also describes the various gasifier technology options, including gas conversion options and biomass integrated gasification combined cycle.

2.1.1 Gasification History

The history of gasification has been sporadic. Near the beginning of the twentieth century, over 12,000 large gasifiers were installed in North America in a period of just 30 years. These large systems provided gas to light city streets and heat various processes. Moreover, by the end of World War II, over one million small gasifiers had been used worldwide to produce fuel gas for automobiles. However, at the end of the war, the need for this emergency fuel disappeared; automobiles were reconverted to gasoline, and the arrival of large interstate natural gas pipelines put many municipal "gasworks" out of business. With the loss of equipment went the majority of the gasification artists – those who operated their generators with practical experience and intuition. In some cases, scientists and developers still struggle to reproduce with "state-of-the-art" technology what was routine operation half a century ago.

2.1.2 Gasification Fundamentals

Gasification is typically thought of as incomplete combustion of a fuel to produce a syngas with a low to medium heating value. Heat from partial combustion of the fuel is also generated, although this is not considered the primary useable product. Gasification lies between the extremes of combustion and pyrolysis (no oxygen) and occurs as the amount of oxygen supplied to the burning biomass is decreased. Biomass gasification can be described by the simple equation:

Biomass + limited oxygen → syngas + heat

Gasification occurs as the amount of oxygen, expressed in the equivalence ratio, is decreased. The equivalence ratio is defined as the ratio of the actual air-fuel ratio to the stoichiometric air-fuel ratio. Thus at an equivalence ratio of one, complete combustion theoretically occurs; at an equivalence ratio of zero, no oxygen is present and fuel pyrolysis occurs. Gasification occurs between the two extremes and is a combination of combustion and pyrolysis.

A formal definition of gasification might be the process that stores the maximum chemical energy in the gaseous portion of the products. Depending on the fuel and the reactor, the equivalence ratio for this condition can range between 0.25 and 0.35. An equivalence ratio of 0.25 represents the oxidation of one-fourth of the fuel. In most gasifiers, the heat released by burning this portion of the fuel pyrolyzes the remainder and produces a low heating value syngas. Below an equivalence ratio of 0.25, char (mostly solid carbon) begins to be substantially produced, and the gas production begins to taper off.

2.1.3 Gas Quality

The primary product of gasification is a low heating value syngas, alternatively known as syngas or producer gas. For air-blown gasification, the heating value of the syngas is typically 15 to 20 percent (150-200 Btu/ft^3) of the heating value of natural gas (1,000 Btu/ft^3); the heating value of the syngas is significantly reduced by the dilution of nitrogen from the process air. The combustion of air-blown syngas is illustrated in Figure 2-1. For oxygen- or steam-blown gasification, the syngas is not diluted by the presence of nitrogen, and the heating value of the syngas is typically 300-400 Btu/ft^3.

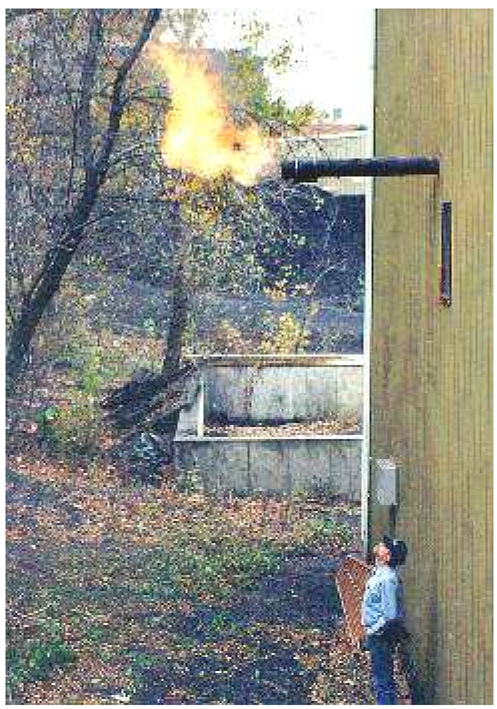

Figure 2-1. Gas Flare from an Experimental 5 TPD Biomass Gasifier.

Combustible components of the gas include carbon monoxide, hydrogen, methane, and small amounts of higher hydrocarbons such as ethane and propane. The syngas may also contain varying amounts of carbon dioxide and water vapor. The exact composition of the syngas depends on the operating temperature and pressure as well as the composition of the biomass feedstock. In general, higher pressures tend to produce more methane and water vapor and improve the carbon conversion efficiency of the gasifier. Higher temperatures tend to produce more CO and hydrogen.

The raw syngas exiting the gasifier also contains varying amounts pollutants and contaminants including sulfur and nitrogen compounds (hydrogen sulfide [H_2S], carbonyl sulfide [COS], ammonia, and hydrogen cyanide [HCN]); vapor-phase alkali and condensable hydrocarbons (tars); and particulate matter such as entrained ash. The syngas must be cleaned of these components before being burned to produce power or before further chemical processing. The removal of pollutants and contaminants is commonly referred to as gas cleanup, which is discussed below in the section titled, "Syngas Cleanup Issues."

2.1.4 Gasifier Technology Options

There is a huge variety of gasification technologies including updraft, downdraft, fixed grate, entrained flow, fluidized bed, and molten metal baths. Unlike combustion technologies discussed previously, it is difficult to generally group and categorize gasification technologies because of the wide variety of process variables that differentiate designs. These include:

- **Reactor type –** Many of the same technologies that have been developed for combustion can be adapted for gasification. These include grate systems and bubbling and circulating fluidized beds. Some of these technologies can alternately operate between combustion and gasification modes simply by varying the balance and distribution of air and fuel in the reactor. Named for the direction of gas flow in the reactor, small updraft and downdraft gasifiers are more traditional designs and have been widely studied and used. Because they minimize tar production, downdraft gasifiers have been employed in small engine systems. Updraft gasifiers (such as the Primenergy gasifier) are more tolerant of high moisture fuels, but produce much more tar than downdraft gasifiers. For this reason, updraft gasifiers are usually operated close-coupled to burners. In addition to these types, there are a large number of other potential gasifier reactor designs including entrained flow (common for coal gasification) and molten metal baths.
- **Oxygen, steam, or air-blown –** Air blown gasification produces a syngas with a low heating value, typically 15 to 20 percent (150-200 Btu/ft^3) of the heating value of natural gas. The heating value of the gas may be increased by using oxygen or steam to gasify the fuel. Either option removes most of the inert nitrogen from the syngas, raising the gas heating value to near 500

Btu/ft^3. High heating value gas can be more readily used in combustion turbines and for chemical synthesis. Large coal gasification plants typically use pure oxygen as the oxidant and are able to achieve substantially increased gas heating values. However, the cost of building a separate oxygen plant is not justified for biomass facilities, which are typically less than 50 MW.

- **Heating method –** Air-blown gasification partially combusts biomass to provide the heat necessary to drive the gasification reactions. Instead of directly burning part of the fuel, indirect heating can be used to increase the gas heating value. Many methods have been devised to supply this energy. Some experimenters have simply heated the reactors externally with natural gas or electrical resistance heaters. These approaches have only been done on the research scale because they are not very efficient at supplying heat to the reactor. More novel approaches for providing the heat include gasification in a molten metal bath, combustion of a portion of the syngas in immersed fire-tubes Manufacturing & Technology Conversion International, Inc. (MTCI), and dual circulating fluidized beds which circulate solids to transfer heat (FERCO).
- **Pressure –** Gasification systems can either be near atmospheric pressure or pressurized. Pressurized systems are preferred for applications that require the syngas be compressed (such as Fischer-Tropsch synthesis or gas turbines). However, pressurization complicates material feed and other aspects of the design.
- **Syngas conversion options –** There are many potential options for converting syngas to useful energy, as described further in the next section.

2.1.5 Gasification Syngas Conversion Options

The primary advantage of gasification over combustion is the versatility of the gasification product. Gasification expands the use of solid fuel to include practically all the uses of natural gas and petroleum. Beyond higher efficiency power generation available through advanced processes, the gaseous product (specifically CO and H_2) can be used for chemical synthesis of methanol, ammonia, ethanol, and other chemicals. Gasification is also better suited than combustion for providing precise process heat control (e.g., for drying or glass-making).

The various syngas conversion options are illustrated in Figure 2-2. These options include:

- **Close-Coupled Boilers –** Syngas from gasifiers has been traditionally fired in close-coupled boilers for power generation via a standard steam power cycle, as shown in Figure 2-3. Syngas is combusted in a traditional oil or natural gas boiler to generate steam. The steam then drives a turbine to produce power. This setup provides the most conventional method of generating power but also one of the least efficient, with efficiencies comparable to direct combustion processes (20 to 25 percent). A potential advantage of this approach compared to direct combustion is that separate gasification allows one to remove ash material prior to the combustion stage. This can benefit downstream gas combustion devices by reducing particulate loading, emissions, and boiler corrosion and slagging caused by alkali material in the biomass. The syngas can also be cofired in existing fossil fuel boilers with little modification required to the boiler (see figure). This is a potentially attractive option for fossil fuel plant owners looking to add renewable fuel to their portfolio, without having to build a new greenfield plant. It is also attractive for industrial boilers looking to re-power with biomass due to rising gas or coal costs. Compared to a greenfield biomass plant, the costs for a cofiring retrofit are much smaller.

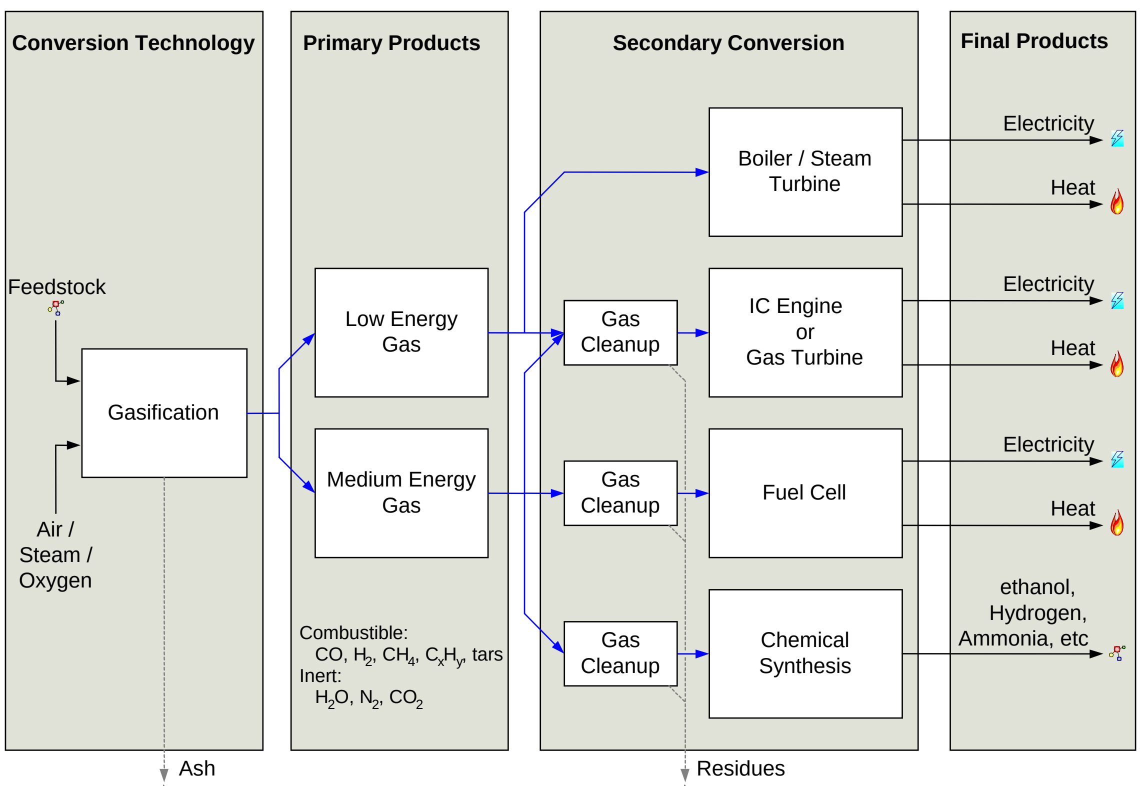

Figure 2-2. General Gasification Process Flow Options.

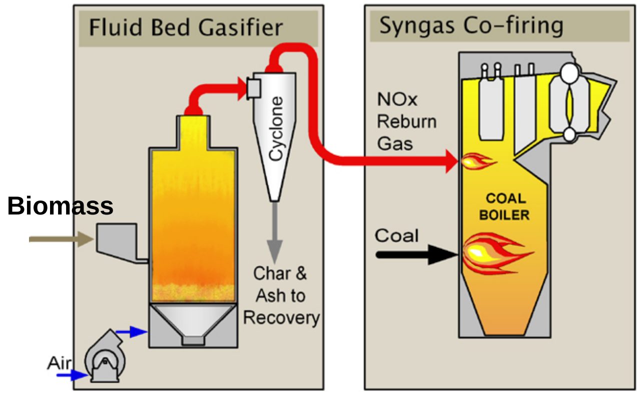

Figure 2-3. Gasification for Biomass Cofiring with Fossil Fuels.

- **Internal Combustion Engines and Combustion Turbines** – Gasifier syngas can also be fired in a reciprocating internal combustion (IC) engine or gas turbine. Use of syngas in IC engines has been demonstrated, particularly for smaller system sizes. Derivatives of jet engine technology, combustion turbines are more suited for larger sizes and are the centerpiece of integrated gasification combined cycle (IGCC) power plants, although these turbines must be designed or modified to fire the syngas. See further discussion below regarding issues with firing biomass-derived fuel in combustion turbines and biomass IGCC concepts.
- **Fuel Cells** – Fuel cells electrochemically convert syngas and air into power. In general, fuel cells are not expected to be commercially available for a few years. Gasification is best suited for higher temperature fuel cells designs such as molten carbonate and solid oxide. Because fuel cells extract energy directly from syngas, they are very efficient throughout their size range. Integrated gasification fuel cell (IGFC) plants are not a commercial reality at this point because of high capital costs and developmental issues related to the extensive syngas conditioning and clean-up that is required.
- **Chemical Synthesis (including ethanol)** – The components of syngas, particularly carbon monoxide and hydrogen, can be used as “building blocks” for a large variety of chemicals, fuels, fertilizers, and other products. One of the more promising pathways is production of ultra-clean liquid fuels (such as methanol, ethanol, and diesel) through Fischer-Tropsch synthesis. Chemical synthesis using biomass gasification typically requires clean syngas and is largely in the demonstration phase. Gasification is heavily promoted as one of the key building blocks in the Department of Energy’s “thermochemical

platform" for the production of high value products, like ethanol, from biomass. Although ethanol synthesis via gasification is not yet a proven technology, gasification projects could be phased to demonstrate the technology incrementally (natural gas displacement followed by ethanol synthesis). Such an approach is being explored by Chippewa Valley Ethanol, near Benson, Minnesota.

2.1.6 Syngas Cleanup Issues

All biomass-derived syngas contains a variety of contaminants, including condensable hydrocarbons (tars), particulates, alkalis, and, to a lesser extent, sulfur and nitrogen compounds such as hydrogen sulfide, carbonyl sulfide and hydrogen cyanide. These contaminants must be removed prior to the utilization of the syngas in the conversion options described above, with the exception of close-coupled boilers.

For high temperature, high pressure applications such as gas turbines or chemical synthesis processes, the removal of contaminants would ideally occur at the same temperatures and pressures as the gasification process. This method of contaminant removal, referred to as hot gas cleanup, retains the thermal energy of the gases and, in the case of pressurized gasification, may eliminate the necessity of a costly and power-intensive gas compressor. At present, however, there has been little commercial demonstration of successful hot gas cleanup. Experience with hot gas cleanup in DOE-funded coal IGCC projects is poor. The Pinon Pine hot gas cleanup system failed and the Polk County system was never even used. Much of the problems with hot gas cleanup at coal IGCC facilities have been related to sulfur removal systems and ceramic candle filters. However, removal of tars and alkalis will be a greater challenge for biomass IGCC facilities and high temperature methods to remove these compounds must be improved. Current research for biomass-derived syngas cleanup is focused on the catalytic cracking of tars, sintered metal candle filters for particulate removal, and high-temperature alkali capture.

The majority of biomass gasification projects in operation or under development employ low-temperature (< 100°F) contaminant removal, known as cold gas cleanup. In this method, the gases are cooled to allow contaminants such as tars and vapor-phase alkali to condense out of the syngas, and particulates are removed through conventional baghouses or electrostatic precipitators. If necessary, wet scrubbers are used for the capture of remaining tars and particulates, and solvents are employed to remove sulfur from the gas stream. Cold gas cleanup systems are considered commercial technologies.

2.1.7 Issues Associated with Firing Syngas in Combustion Turbines

As mentioned above, syngas must be free of contaminants and pressurized to the appropriate pressure prior to its introduction to the combustion turbine. For gasification systems operating at atmospheric pressure, a compressor must be used to increase the pressure of the syngas to the turbine inlet pressure (plus an allowance to overcome pressure drops from the compressor discharge to the turbine inlet). For pressurized gasification systems, gas compression may be avoided if the system operates at an appropriate pressure and the syngas pressure can be maintained throughout the gas cleanup process. However, due to the lack of demonstrated high-temperature, high-pressure cleanup systems for biomass gasification, it is likely that any gasification system would require the inclusion of a compressor to provide the syngas at the turbine inlet at the appropriate pressure.

In addition, to syngas pressure concerns, biomass-derived syngas can have different combustion properties depending on whether the gasifier is air-blown or oxygen- or steam-blown. In either case, however, these properties are different than the properties of natural gas and significant modifications are required to fire syngas in pre-existing combustion turbines originally designed to fire natural gas.

In the case of air-blown gasification, syngas typically has a volumetric heating value of 150-200 Btu/ft^3, which is significantly lower than the heating value of natural gas (approximately 1000 Btu/ft^3). In the case of oxygen- or steam-blown gasification, the volumetric heating value of the syngas increases to 300-400 Btu/ft^3. A greater volume of syngas must be combusted (relative to natural gas) to provide the necessary heat input, and therefore, nozzle orifices must be enlarged to allow the larger volume of syngas into the combustor and maintain the proper pressure drops through the system. The increased mass flow through the system generally produces more work than a natural gas fired turbine. Figure 2-4 shows the increased power output for a modern Siemens turbine operating on syngas as a function of ambient temperature.

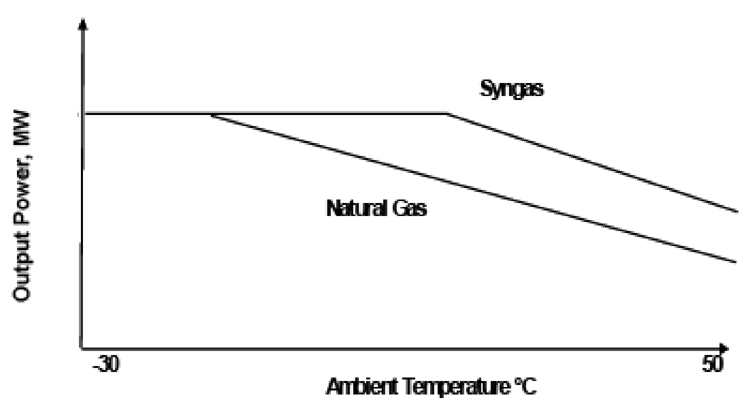

Figure 2-4. Output Power versus Ambient Temperature (Source: Siemens).

Syngas can have a relatively high hydrogen content, which increases flame speed and decreases flame stability. Because of these factors, a conventional (diffusion) combustor must be used rather than a low-NOx (pre-mixed) combustor. NOx control is accomplished by adding a diluent (such as nitrogen or steam) to the syngas.

The concerns regarding firing syngas in combustion turbines originally designed to fire natural gas may be mitigated by cofiring or blending syngas with natural gas. Turbine manufacturers are increasingly designing their turbines to fire a mixture of the two. Figure 2-5 shows the range of capability that GE is currently offering on many of their larger scale turbines. It is possible that few modifications would be required to cofire a mixture of syngas and natural gas in existing combustion turbine; it is recommended that this issue be discussed with turbine manufacturers in the next phase of this study.

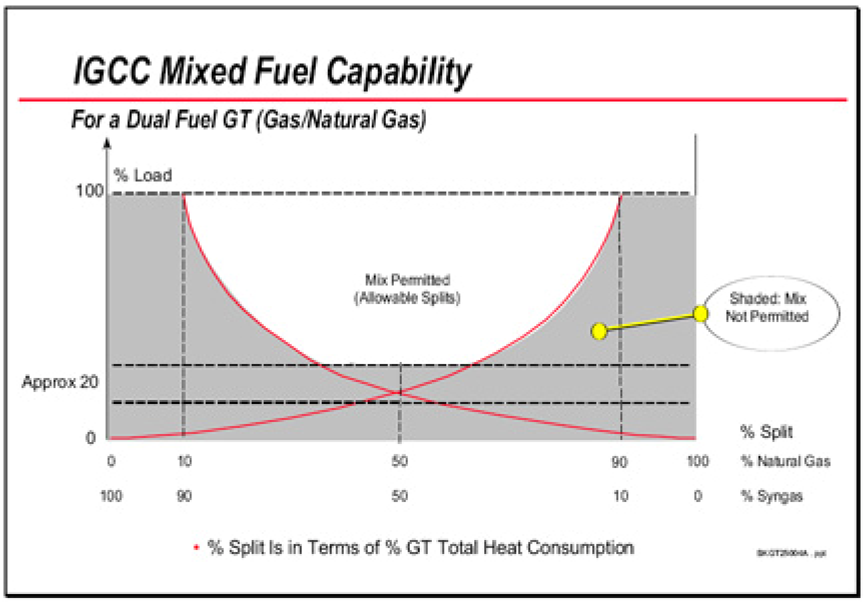

Figure 2-5. Mixed Fuel Firing (Source: General Electric).

2.1.8 Biomass Integrated Gasification Combined Cycle

Up until the most recent focus on chemical synthesis applications, one of the principal focus areas for biomass gasification technology developers has been biomass integrated gasification combined cycle (IGCC). IGCC power plants are suitable for larger scale biomass conversion. Such plants consist of a gasifier or pyrolyzer that provides syngas to a standard gas turbine. The gas turbine burns the fuel and generates power. Sensible energy in the hot exhaust of the turbine can be recovered in a heat recovery steam generator (HRSG). Steam generated by the HRSG can be used for cogeneration and/or to power a steam turbine.

Commercial-scale IGCC coal-fired power plants are considered to be the most efficient solid-fuel technologies in operation today. Further development of this technology for biomass would benefit from improved gas clean-up. The most difficult part of the process is providing a clean gas to the gas turbine. Research in this area, specifically hot gas clean-up, is intensive. Biomass gasification systems should be lower cost than similar size coal IGCC plants because (1) the high reactivity (volatility) of biomass reduces gasifier costs, and (2) the low sulfur content of biomass reduces gas clean-up system costs. However, as with other biomass energy systems, gasification economics are hurt by difficulty reaching very large scales due to fuel supply constraints. Net conversion to electricity is projected to be approximately 35 percent for biomass IGCC plants, compared to 20 to 25 percent for conventional biomass combustion plants.[1]

The potentially significant increase in efficiency has made biomass IGCC attractive to many developers and governments. Unfortunately, biomass IGCC projects around the globe have struggled to reach commercialization:

- **ARBRE, UK Project –** The 8 MW ARBRE IGCC project located near Eggborough in the United Kingdom was designed to use a TPS atmospheric circulating fluidized bed gasifier. The project included gas clean-up and a 5 MW Typhoon gas turbine. The project was to be fueled with locally grown wood. The project, originally estimated to cost over $40 million, was declared bankrupt after failing to achieve commercial operation. It was recently bought for around $4 million. Future status is unclear.
- **FERCO, Vermont Gasification Project –** The Vermont biomass gasification project, developed by Battelle/DOE and Future Energy Resources Corporation (FERCO), was only partially more successful. The project was sized to gasify up to 200 tpd of wood chips. Although FERCO did announce some successful extended gasification trials, the project was never advanced to the IGCC stage (the syngas had been cofired in the adjacent wood stoker boiler). FERCO declared bankruptcy in 2002 after investing $10 million of its own money into the project (in addition to more than $30 million U.S. government funds). However, FERCO has now reorganized, and is actively seeking to sell gasification equipment again.

[1] The higher efficiency of IGCC plants could result in lower delivered cost of biomass than that of a conventional biomass plant of the same size. This lower cost of biomass is possible because less biomass is required and may reduce the distance that biomass must be transported. The significance of this cost reduction would be site specific and would depend on the size of the facility and the location of biomass supplies relative to the facility.

- **Hawaii Gasification Project –** The Hawaii gasification demonstration project was a pressurized air/oxygen gasifier designed to process up to 100 tpd of bagasse. The gasifier was designed by the Gas Technology Institute (GTI). The project was to include hot gas clean-up to allow the syngas to be fired in a gas turbine. The project had operated for about 500 hours but was halted due to ongoing problems with material handling and cessation of DOE funding. Carbona (formerly known as Tampella) has licensed the GTI gasifier design and is seeking to develop new projects with the technology.
- **Värnamo, Sweden –** The only large-scale IGCC project that has run for any appreciable length of time is the project in Värnamo, Sweden. The gasifier ran for more than 7,000 hours between 1993 and 1999. The demonstration project produced 6 MW of electricity and thermal energy. It was developed by Sydkraft AB and Foster Wheeler. The gasifier was a pressurized, air-blown circulating fluidized bed designed to gasify wood and wood waste. The project included warm gas clean-up and firing in a combustion turbine provided by European Gas Turbines. The project was not designed to be a full-scale commercial facility, and was closed in 1999 after completing demonstration trials.[2]

2.1.9 Making Advanced Gasification Projects Successful

The recent attempts to demonstrate IGCC have frustrated the biomass industry. Difficulties have been related not so much to the gasification process itself, but to supporting ancillary equipment, such as fuel handling and gas cleanup. Project budgets have generally not included enough contingency funding to overcome these issues. Given enough time, expertise, and capital, there are engineering solutions to these problems. Close cooperation with technology suppliers and proper attention to ancillary systems will be necessary to make advanced biomass gasification projects successful. However, until there are proven, operating reference plants to visit, investors and lenders will remain skeptical of the technology.

Despite the recent problems with technology demonstration, the promise of (1) higher efficiency power production offered by IGCC or (2) the potential for lower cost ethanol production via a chemical synthesis platform remains attractive. One possible method to overcome the risks associated with advanced gasification processes is to develop a phased commercial project. In this approach, the various elements of the process would be built and proven sequentially prior to the next phase being

[2] UC Davis, "Technology Assessment for Biomass Power Generation," October 2004, available at http://biomass.ucdavis.edu/pages/reports/UCD_SMUD_DRAFT_FINAL.pdf.

implemented. For example, a project could be developed by building and proving the gasifier in a close-coupled boiler application first, prior to adding gas cleanup and advanced gas conversion processes. The economics and permitting of the project would be facilitated if an existing fossil fuel boiler could be identified to host the project.

The potential for advanced applications of gasification technology make the technology promising and worthy of further consideration for some applications. However, unlike combustion systems, for which there are commercial suppliers of proven technology, advanced full-scale (i.e., 20 MW of electrical generation or greater) gasification systems are still considered developmental technologies. Although the first full-scale commercial systems for IGCC or chemical synthesis applications may be operational within five years, it will likely take 5 to 10 years before commercial systems are widely offered. This makes the technology less attractive to investors with shorter payback timeframes. On the other hand, investors who are more receptive to the risks and rewards associated with new technologies may find gasification to be an attractive approach.

2.1.10 Vendors of Biomass Gasification Technologies

Currently, there are several suppliers of commercial gasification equipment. The most prominent of these companies include:

- Foster Wheeler
- Ebara
- Energy Products of Idaho (EPI)
- Primenergy
- Frontline Bioenergy
- Emery Energy
- Chiptec
- Nexterra

There are also numerous emerging vendors of advanced technologies that offer significant benefits. The companies that offer the most promise for future applications include:

- Carbona
- SilvaGas (FERCO)
- Clean Energy/Pearson
- Thermochem/MTCI

Key characteristics of the listed gasification system vendors are summarized in Table 2-1.

Foster Wheeler has supplied circulating fluidized bed (CFB) gasification systems for biomass and waste gasification projects in Belgium, Finland, and Sweden through its Finnish arm, Foster Wheeler Energia Oy. Feedstocks utilized in these projects include wood and recycled products, and the resulting syngas was typically cofired in oil-fired boilers. A system at the Coresco recycling plant in Varkaus, Finland, consumed 50 tons per day of recycled materials, producing 40 MW_{th} of syngas. A biomass IGCC system supplied by Foster Wheeler was successfully demonstrated at Varnamo, Sweden, as mentioned above. The biomass activities of Foster Wheeler in the United States have focused primarily on direct combustion technologies rather than gasification.

The Ebara Corporation offers a close coupled gasification/combustion system known as the TwinREC process. The TwinREC process has been commercially implemented for less than 10 years. The company has designed and installed thirteen systems in Japan and one in Malaysia, primarily for the processing of municipal solid waste (MSW), refuse derived fuel (RDF), and auto shredder waste (ASW). The largest project, located in Aomori, Japan, consists of two TwinREC systems; each of these systems has a throughput of 225 tons of waste per day, generating 40 MW_{th} of thermal energy. Ebara is currently developing an indirectly-heated gasification system consisting of two chambers within one reactor. The two chambers serve to separate the gasification and combustion processes, which increases the heating value of the syngas. Ebara has constructed a 15 ton per day pilot system of their indirectly-heated gasification system. It should be noted, however, that at present Ebara is not actively marketing its products in the United States.

Energy Products of Idaho (EPI) supplies bubbling fluidized bed (BFB) gasification systems. Since their inception in 1973, EPI has developed technologies for processing biomass and other alternative fuels; these technologies include combustion and gasification systems. The design of EPI's gasification systems are based on their direct combustion systems; the gasification systems are operated sub-stoichiometrically and overfire air systems are removed to generate syngas rather than the products of combustion. The company's gasification systems are commercially available and range in size from 1 MW_e to 50 MW_e equivalent energy output, although the largest installed gasification system provides approximately 6 MW_e.

Primenergy provides updraft fixed bed gasification systems that are coupled with staged combustion systems. The syngas from the gasifier is of low heating value, around 100 Btu/ft^3. Since 1995 Primenergy has completed six biomass-fired gasification facilities in the U.S. and one in Italy, ranging in processing capacity from 67 to 550 tons per day. These facilities produce process steam, hot air for drying or electricity from wood waste, rice husks, and other waste fuels. The largest plant employing a Primenergy gasification system produces 12.8 MW_e.

Table 2-1. Sample List of Biomass Gasification Technology Vendors.

Vendor	Gasification Process	Syngas Heating Value[a]	Gasifier Throughput (tons/day)[b]	Commercial Status
Foster Wheeler	Atmospheric Fluidized Bed	Low-Btu	50	Commercial
Ebara	Atmospheric Fluidized Bed	Low-Btu	225	Commercial
Energy Products of Idaho	Atmospheric Fluidized Bed	Low-Btu	6 MW_e [c]	Commercial
Primenergy	Updraft Fixed Bed	Low-Btu	550	Commercial
Frontline Bioenergy	Atmospheric Fluidized Bed	Low-Btu	70[d]	Early Commercial
Emery Energy	Updraft Fixed Bed	Low-Btu	25	Early Commercial
Chiptec	Cross-Draft Fixed Bed	Low-Btu	50	Commercial
Nexterra	Updraft Fixed Bed	Low-Btu	35	Commercial
Carbona	Pressurized Fluidized Bed	Low-Btu	100	Demonstration
SilvaGas Corporation (FERCO)	Indirectly-Heated Fluidized Bed	Medium-Btu	350	Demonstration
Clean Energy/Pearson	Indirectly-Heated Steam Reforming	Medium-Btu	50	Demonstration
ThermoChem Recovery International (MTCI)	Indirectly-Heated Fluidized Bed	Medium-Btu	100	Demonstration

Notes:
[a] Syngas with a typical heating value in the range of 150-250 Btu/ft^3 are classified as Low-Btu gas. Syngas with a typical heating values in the range of 300-400 Btu/ft^3 are classified as Medium-Btu gas.
[b] Gasifier throughput represents the maximum biomass throughput (in tons per day) that the process has successfully demonstrated.
[c] EPI's largest gasification unit generates approximately 6 MW_e, but the company did not indicate the biomass throughput necessary to achieve this output.
[d] Frontline Bioenergy is developing a 70 ton per day system for Chippewa Valley Ethanol Company in Benson, MN. This unit is not yet operational.

Frontline Bioenergy supplies bubbling fluidized bed gasification systems, providing low-Btu syngas. The company, formed in 2005, is focused on the integration of gasification systems with ethanol production facilities to displace natural gas consumption. Frontline is currently developing a 70 ton per day system for the Chippewa Valley Ethanol Company, located in Benson, Minnesota. The project was scheduled to come online in the first quarter of 2007, but developers are currently experiencing delays with permitting.[3] When the 70 ton per day system becomes operational, it will offset 25 percent of the natural gas consumption of the facility, which produces 45 million gallons of ethanol per year.

Emery Energy is developing a modified updraft gasification process. Based on results obtained from tests conducted on a 25 ton per day pilot plant, the company claims "extremely low tar and oil carryover for fixed bed gasifiers" and "control of sulfur species in the syngas." The process incorporates aspects of entrained-flow gasification[4], which increases the heating value of the syngas. The relatively low tar production and increased heating value of the syngas are advantageous for combustion turbine applications.

Chiptec and Nexterra are currently offering industrial-scale (i.e., less than 10 MW_e) gasification systems for small power generation and/or cogeneration. These companies are unlikely to provide utility-scale systems, but they have been included due to their status as active commercial gasification system vendors.

Carbona is the current supplier of the pressurized fluidized bed technology developed by the Gas Technology Institute (GTI). The company's most recent project is a cogeneration facility providing 5.5 MW of electricity and 11.5 MW of thermal energy for Skive, Denmark. The activities of Carbona should be monitored due to the potential benefits of pressurized fluidized bed gasification for IGCC applications.

SilvaGas Corporation, formerly known as FERCO Enterprises, provides a unique dual-bed, atmospheric circulating fluidized bed gasification system capable of producing a medium Btu gas (heating value of approximately 450 Btu/ft^3). Feedstocks tested to date include various forms of wood, RDF, energy crops, switch grass, paper mill sludge, and crop residues. The largest demonstration of the gasification process occurred at the McNeil Station in Burlington, Vermont, where a 350 ton per day gasification system was successfully operated (with syngas fired in an adjacent boiler). The process, known as the SilvaGas process, offers potential for gas turbine applications. While the gasification process has been demonstrated at near-commercial scale, the gas turbine interface has not been demonstrated, and there are currently no operational commercial sites. In spite of

[3] "Gasifier project awaits MPCA permit, design being finalized," West Central Tribune Online. Accessed at www.wctrib.com/articles/index.cfm?id=15490&section=homepage on January 28, 2007.
[4] Phillips, Benjamin D. "Technical and Economic Evaluation of a 70 MWe Biomass IGCC Using Emery Energy's Gasification Technology." Accessed at: www.gasification.org/Docs/2003_Papers/33PHIL.pdf on January 29, 2007.

the lack of successful demonstration for gas turbine applications, the activities of the company should be monitored.

Clean Energy has licensed a gasification process developed by Pearson Technologies, Inc. (PTI). The company was formed in 2001, and is developing various products from gasification and Fischer-Tropsch (FT) processes, including syngas for heat and/or power, biofuels (e.g., ethanol, methanol and synthetic diesel), and other chemical uses. The Clean Energy gasification system is an indirectly fired, entrained flow design. The Clean Energy process does not expose the feedstock to oxygen or air; the feedstock is entrained in a stream of superheated steam, which results in medium-Btu syngas. Clean Energy claims that the entrained-flow process greatly reduces tar production, and under some operating conditions, no tars are produced. The greater heating value and lower tar content of the syngas from the Clean Energy process are advantages for the system, particularly for potential combustion turbine and FT applications. Thus far, the largest system that Clean Energy has successfully demonstrated is a 50 ton per day system.

ThermoChem Recovery International is the current supplier of the process initially supplied by MTCI. In this process, gasification occurs within a steam-blown fluidized bed, and heat is supplied by a number of heat exchangers immersed within the fluidized bed. A portion of the syngas is combusted within the heat exchanger tubes, which ThermoChem refers to as "pulsed heater resonance tubes." A schematic of the process is shown in Figure 2-6.

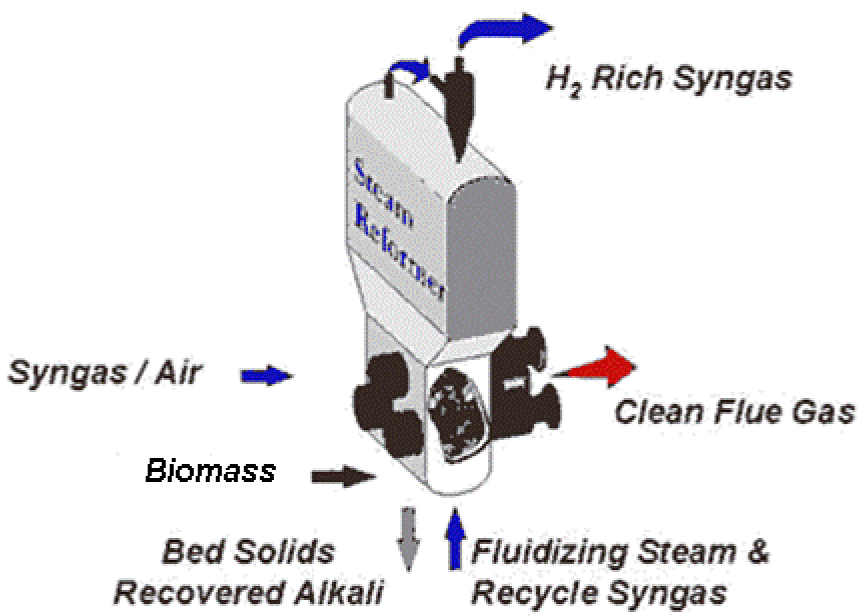

Figure 2-6. Schematic of the ThermoChem (MTCI) Process.

Because of the separation of the combustion and gasification reactions, the ThermoChem process yields a medium-Btu syngas. The process is currently being marketed by ThermoChem for the paper and pulp industry as a means of utilizing black liquors; the largest of these projects are 100 ton per day projects located at Georgia Pacific's Big Island facility and at a Norampac facility in Trenton, Ontario.

2.1.11 Pyrolysis Technologies

Pyrolysis is the thermal decomposition of material in the absence of oxygen to produce a wide variety of products. It is an emerging biomass conversion process. To trace the word back to its Latin roots, pyrolysis is the breaking down (*lysis*) of a material with heat (*pyro*). Pyrolysis is performed with very little or no oxygen, and has been termed as "anaerobic combustion." Pyrolysis produces a variety of products, as described in the simple equation below:

Fuel (solid) + Heat → Syngas + Char + Oil + Tar

There are different types of pyrolysis, and the differences affect the end products of the process. Slow pyrolysis is the most conventional approach. The term "slow" is derived from the low fuel heating rates (less than 20°F/s). Additionally, temperatures are relatively low (less than 1,000°F), and char and oil/tar are the primary products. Fast pyrolysis, on the other hand, involves quick heat-up rates (20-200,000°F/s), and high temperatures (above 1,100°F). Rapid processing of the fuel freezes chemical reactions and allows for greater gas production at the expense of char, oil, and tar. Another classification, flash pyrolysis, is similar to fast pyrolysis in heat-up rates but occurs at lower temperatures (750-1,100°F). Flash pyrolysis focuses on the production of liquid tar and oil at the expense of gas and char. A general flow diagram for a typical pyrolysis system is included in Figure 2-7.

Perhaps the most promising product from pyrolysis is bio-oil (see Figure 2-8). Bio-oil has potential applications as a replacement fuel for petroleum in boilers (and possibly heavy duty industrial gas turbines) or as a precursor for the creation of high value specialty chemicals (e.g., levoglucosan).

Pyrolysis technology is generally in the early phase of commercialization. One U.S. company, Renewable Oil International, is in the development and demonstration phase with their pyrolysis technology. Two Canadian companies, the Ensyn Group and Dynamotive, have commercial 100 ton per day pyrolysis plants that are currently operating. These facilities produce approximately 0.65 to 0.72 pounds of pyrolysis oil per pound of incoming feedstock, as shown in Table 2-2.

Given that pyrolysis oil has about 6500 to 8500 Btu/lb, a pyrolysis facility that processes 100 ton per day of feedstock would produce enough fuel to generate roughly 3 to 4 megawatts of electric power.

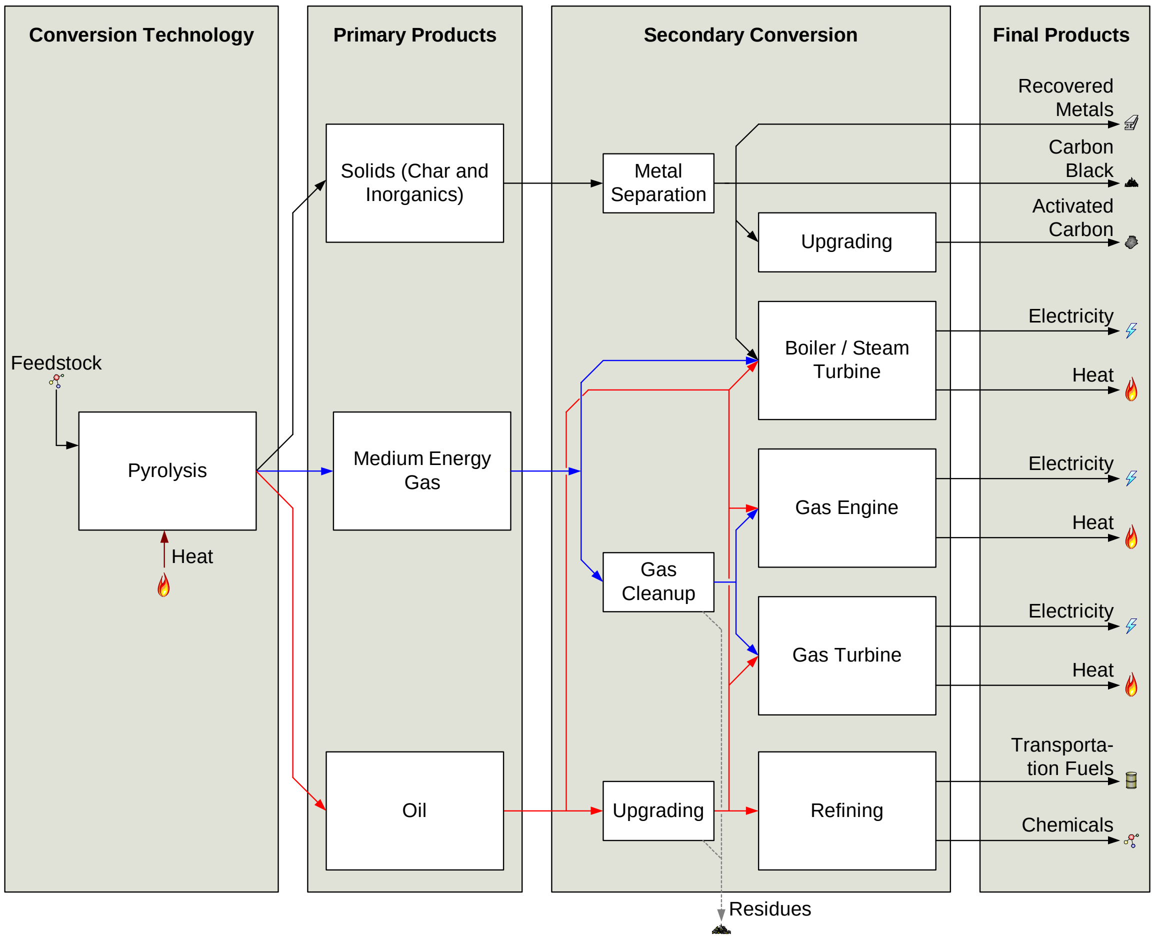

Figure 2-7. General Pyrolysis Process Flow Options.

Figure 2-8. Bio-oil Produced from Pyrolysis (Source: Iowa State University).

Table 2-2. Sample List of Biomass Gasification Technology Vendors.

Vendor	Pyrolysis Process	Maximum Throughput (tons/day) [a]	Pyrolysis Oil Yield (%) [b]	Commercial Status
Dynamotive	Fast Pyrolysis	100	65-72	Commercial
Ensyn	Fast Pyrolysis	100	65-72	Commercial
Renewable Oil International	Fast Pyrolysis	Unknown	Unknown	Demonstration

Notes:
[a] Throughput represents the maximum biomass throughput (in tons per day) that the process has successfully demonstrated.
[b] Pyrolysis Oil Yield is the percentage of mass converted from solid biomass to bio-oil (i.e., pounds of oil per pound of biomass).

2.1.12 Bioreactor Technology

A bioreactor is any device or system that supports biologically active anaerobic or aerobic environments. A bioreactor is typically a vessel in which chemical processes which involve organisms or biochemically active substances derived from such organisms are carried out.

One of the recent technologies that is being looked into is the algae bioreactor. This technology uses algae to remove CO_2 from power plant emissions. The carbon-rich algal biomass with sufficient quality and concentration of oils and starch content is then converted into various kinds of biofuel using technologies such as gasification, extraction and transesterification, fermentation, anaerobic digestion or drying to produce transportation grade biodiesel and bioethanol. Algae bioreactors are being pioneered by GreenFuel Technologies Corporation (GFTC) which has a patented Emissions-to-Biofuels™ (E2B™) process. According to GFTC's website, GFTC installed its first field unit on a 20 MW cogeneration facility at the Massachusetts Institute of Technology in 2004. Its second, larger unit was commissioned at a 1,060 MW combined cycle facility in 2005 for the Arizona Public Service's (APS) Redhawk Power Plant in Arlington, AZ. GFTC's bioreactor productivities suggest annual yields of 5,000-10,000 gallons of biodiesel and a comparable amount of bioethanol per acre. Biodiesel and/or bioethanol can then be combusted to produce power. APS provided a news release on November 30, 2006 and revealed that GFTC and APS have been conducting a field assessment program over the past 18 months, and have moved into the next phase of study with the construction of an Engineering Scale Unit that will be completed in first quarter of 2007.

2.2 Summary

A variety of gasification and pyrolysis technologies offer promise for future biomass power applications, but gasification technologies offer greater near-term potential for application to facilities considering combustion turbines for their biomass projects. To develop gasification projects successfully, issues related to gas cleanup, allowable mixes of syngas and natural gas, and potential modifications to the combustor will have to be addressed. Gasification, pyrolysis and bioreactor technologies have been in existence for several years, but they are getting into be commercially available for energy generation only recently and will therefore likely qualify as advances biomass conversion technologies.

3.0 Conventional Technologies With Advanced Enhancements

There are several proven conventional external direct combustion systems for burning biomass fuels that have been commercially available for more than 10 years. These include the following:

- Stoker grate boilers (dumping grate, traveling grate, vibrating grate, etc.);
- Bubbling fluidized bed boilers;
- Circulating fluidized bed boilers; and
- Pulverized fuel suspension fired boilers.

Other conventional internal combustion systems that have also been used include combustion turbines and reciprocating internal combustion engines that fire biodiesel, digester gas and landfill gas and other liquid or gaseous biofuels. The following sections provide a discussion on design and combustion performance enhancements that have become commercially available in the past 10 years, which when implemented on conventional biomass conversion technologies, could potentially qualify each of these technologies as an “advanced biomass power conversion technology” under the RPS and may help in meeting the “low-emission” criterion for RPS eligibility.

3.1 Conventional Internal Combustion Engines and Turbines

The body of experience dealing with biofuels such as biodiesel and ethanol in electric generation applications is still relatively small though other biofuels, such as digester gas and landfill gas, have been used for well over ten years in combustion turbines and reciprocating internal combustion engines. This section concentrates on biodiesel and explores if any advancements in technology are required for firing biodiesel.

Several entities have begun working with manufacturers to explore biodiesel’s compatibility with power generation equipment. Over the next few years it is expected that biodiesel-fueled electric generation will become better known.

3.1.1 Experience with Power Generation Using Biofuels

There are a few examples of using biofuels for electric power generation:

- **Southern States Power –** in 2001 the University of California Riverside installed three 2 MW Cummins reciprocating engines fired by biodiesel. The 6 MW pilot project was intended for emergency backup during the 2001 energy crisis. It is believed that the facilities are no longer operating.

- **Rawhide Energy Station –** Platte River Power Authority's Rawhide coal plant in Colorado began using biodiesel in 2006 for start-up of its coal-fired Rawhide energy station. The biodiesel replaces petroleum diesel normally used for startup.
- **New York Power Authority –** In October, 2006, New York Power Authority (NYPA) undertook two days of test burning biodiesel blended with heating oil in the Charles Poletti Power Project in Queens.[5] The 885 MW plant normally uses natural gas or heating oil. For the test burns, soybean-based fuel was blended with No. 6 fuel at concentrations between 5 and 20 percent. A total of 100,000 gallons of biodiesel was used in the test burns, making it the largest use of biofuels on any single occasion in the US according to NYPA. Complete data from the tests is being prepared by the Power Authority and the Electric Power Research Institute. Initial data show some efficiency gains and emission reductions compared to standard fuel oil. NYPA had obtained a permit waiver from the New York State Department of Environmental Conservation to permit the biofuel testing.
- **Biofuels Power Corp –** On March 5, 2007, Biofuels Power Corp. announced that it has begun to generate and sell electricity produced from a biodiesel-powered plant in Oak Ridge North, Texas.[6] This is the first power plant in the country to run entirely on biodiesel. The facility uses three diesel Caterpillar engine generators with a combined total capacity of five MW. Biofuels Power has plans to build more biodiesel-powered generating plants. The company is building a 10 MW turbine-based power plant at the Safe Renewable refinery site to provide electricity for Entergy Corp. customers in East Texas and Louisiana. The biodiesel is produced by a Safe Renewables Corp. refinery located two miles away from the generating station. The refinery produces biodiesel from soy, cottonseed and canola oils, as well as animal fats.
- **Kauai Island Utility Cooperative (KIUC) –** KIUC is currently testing biodiesel blends in one of their four existing 8 MW SWD reciprocating engines. These No. 2 fueled engines are generally in intermediate, load following service.
- **Hawaiian Electric Company (HECO) –** HECO and its subsidiaries have probably the most ambitious plans for use of biofuels for electric generation. In early 2007 HECO issued a request for proposals for supplies of ethanol or biodiesel to fuel its planned 110 MW Campbell Industrial Park Generation Station outside of Honolulu. The power plant will be a combustion turbine peaking station and could use up to 20 million gallons of biofuel annually. Due to an

[5] http://www.nypa.gov/press/2006/061109b.htm
[6] http://houston.bizjournals.com/houston/stories/2007/03/05/daily2.html

agreement with state regulators, the plant will burn exclusively biofuels. Siemens is providing the turbine for the project. The plant is expected to come online in 2009.

- **Maui Electric Company (MECO) –** MECO, sister utility of HECO, recently announced the construction of a new 40 million gallon per year biodiesel facility to fuel its generators at its Ma'alaea Power Plant. This power plant has 15 diesel units, 1 dual train combined cycle, and 2 combustion turbines. MECO is currently investigating modifications necessary to convert the units to biodiesel firing. In total, MECO consumes over 70 million gallons of fuel oil annually. Initially, imported palm oil will be the feedstock. The plant, to be operational in 2009, will be owned by BlueEarth Maui Biodiesel LLC, a partnership between BlueEarth Biofuels LLC and a new nonregulated subsidiary of HECO.[7]

3.1.2 Biodiesel Use in Conversion Technologies

As with other liquid fuels, biodiesel can be fired in a variety of conversion technologies, including reciprocating engines, combustion turbines, and boilers.

Reciprocating Engines

The extensive testing and experience to date with the use of biodiesel in vehicle engines provides a strong base of knowledge of relevance to the use of biodiesel in stationary diesel engines.

US engine manufacturers are developing a standard specification for blends to be burned in their engines, according to William Rohner of Caterpillar.[8] Most manufactures will honor equipment warrantees for ASTM D6751 biodiesel blends up to B5, with some covering up to B20 (Cummins). Most manufacturers neither encourage nor discourage using biodiesel, but consider engine failures resulting from biodiesel usage a responsibility of the fuel supplier or engine operator.

Straight vegetable oil is a viable fuel for larger, slow speed reciprocating engines. These fuels are often designed to burn heavier fuels, such as No. 6 fuel oil; SVO is relatively “easy” by comparison. Caterpillar, for example, will provide warrantees and guarantees for their large engines (up to 15 MW) on SVO or 100 percent biodiesel.

Combustion Turbines

Combustion turbine manufacturers are in the early stages of investigating biofuel usage in their equipment. Solar Turbines does state that biodiesel may be used alone or

[7] Honolulu Advertiser, “$61 Million Biodiesel Plan Outlined,” available at: http://the.honoluluadvertiser.com/article/2007/Feb/18/ln/FP702180354.html

blended with petroleum-based diesel fuels. The HECO Campbell Industrial Park project will use a Siemens combustion turbine fueled with biodiesel (or ethanol).

Boilers

Oil is no longer in widespread use for utility power boilers, so there has been little attention on alternative fuels. Large boiler manufacturers have kept relatively quiet regarding the impacts of biodiesel in their equipment. Other than the NYPA and Rawhide examples given previously, there does not appear to be a lot of experience burning biodiesel in boilers for large scale electric applications. Nevertheless, boilers would seem to be one of the more readily adapted technologies for burning biofuels.

3.1.3 New vs. Existing Equipment

Although power equipment manufacturers are aware of the increasing interest of using biofuels in their equipment, they do not yet market any equipment models designed expressly for biofuels. Currently, both new and existing equipment may require the same modifications and considerations for using biodiesel. The principal consideration for the use of new versus existing equipment is likely to be the support of the manufacturer for equipment warrantees and guarantees.

3.1.4 Equipment Changes to Accommodate Biodiesel

Generally speaking, the changes required to fire biodiesel and biodiesel blends are relatively small. Biodiesel has very similar properties to diesel and most equipment should be able to handle blends with relatively modest modifications.

Because biodiesel has about 10 percent lower energy content per gallon than No. 2 diesel fuel, higher flow is required to make equivalent power. A B100 fuel (100 percent biodiesel, also called "neat") may require 10 percent greater volumetric flow to produce the same rated equipment capacity. Fuel system components may require modification to accommodate this lower energy content and higher flow. The impact is lessened for blends. A B20 blend, for example, would only require 2 percent higher flow. As the biodiesel blend level is lowered, energy content differences diminish. Blends of B5 or less do not cause noticeable engine performance differences compared to No. 2 fuel.

Handling and storage of biodiesel may require some adjustments from petroleum diesel. Neat biodiesel can be corrosive to many non-metallic equipment components, specifically seals and other polymers. Engine manufacturers have recommended that seals be replaced by a chemical-resistant fluoroelastomer, such as Teflon® or Viton®.

[8] Cogeneration & On-Site Power Production Magazine, January-February 2007

Additionally, certain metals (brass, bronze, copper, lead, tin, and zinc) may promote biodiesel oxidation. Equipment containing these metals should be replaced with aluminum, stainless steel, or carbon steel. Biodiesel blends containing less than 20 percent biodiesel exhibit significantly diminished adverse effects on incompatible materials. At levels as low as B2 (2 percent biodiesel mixed with 98 percent No. 2 fuel), adverse effects are virtually non-existent.

Biodiesel is less stable than No. 2 diesel and may require additives to prolong fuel life in long-term storage (greater than 6 months). Although fuel suppliers can provide oxidation stability additives, using biodiesel in rarely-operated critical equipment, such as emergency backup generators, should be done with caution.

Neat biodiesel gels faster than No. 2 fuel in cold climates. To deal with this issue, Europe has enacted a cold filter plugging point (CFPP) standard for biodiesel of minus 12 degrees Celsius. Fuel additives can be mixed with biodiesel to decrease the temperature at which it gels. Cold weather gelling is not a problem if a fuel heater is used or the fuel is stored in a building.

3.2 Conventional Direct Fire Combustion Technologies

The selection of combustion technology for a given application is influenced by the size of the unit, the characteristics of the biomass fuel, required emissions levels, and the amount and type of maintenance effort the owner will accept. Although stoker boilers are the most widely used combustion technology for biomass, they are not always the most appropriate technical choice. Fluidized beds are good choices in general because they can tolerate wide variations in fuel moisture content and size and the fluidized bed boiler designs are continuously being fine tuned. Their lower operating temperatures also minimize concerns related to slagging and fouling. This allows fluidized beds to take advantage of low quality opportunity fuels that stokers might not be able to fire (such as wood from storm damaged trees in Florida that can have significant amounts of sand and dirt contamination). An additional advantage of fluidized beds is their inherently lower emissions and the ability to easily add sorbent to the bed to allow capture of sulfur.

The choice of combustion technology has a negligible effect on overall plant heat rate. The turbulent action of the bed results in higher combustion efficiencies for fluidized beds than those of stoker boilers; however, this increased combustion efficiency is offset by the high auxiliary power consumption of the fluidizing air fans. Net plant heat rates for biomass power facilities are much more dependent on steam cycle design. Typically, biomass facilities with nominal capacities of 20 MW_e to 30 MW_e have heat rates of approximately 13,500 Btu/kWh, while biomass facilities with capacities approaching 50 MWe can reduce heat rates to 12,500 Btu/kWh by integrating multiple feedwater heaters into the steam cycle design.

Considering economics, the choice of technology to use is somewhat related to size, as the capital costs of stoker, bubbling fluidized bed (BFB) and circulating fluidized bed (CFB) technologies scale differently. For facilities generating 50 MW of electrical generation or less, the cost effective combustion technologies are stoker boilers and bubbling fluidized beds (BFBs). Comparing stokers and BFBs, stokers have lower capital costs (10 to 20 percent less) and operation and maintenance costs than BFBs, but have greater emissions (see Table 3-1).

Within the size range of 50 MW to 100 MW, BFBs and CFBs are typically the most cost effective option. Recent discussions with boiler vendors indicate that for biomass-only generation facilities in this size range, BFBs are the optimal technology. If the co-combustion of multiple fuels (e.g., a mixture of woody fuels and poultry litter or a mixture of biomass and fossil fuels) is desired, either BFBs or CFBs would be reasonable options to consider.

Table 3-1 compares the features of stoker and fluidized bed (bubbling and circulating) biomass boilers.

3.2.1 Vendors of Direct Combustion (Biomass) Technologies

Direct combustion technologies are provided by a large number of vendors. Some of the prominent vendors that offer services in U.S. markets include the following:

- Foster Wheeler
- Alstom
- Babcock & Wilcox
- Kvaerner
- Energy Products of Idaho (EPI)
- AE&E Von Roll
- Babcock Power
- Detroit Stoker
- McBurney
- Indeck-Keystone

Table 3-1. General Comparison of Typical Stoker and Fluidized Bed Technologies.

	Stoker Technologies	BFB and CFB Technologies
Efficiency Issues		
Boiler Efficiency	65-85	65-85
Auxiliary Power Consumption	7-12%	8-14%
Cost Issues		
Typical Total Plant Capital Cost	$2,500-$3,000/kW	$2,750-$3,500/kW
Operating and Maintenance Cost	$15-20/MWh	$16-22/MWh
Fuel Issues		
Fuel Flexibility	Good	Very Good
Ability to Handle High Moisture	Good	Very good
Slagging and Fouling Potential*	Fair with proper design	Good
Uncontrolled Emissions		
NOx Emissions	0.2 to 0.4 lb/Mbtu	Less than 0.2 lb/MBtu
SOx Emissions	Fuel dependent	Fuel dependent, but controllable with sorbent
CO Emissions	0.30 lb/MBtu	0.15 lb/MBtu
* Highly fuel dependent.		

All of the vendors listed have extensive experience supplying commercial combustion systems; each of the vendors has designed and installed more than 50 systems. The technologies offered, the maximum potential for electrical generation, and the commercial status of these vendors is summarized in Table 3-2.

Foster Wheeler, Alstom, and Babcock & Wilcox have the capability to supply stoker boiler systems and fluidized bed boiler systems, including both bubbling fluidized bed (BFB) and circulating fluidized beds (CFB) boilers. These vendors offer stoker technologies with the ability to provide steam for electrical generation facilities up to 50 MW in size and BFB technologies for facilities with capacities approaching 100 MW. While the CFB experience of Babcock & Wilcox is limited to unit sizes of 100 MW, Foster Wheeler and Alstom offer CFBs for facilities up to 300 MW in size. It should be noted that biomass power facilities are often limited in size due to fuel supply constraints and rarely exceed 100 MW of generation capacity.

Kvaerner, Energy Products of Idaho (EPI), and AE&E Von Roll provide fluidized bed systems. Kvaerner has experience with several prominent biomass projects around the world, including the 240 MW Alholmens Kraft facility mentioned above. EPI has designed and installed several biomass fluidized bed combustion units; the company specializes in the combustion of biomass and waste fuels and offers systems capable of providing steam for generation facilities with capacities as large as 40 MW. AE&E Von Roll provides systems on a smaller scale than Kvaerner and EPI, but the company is included in this list due to recent experience providing biomass combustion systems for ethanol facilities in the Midwest.

Table 3-2. Sample List of Direct Combustion (Biomass) Technology Vendors.

Vendor	Technologies Offered	Potential Electrical Generation (MW)	Commercial Status
Foster Wheeler	Stoker	50	Commercial
	BFB/CFB	300	Commercial
Alstom	Stoker	50	Commercial
	BFB/CFB	300	Commercial
Babcock & Wilcox	Stoker	50	Commercial
	BFB/CFB	100	Commercial
Kvaerner	BFB	100	Commercial
Energy Products of Idaho	BFB	40	Commercial
AE&E Von Roll	BFB/CFB	20 [a]	Commercial
Babcock Power	Stoker	55 [b]	Commercial
Detroit Stoker	Stoker	45 [c]	Commercial
McBurney	Stoker	45 [c]	Commercial
Indeck-Keystone	Stoker	73 [d]	Commercial

Notes:

[a] AE&E supplies fluidized bed boilers with maximum steam capacities of 250,000 lb/hr. Black & Veatch estimates that this flow rate would be sufficient to supply a 20 MW generation facility.

[b] Babcock Power supplies stoker boilers with maximum steam capacities of 600,000 lb/hr. Black & Veatch estimates that this flow rate would be sufficient to supply a 55 MW generation facility.

[c] Detroit Stoker and McBurney supply stoker boilers with maximum steam capacities of 500,000 lb/hr. Black & Veatch estimates that this flow rate would be sufficient to supply a 45 MW generation facility.

[d] Indeck-Keystone supplies stoker boilers with maximum steam capacities of 800,000 lb/hr. Black & Veatch estimates that this flow rate would be sufficient to supply a 73 MW generation facility.

Babcock Power, Detroit Stoker, McBurney and Indeck-Keystone supply stoker boiler systems. Each of these vendors is capable of design and installing systems for facilities with generation capacities approaching 50 MW.

All the conventional direct combustion technologies listed above have been commercially available for several years. It is unlikely that these conventional direct fire technologies can readily meet the “advanced biomass power conversion technology” unless these technologies have utilized advanced design features to promote boiler performance and minimize air emissions. Although stoker technology is one of the oldest technologies when compared to others, many new biomass plants have used stoker technologies since modern stokers are typically more efficient (by avoiding the need for auxiliary power for fluidizing the bed) and have lower costs than fluidized bed boilers . Emissions from stoker boilers with back-end controls can be comparable to CFB's, although CO can be an issue (note: in general, for all of the direct combustion technologies, increased moisture content in the biomass feedstock tends to increase CO emissions). Stoker development has been incremental with improvements focused on increasing reliability, availability, and maintenance. In general, water-cooled grates and oscillating/vibrating grate technologies (which have been in existence for over ten years), allows a larger range of fuels to be combusted more efficiently in stoker boilers, with lower emissions. Air-staging can make a stoker operate with a starved-air (gasification) section, followed by combustion. Within the last ten years, for both stoker and fluid bed boilers, there have been some changes/enhancements in the metals used for components and in feedstock metering and feed injection systems, which primarily help reduce down-time and improve boiler availability and overall power plant capacity factors.

It should be noted here that for a facility to qualify for RPS eligibility it should meet both the "advanced biomass power conversion technology" criterion and the "low emission" criterion. As mentioned earlier, while there can be an argument for or against established conventional direct combustion technology improvements meeting the first RPS eligibility criterion, there are some advanced emission and combustion optimization technologies that are being considered to enhance boiler emissions control and to some extent boiler performance. The following sections present some advanced technologies that are being considered for the conventional direct fire combustion units to improve unit performance and emission rates. Most of these technologies are being implemented with the primary goal of reducing emissions of NO_x and in some cases optimizing combustion characteristics.

3.3 Advanced NO_x Control

There are two approaches to achieving a reduction in NO_x emissions; combustion control and post-combustion control. Combustion control methods seek to suppress NO_x formation during the combustion process by controlling the flame temperature and fuel/oxygen ratio. Combustion control methods include low NO_x burners (LNBs), overfire air (OFA) and neural network combustion optimization systems. The post-combustion controls consist of selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) systems, a flue gas treatment that reduces NO_x after its formation. The SNCR and SCR NO_x reduction technologies use either urea or ammonia as a reagent. The SCR technology also uses multiple layers of reduction catalyst. In addition to that, other novel NO_x reduction techniques are also available, as well as other upcoming emerging developmental technologies. The Institute of Clean Air Companies (ICAC) website http://www.icac.com provides lists of suppliers of various technologies described below.

Nitrogen oxide emissions from a new stoker boiler burning biomass waste can vary significantly with the type of biomass being burned, the moisture content of the biomass, temperature on the grate, and quantity of primary air. Although some plants report lower emissions, NO_x emissions from biomass-fired stoker boilers typically range from 0.2 to 0.4 lb/MBtu. Selective non-catalytic reduction (SNCR) systems have been used in stoker boilers to reduce NO_x emissions. In a SNCR system, a reagent (ammonia or urea) is injected into the flue gas to reduce NO_x emissions levels by approximately 50 to 60 percent. Some facilities have reported higher reductions.

3.3.1 Advanced Overfire Air Systems

Conventional OFA systems have been implemented on all kinds of boiler technologies for over ten years. Conventional overfire air (OFA) works by reducing the excess air in the burner zone, thereby enhancing the combustion staging effect and further reducing NO_x emissions. Any residual unburned material, such as carbon monoxide (CO) and unburned carbon, which inevitably escapes the main burner zone, is subsequently oxidized as the OFA is added. The OFA design is typically in the range of 10 to 20 percent of the total combustion air. Thus, the lower furnace is at near stoichiometric conditions. Examples of overfire air system vendors include Babcock & Wilcox, Foster Wheeler, Advanced Combustion Technology, Advanced Burner Technologies, and Mitsui Babcock.

As with primary NO_x control, the performance which can be expected from a given OFA system depends upon a number of factors. As the amount of OFA is increased, the stoichiometry in the burner zone decreases and a point is reached at which CO emissions reach high levels and become uncontrollable. The point at which this occurs can be boiler and fuel type specific, particularly if a fuel is in anyway difficult to burn, and will also depend upon the extent to which it is possible to balance flows between the individual burners, as the OFA amount approaches 10 to 15 percent, the probability for individual burners operating under fuel-rich conditions increases, such that pockets of very high CO emissions and unburned carbon will be formed. Similarly, fuel rich operation at burners close to the water walls can lead to local slag formation and increased tube wastage rates. A fairly high level of unburned material leaving the burner zone can be accommodated by proper overfire port design, where requirements call for rapid and complete mixing of the OFA with the boiler flue gases.

To counteract the problems with conventional OFA, advanced OFA is being increasingly considered and is commercially available on all kinds of boilers firing/co-firing biomass. Advanced OFA utilizes an enhanced design, temperature and direction of OFA and location of the OFA ports to improve the penetration of OFA, enhance the mixing of OFA and flue gas, and ensure that burner velocities are maintained for the Low-NO_x Burners (LNB). Advanced OFA is designed to provide almost complete burnout of the fly and bottom ash carbon content at excess air levels of 3 percent to 5 percent at full load, providing improved combustion efficiencies. A review of published literature on implementation of advanced OFA on stoker boilers suggests that up to 5 percent increase in boiler combustion efficiency can be achieved.

3.3.2 Selective Non-Catalytic Reduction (SNCR)

Selective Non-Catalytic reduction (SNCR) systems reduce NO_x emissions by injecting a reagent at multiple levels in the steam generator as illustrated in Figure 3-1.

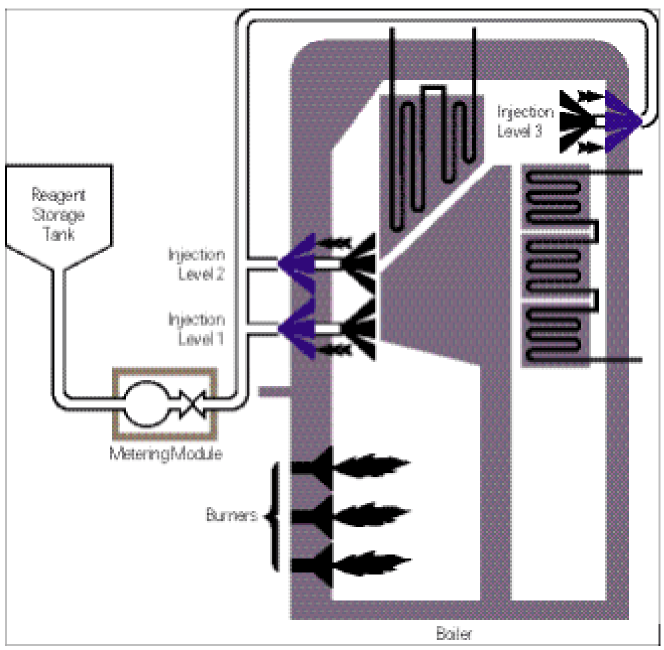

Figure 3-1. Schematic of SNCR System with Multiple Injection Levels.

SNCR systems rely solely on reagent injection rather than a catalyst and an appropriate reagent injection temperature, good reagent/gas mixing, and adequate reaction time to achieve NO_x reductions. SNCR systems can use either ammonia or urea as the reagent. Ammonia or urea is injected into areas of the steam generator where the flue gas temperature ranges from 1,500 to 2,200° F. SNCR technology is more than 10-

years old, however a market place for SNCR has emerged for smaller (usually less than 100 MW) boilers in the past 10-years due to various regulations related to ozone transport, regional haze and BACT.

SNCR systems are capable of achieving a NO_x emission reduction as high as 50 to 60 percent in optimum conditions (adequate reaction time, temperature, and reagent/ flue gas mixing, high baseline NO_x conditions, multiple levels of injectors) with ammonia slips of 10 to 50 ppmvd. Lower ammonia slip values can be achieved with lower NO_x reduction capabilities. Typically, optimum conditions are difficult to achieve, resulting in emission reduction levels of 20 to 40 percent. Potential performance is very site-specific and varies with fuel type, steam generator size, allowable ammonia slip, furnace CO concentrations, and steam generator heat transfer characteristics.

SNCR systems reduce NO_x emissions using the same reduction mechanism as SCR systems. Most of the undesirable chemical reactions occur when reagent is injected at temperatures above or below the optimum range. At best, these undesired reactions consume reagent with no reduction in NO_x emissions while, at worst, the oxidation of ammonia can actually generate NO_x. Accordingly, NO_x reductions and overall reaction stoichiometry are very sensitive to the temperature of the flue gas at the reagent injection point. This complicates the application of SNCR for boilers larger than 100 MW, but this is not an issue for biomass boilers since they are typically no larger than 100 MW.

Reagent injection lances are usually located between the boiler soot blowers in the pendent superheat section. Optimum injector location is mainly a function of temperature and residence time. To accommodate SNCR reaction temperature and boiler turndown requirements, several levels of injection lances are normally installed. Typically, four to five levels of multiple lance nozzles are installed if sufficient boiler height and resident time is available. A flue gas residence time of at least 0.3 second in the optimum temperature range is desired to assure adequate SNCR performance. Residence times in excess of 1 second yield high NO_x reduction levels even under less than ideal mixing conditions. Computational Fluid Dynamics (CFD) and Chemical Kinetic Modeling can be performed to establish the optimum ammonia injection locations and flow patterns. For an existing boiler, minor waterwall modifications are necessary to accommodate installation of SNCR injector lances. Steam piping modifications would probably be required to achieve optimum performance.

3.3.3 Selective Catalytic Reduction (SCR)

Selective Catalytic Reduction (SCR) systems are the most widely used post-combustion NO_x control technology for achieving significant reductions in NO_x

emissions. In SCR systems, vaporized ammonia (NH_3) injected into the flue gas stream acts as a reducing agent when passed over an appropriate amount of catalyst. The NO_x and ammonia reagent react to form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.05 (on a NO_x reduction basis) with very low ammonia slip (unreacted ammonia emissions). A simplified schematic diagram of a typical SCR reactor is illustrated in Figure 3-2. However, most modern SCR systems are built without bypass systems and sonic horns are used in place of steam or air sootblowers. SCR technology has been in place for several years, however, similar to SNCR, the market place for SCRs has exploded in the past few years with various retrofit installations for conventional large coal fired power plants that need to comply with rules that curb ozone transport and regional haze. Biomass boilers can also implement a SCR system for meeting BACT limits under the state permitting programs, or reduce NO_x emissions to less than major source levels to avoid major source construction permitting review.

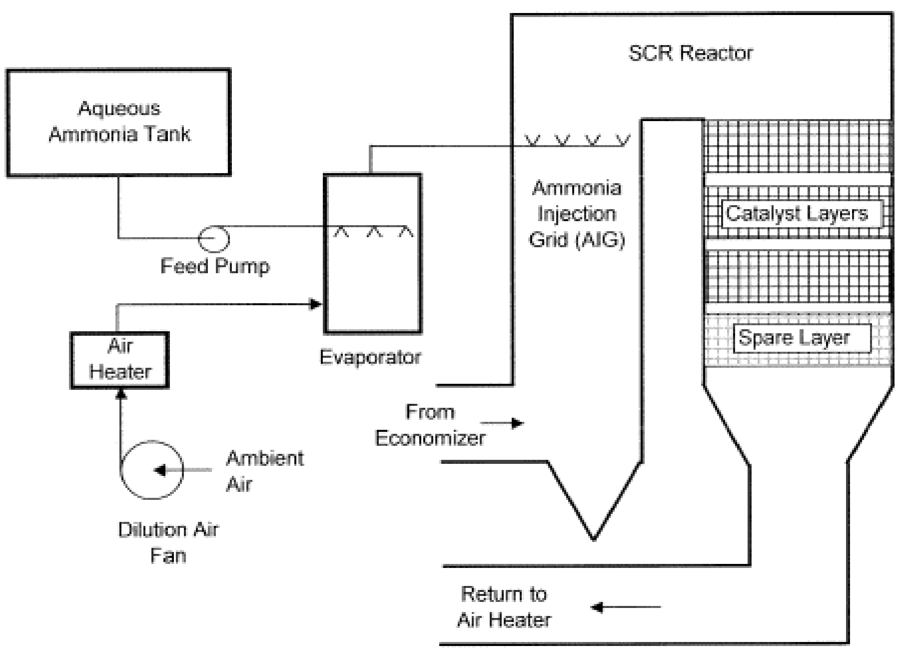

Figure 3-2. Schematic Diagram of a Typical SCR Reactor

The SCR reactor is the housing for the catalyst. The reactor is basically a widened section of ductwork modified by the addition of gas flow distribution devices, catalyst, catalyst support structures, access doors, and sonic horns/soot blowers. An ammonia injection grid is located upstream of the SCR reactor. The SCR reactor is elevated above and upstream of the air heater and downstream of the hot-ESP. By locating the SCR reactor downstream of the hot-ESP, the amount of particulate or dust material flowing through the SCR catalyst is reduced. A lower dust loading reduces catalyst fouling. Therefore, less catalyst volume will be required, minimizing the amount of catalyst and the overall size of the catalyst reactor. The direct effect of this is a lower installed cost for the reactor and lower annual cost for catalyst replacement. Gas flow direction through the reactor is vertically downwards through the layers of catalyst.

The SCR reaction occurs within the temperature range of 550° F to 850° F where the extremes are highly dependent on the fuel quality. The oxidation of SO_2 to SO_3 could also require moderate air heater modifications since the acid dew point temperature of the flue gas is directly related to SO_3 concentration. As the SO_3 concentration increases, the acid dew point of the flue gas increases, potentially increasing corrosion in downstream equipment or possibly requiring an increase in the air heater gas outlet temperature.

The ammonia reagent for the SCR systems can be supplied by anhydrous ammonia, aqueous ammonia, or by conversion of urea to ammonia. Since the ammonia is vaporized prior to contact with the catalyst, the selection of ammonia type does not influence the catalyst performance. However, the selection of ammonia type does affect other subsystem components, including reagent storage, vaporization, injection control, and balance-of-plant requirements. The vast majority of worldwide installations use anhydrous ammonia.

SCR systems have a variety of interfacing system requirements to support operations. These impacts predominately relate to draft, auxiliary power, soot blowing steam, gas temperature, controls, ductwork, reactor footprint, and air heater. The SCR system will impact the boiler draft system. Depending on arrangement and performance requirements, draft losses can range from 4 to 10 in wg. requiring the addition of ID booster fans. If necessary, ductwork and/or boiler box reinforcement may also be required. In conjunction with the fan modification, an expansion of the auxiliary power system might be necessary. Auxiliary power modifications may also be necessary for ammonia supply system requirements.

The major impact of the SCR system can be seen at the air heater where there are two areas of concern. One is the formation and deposition of ammonium bisulfate on the air heater surface. This will cause an increase in the pressure drop of the air heater and degrade its performance and decrease plant efficiency. The other potential danger for the air heater is high concentrations of sulfur trioxide in the flue gas. If the acid dew point temperature has been increased to more than the exhaust temperature, a significant amount of acid gases will condense in the air heater and lead to pluggage and corrosion. Several measures can be taken to avoid or correct this situation. Most important is the right composition of the catalyst to minimize the SO_2 to SO_3 conversion rate.

Catalyst volume is strongly influenced by the NO_x reduction required and the ammonia distribution. The impact of catalyst volume on the design of a hybrid system is on the size of the reactor required to hold the catalyst. If multiple levels of catalyst operating at low flue gas velocity are required, some modifications will be required to the existing ductwork. If widening the ductwork cannot provide adequate catalyst volume, then a separate reactor is required which quickly loses the capital cost advantage of a hybrid system.

Examples of primary vendors that provide SCR systems include Black & Veatch (B&V), Babcock and Wilcox (B&W), Alstom Environmental Inc., Wheelabrator Air Pollution Control (WAPC), and Hitachi Power Systems America.

3.3.4 Regenerative Selective Catalytic Reduction (RSCR™)

RSCR™ are being implemented in the last couple of years on small biomass-fired boilers. According to Babcock Power and that has designed the RSCR system, the first RSCR™ unit was installed on a 16MW wood-fired boiler located in Connecticut in October 2004. A second system was installed on a 50 MW wood fired boiler located in Connecticut in December 2004. Both these installations qualified for the Connecticut Renewable Energy Certificate program.

The RSCR™ system is targeted at tail-end/low temperature applications where the flue gas is relatively cool and clean of particulates and acid gases. This technology combines the heat exchange and thermal efficiency benefits available in a regenerative thermal oxidizer and the principles of NO_x reduction in a SCR, into a single modular unit that is capable of greater than 70 percent NO_x removal and achieving a NO_x emission range of 0.06-0.075 lb/MBtu.[9]

3.3.5 Cascade SCR/SNCR (Hybrid)

The Cascade SCR/SNCR (Hybrid) system uses components and operating characteristics of both SCR and SNCR systems. This system is currently being evaluated for conventional coal fired boilers. It remains to be seen if this system can be implemented for biomass fueled boilers. Hybrid systems were developed to combine the low capital cost and high ammonia slip associated with SNCR systems with the high reduction potential and low ammonia slip inherent to the catalyst of SCR systems. The result is a NO_x reduction alternative that can meet initially low NO_x reduction requirements but upgraded to meet higher reductions at a future date, if required.

[9] From the paper titled *Efficient and Low Emission Stoker Fired Biomass Boiler Technology in Today's Market Place,* by Richard Abrams and Kevin Toupin, PowerGen Renewables Conference 2007.

The SNCR component of the hybrid system is identical to the SNCR system described previously except that the hybrid system may have more levels of multiple lance nozzles for reagent injection. This will increase the capital cost of the SNCR component of the hybrid system. During operation, the SNCR system would be allowed to inject higher amounts of reagent into the flue gas. This increased reagent flow has a two fold effect: NO_x reduction within the boiler is increased while ammonia slip also increases. The ammonia that slips from the SNCR is then used as the reagent for the catalyst.

There are two design philosophies for using this excess ammonia slip. The most conservative hybrid systems will use the catalyst simply as an ammonia slip "scrubber" with some additional NO_x reduction. As with in-duct systems, the flue gas velocity through the catalyst is an important factor in design. Operating in this mode allows maximum NO_x reduction within the boiler by the SNCR while minimizing the catalyst volume requirement. While some NO_x reduction is realized at the catalyst, the relatively small catalyst requirement of this design can potentially fit all the catalyst in a true in-duct arrangement, with no significant ductwork changes, arrangement interference, or structural modifications. The second philosophy uses adequate catalyst volume to obtain significant levels of additional NO_x reduction. The additional reduction is a function of the quantity of ammonia slip, catalyst volume, and distribution of ammonia to NO_x within the flue gas. Using ammonia slip produced by the SNCR system is not a high efficiency method of introducing reagent, due to the low reagent utilization discussed as a part of the SNCR. Therefore, even though the reaction at the catalyst requires 1 ppm of ammonia to remove 1 ppm of NO_x, the SNCR must inject at least 3 ppm of ammonia to generate 1 ppm of ammonia at the catalyst.

3.3.6 Neural Network Systems

Advances in computer hardware and software technology have enabled power generation companies to implement cost-effective optimization solutions that decrease emissions and maximize plant efficiency. This solution commonly referred to as boiler optimization or neural network systems may provide improvements in the heat rate of the boiler and reduce combustion related emissions. Neural network computing differs from traditional computing in that engineering, statistical, and first-law principles have been replaced by complex, time varying, nonlinear relationships. Neural network systems use real-time operational data extracted from a plant Distributed Control System (DCS), "learn" solutions from plant operational experience, and achieve reduction in emissions produced while possibly improving the heat rate of the plant by continuously adapting to changes in plant operation.

Neural network systems also supplement other NO_x reduction strategies. Some of these include LNB, OFA and post-combustion controls such as SCR and SNCR. These systems are also used to help boiler manufacturers tune boilers with poor combustion characteristics or after an LNB retrofit or other boiler modifications such as OFA modifications.

Neuco is a primary vendor that offers neural network systems.

3.4 Summary

Various advanced emission control and combustion optimization technologies offer promise for future biomass power applications that use conventional biomass firing technologies. While there can be an argument for or against established conventional direct combustion technology improvements meeting the first RPS eligibility criterion of "advanced biomass conversion technology", there are some advanced emission and combustion optimization technologies that have become commercially available in the past 10-years. These technologies are being implemented for enhancing boiler emissions control and to some extent boiler performance. Biofuels such as biodiesel are being considered for combustion in conventional internal combustion engines and combustion turbines without significant modifications that can be called "advanced". .