

Hot Gas Conditioning: Recent Progress With Larger-Scale Biomass Gasification Systems

Update and Summary of Recent Progress

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NREL

National Renewable Energy Laboratory

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ABSTRACT

As a result of environmental and policy considerations, there is increasing interest in using renewable biomass resources as feedstock for power, fuels, and chemicals and hydrogen. Biomass gasification is seen as an important technology component for expanding the use of biomass. Advanced biomass gasification systems provide clean products that can be used as fuel or synthesis gases in a variety of environmentally friendly processes.

Advanced end-use technologies such as gas turbines or synthesis gas systems require high quality gases with narrowly defined specifications. Other systems such as boilers may also have fuel quality requirements, but they will be substantially less demanding. The gas product from biomass gasifiers contains quantities of particulates, tars, and other constituents that may exceed these specified limits. As a result, gas cleaning and conditioning will be required in most systems.

Over the past decade, significant research and development activities have been conducted on the topic of gas cleanup and conditioning. This report provides an update of efforts related to large-scale biomass gasification systems and summarizes recent progress. Remaining research and development issues are also summarized.

ACRONYMS AND ABBREVIATIONS

atm	atmospheres
ARBRE	ARable Biomass Renewable Energy project, UK
C	centigrade
CFB	circulating fluidized bed
CHP	combined heat and power
DOE	US Department of Energy
GWh	gigawatt hour
GJ	giga-Joule (10^9 Joule)
ha	hectare
IEA	International Energy Agency
IC	internal combustion (engine)
IGCC	integrated gasification combined cycle
kPa	kiloPascals
kWe	kilowatt of electricity
kWh	kilowatt hour
mg	milligram
MJ	mega Joule (10^6 Joule)
MWe	megawatt of electricity (10^6 Watt)
MWt	megawatt thermal
Nm ³	normal cubic meter
OD	outside diameter
ODT	oven dried ton
PAH	polyaromatic hydrocarbon
ppm	parts per million
ppm	parts per million
R&D	research and development
RD&D	research, development and demonstration
RDF	refuse-derived fuel
sec	second
tpd	tons per day
μm	micrometer

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CONTENTS

ABSTRACT.....	i
ACRONYMS AND ABBREVIATIONS.....	iii
ACKNOWLEDGMENTS.....	v
CONTENTS.....	vii
FIGURES.....	ix
TABLES.....	ix
1. INTRODUCTION.....	1
2. BIOMASS GASIFICATION TECHNOLOGIES.....	3
2.1 Basics of Biomass Gasification.....	3
2.1.1 Gasification Approaches.....	4
2.1.2 Gasifier Designs and Influences on Product Gas Composition.....	4
2.2 Status of Biomass Gasification Technologies.....	7
2.3 The Relationship Between Biomass Gasification and Combustion.....	9
2.4 Gasification of Other Solid Fuels.....	9
3. PRODUCT GAS CLEANUP AND CONDITIONING.....	11
3.1 General Considerations.....	11
3.2 Gas Phase Contaminants.....	12
3.2.1 Particulates.....	12
3.2.2 Alkali Compounds.....	14
3.2.3 Tars from Biomass Gasification.....	16
3.2.4 Nitrogen Containing Contaminants.....	17
3.2.5 Sulfur.....	18
3.2.6 Other Considerations for Synthesis Gas.....	18
3.3 Gas Cleanup Technologies and Recent Progress.....	18
3.3.1 Particulate Removal Technologies.....	19
3.3.2 Technologies for alkali removal.....	23
3.3.3 Tar Removal Technologies.....	24
3.3.4 Removal of Nitrogen Containing Compounds.....	32
3.3.5 Sulfur Removal.....	32
3.3.6 Hydrocarbon reduction and gas conditioning for producing synthesis gases and hydrogen.....	33
3.4 Survey of Biomass Gas Conditioning Technologies.....	34
4. INTEGRATED GASIFICATION/END-USE SYSTEMS.....	35
4.1 Fuel Gases for Systems With Minimal Gas Conditioning Requirements.....	37
4.1.1 Overall Gas Conditioning Strategy - Minimal Gas Conditioning.....	37
4.1.2 Example of a Gasification System Requiring Minimal Gas Conditioning: Lahti , Finland.....	37

4.1.3	Example of a Gasification System Requiring Minimal Gas Conditioning: Primenergy, Stuttgart Arkansas	40
4.2	Cool Fuel Gases for Systems With Significant Gas Conditioning Requirements.....	42
4.2.1	Overall Gas Conditioning Strategy - Producing Clean, Cool Fuel Gases.....	43
4.2.2	Example of a Gasification System Producing Cool, Conditioned Gas: Amergas Facility in Geertruidenberg, Netherlands	44
4.2.3	Example of a Gasification Systems Producing Cool, Conditioned Gas: ARBRE Facility in United Kingdom	47
4.2.4	Example of a Gasification Systems Producing Cool, Conditioned Gas: Vermont Gasifier Project , Burlington, Vermont, USA	50
4.2.5	Other Related Systems.....	53
4.3	Hot or Warm Fuel Gases for Systems With Significant Gas Conditioning Requirements	53
4.3.1	Example of a Gasification System Producing Hot, Conditioned Gas: Värnamo Facility in Sweden	54
4.4	Synthesis Gases for the Production of Fuels and Chemicals, and Hydrogen for Use With Fuel Cells	57
4.4.1	Current Production of Fuels and Chemicals from Synthesis Gas	58
4.4.2	Biomass-based Production of Synthesis Gas	58
4.4.3	Biomass Gasification to Produce Hydrogen for Fuel Cells	60
5.	DISCUSSION AND RESEARCH NEEDS	63
5.1	Summary of the Status of Gas Conditioning for Large-Scale Gasification Systems	63
5.1.1	Progress in Understanding Gas Conditioning Processes	63
5.1.2	Progress Relating to Gas Conditioning in Integrated Systems	65
5.2	Summary of Research and Development Needs	68
6.	REFERENCES	71
APPENDIX 1.	GAS CONDITIONING TECHNOLOGY SURVEY.....	81

FIGURES

Figure 4.1.	Temperature Profile of Lahti Gasification System.....	38
Figure 4.2.	Temperature Profile of Primenergy Gasification System	41
Figure 4.3.	Temperature Profile of Amergas Gasification System.....	45
Figure 4.4	Temperature Profile of ARBRE Gasification System.....	48
Figure 4.5	Temperature Profile of Planned Vermont Gasification System.....	51
Figure 4.6.	Temperature Profile of the Värnamo Gasifier System	55

TABLES

Table 2.1.	Comparison of measured particulate and tar levels from different biomass gasifier designs..	5
Table 3.1.	Inorganic content of biomass feedstocks.....	14
Table 3.2.	Composition of ash from selected biomass.....	14
Table 3.3.	Concentration of alkali in fuel.....	15
Table 3.4.	Alkali filtration results.	24
Table 3.5.	Relative efficiencies of tar removal for wet scrubbers.....	26
Table 3.6.	Reported tar removal efficiencies of wet scrubbers	26
Table 4.1.	Representative large-scale gasification projects	36
Table 4.2.	Gas conditioning systems requiring minimal gas conditioning. Example: Lahti gasifier where product gas is cofired with coal in a steam-cycle power station. ...	40
Table 4.3.	Gas conditioning systems requiring minimal gas conditioning. Example: Primenergy gasifier where product gas is used for steam-cycle power generation.	42
Table 4.4.	Gas conditioning in systems requiring significant gas conditioning. Example: Amergas facility in Netherlands	46
Table 4.5.	Particulate loading limits for gas turbines.	48
Table 4.6.	Gas conditioning in systems requiring significant gas conditioning. Example: ARBRE facility in United Kingdom. Gasification/ gas turbine cogeneration facility.	49
Table 4.7.	Gas conditioning in systems requiring significant gas conditioning. Example: Vermont Gasifier Project. Gasification/ gas turbine cogeneration facility.	52
Table 4.8.	Gas conditioning in systems requiring significant gas conditioning. Example: Värnamo facility in Sweden. Gasification/ gas turbine cogeneration facility.....	56
Table 4.9.	General fuel cell characteristics.....	62

1. INTRODUCTION

As a result of environmental and other policy considerations, there is increasing world-wide interest in the use of biomass resources as feedstocks for producing power, fuels, and chemicals. Biomass resources are a major component of strategies to mitigate global climate change. Plant growth “recycles” CO₂ from the atmosphere, and the use of biomass resources for energy and chemicals results in low net emissions of carbon dioxide. The emissions of NO_x and SO_x from biomass facilities are also typically low. This helps biomass technologies meet local and regional environmental regulations and reduce emissions that contribute to acid rain. The use of these locally produced energy resources also results in new markets for agricultural and forestry products and provides a mechanism for rural economic development. Because of these and other factors, many national governments are currently developing policies and regulations intended to expand the use of biomass over the next decade and beyond.

Biomass gasification technologies are expected to be an important part of the effort to meet these goals of expanding the use of biomass. Gasification technologies provide the opportunity to convert renewable biomass feedstocks into clean fuel gases or synthesis gases. These gaseous products can be burned to generate heat or electricity, or they can potentially be used in the synthesis of liquid transportation fuels, hydrogen, or chemicals. Gasification offers a combination of flexibility, efficiency, and environmental acceptability that is essential in meeting future energy requirements.

Historically, development of biomass gasifiers has focused on small-scale units for a variety of uses. The interest in small-scale gasifiers began over a century ago and has continued into the present. Over the past two decades, there has been increasing interest in larger-scale biomass gasifiers that can reliably be used to commercially produce heat, power, or other products.

As a result of the interest in large-scale systems, governments and industries have conducted extensive research, development, and demonstration (RD&D) activities over the past two decades. The goal of this work has been to develop efficient, cost-effective commercial gasification systems suitable for large-scale applications. “Large-scale” is defined as including gasifiers capable of utilizing several tons of biomass per day with thermal outputs of 10-20 MW_t or higher. These gasifiers would typically provide fuel for commercial power generation, a source of heat and/or power to meet major industrial needs, or gases for production of fuels and chemicals.

The development of gasification systems has also included extensive research on product gas cleanup. The importance of producing a high-quality product has been appreciated for many years, at least on a conceptual basis. Raw product gases may contain particulates, tars, ammonia, and other impurities that can interfere with downstream processes and components or create emissions problems. For low-technology applications where the product gas is simply burned to provide heat, such as a cement kiln, the gas clean-up requirements may be minimal. However, high technology systems such as gas turbines or systems using synthesis gases require much cleaner fuel gases. Extensive clean-up of the raw gasifier product may also be required to meet environmental regulations, even when the product is used even in relatively undemanding applications. The critical need to match fuel quality with end-use requirements was strongly reinforced by several project failures,

particularly those in the late 1980's and early 1990's where low-quality biomass gases damaged internal combustion and turbine engines.

In 1993, the International Energy Agency (IEA) Bioenergy Gasification Activity prepared a document summarizing the status of gas clean-up systems at that time (Graham and Bain, 1993). This document identified primary gas contaminants, discussed unit operations that could potentially remove such contaminants, and discussed gas-cleaning strategies in relation to the end-use of the product gas. Since then, progress has been made in developing a better understanding of the chemistry and mechanisms of hot gas cleanup and conditioning, and recent gasification systems have incorporated technologies to improve gas cleanup.

In this report, we provide an update of the status of biomass hot-gas cleanup and related gas cleanup issues in these larger-scale systems. Emphasis is placed on events over the past 5-7 years to highlight progress since the original report was completed. This report contains:

- a summary of recent progress in biomass gasification
- an overview of the characterization of raw product from biomass gasifiers
- an overview of the methodologies and technologies for gas cleanup, including comparative work with coal gasification
- examples of large-scale gasification/gas cleanup systems
- discussion of remaining research and development needs

2. BIOMASS GASIFICATION TECHNOLOGIES

Biomass gasification offers several potential advantages over alternative approaches. First, conversion of the solid feedstock to a gaseous fuel significantly increases the opportunities for using biomass as an energy source. Since the gasification product is a fuel or synthesis gas rather than simply a stream of hot combustion products, the fuel can be used for different purposes. When sufficiently cleaned, the product gas can be used for applications such as:

- Powering higher-efficiency (~40%) conversion devices such as gas turbines
- Retrofitting existing oil- or natural gas-fired equipment to operate on biomass
- Providing fuel for fuel cells or other distributed generation technologies
- Synthesizing liquid fuels, or chemicals

Gasification also offers potential environmental advantages when compared to combustion systems. The fuel gas produced by gasifiers is lower in both volume and temperature than the fully combusted product from a combustor. These characteristics provide an opportunity to clean and condition the fuel gas prior to use. Combustion of the resulting gaseous fuel can be more accurately controlled than combustion of the solid biomass. As a result, the overall emissions from gasification-based power systems, particularly those of NO_x , can be reduced. The ability to produce clean energy potentially allows gasification to be used in other situations where combustion is unsuitable including:

- Facilities where stringent emission standards are enforced
- Locations where public perception of combustors is negative

These combined advantages of flexibility and environmental compatibility make gasification a significant option for new, high-efficiency electricity generation applications and for the synthesis of liquid fuels from biomass.

Biomass gasification has been a subject of interest for many decades. Historically, emphasis has been placed on small-scale gasifiers, and numerous designs have been built and tested. The products from these gasifiers have been used in a variety of applications ranging from fuel for emergency vehicles during World War II to fuel for stationary heat and power generation today (National Research Council, 1983; Reed and Das, 1998; Klass, 1998; Quaak, et al, 1999; IEA Bioenergy, 1997; Barker, 1998; Costello and Chum, 1998; Stevens, 1999; BTG, 2000). Over the past two decades, there has been increasing interest in the use of larger-scale gasifiers to provide fuels for advanced power generation concepts such as gas turbines, or for use where strict environmental emission regulations exist. In these cases, the raw product gas must be cleaned and conditioned prior to use.

The characteristics of the raw product gas are highly dependent on the type of gasification process used and the design of the gasifier. The basics of gasification and their implications with respect to gas quality are discussed below.

2.1 Basics of Biomass Gasification

At temperatures of approximately 600-1000 °C, solid biomass undergoes thermal decomposition to form gas-phase products that typically include carbon monoxide, hydrogen, methane, carbon dioxide, and water. In most cases, solid char plus tars that

would be liquids under ambient conditions are also formed. The product distribution and gas composition depends on many factors including the gasification temperature and the reactor type. The kinetics and mechanisms of biomass gasification have been studied extensively, and more extensive reviews of gasification can be found elsewhere (Karlschmitt and Bridgwater, 1997; Klass, 1998; Quaak, et al, 1998).

As a result of many years of effort, numerous gasifiers have been designed and tested, mostly at small scale with capacities ranging from a few kilograms to a few tons of biomass feedstock per day. The selection of a particular design has a major influence on the primary characteristics of the product gas including its energy content, the concentrations of tars and particulates in the gas, and the relative amounts of various gaseous products such as hydrogen, carbon monoxide, and carbon dioxide.

2.1.1 Gasification Approaches

While the characteristics of the product gases from different concepts varies significantly, gasification approaches can be grouped into two general types based on the energy content of the product. The energy content of the gas depends on the approach used to supply heat to drive the gasification reactions. Most designs use oxygen, either in air or in its separated form, as an oxidizing agent to generate heat by partially combusting the biomass feedstock. When heat is supplied by partial oxidation with air (air-blown gasification), nitrogen in the air dilutes the product. The resulting gas is classified as a low-energy gas and has a heating value of approximately 2.5-8.0 MJ/Nm³. Low-energy gasifiers are best used in situations where the heat content of the gas is not a critical issue such as cofiring applications, district heating systems, and many electric generation systems.

Medium-energy gases can be produced using pure oxygen instead of air as the oxidizing agent to provide heat for the gasification. The use of separated oxygen eliminates the nitrogen diluent, and a medium-energy gas (10-20 MJ/Nm³) can be produced. In the absence of oxygen, medium-energy gases can also be produced by pyrolytic gasification by using a reactor where heat for the gasification is provided from an external source (indirectly-fired gasification). In these gasifiers, heat is provided using methods such as heat exchangers and circulating the hot bed material. Medium-energy gasifiers are appropriate for situations where a higher energy-content gas is desired. The synthesis of liquid fuels requires the use of medium-energy gasifiers since these systems cannot effectively deal with the dilution of the product by nitrogen that occurs in air-blown systems.

2.1.2 Gasifier Designs and Influences on Product Gas Composition

Low- and medium-energy gasifiers have been built and operated using a wide variety of configurations including:

- Updraft or downdraft fixed beds
- Moving “fluidized” beds where fluidized or entrained solids serve as the bed material
- Others including moving grate beds and molten salt reactors

Most of these configurations can be designed for operation at either ambient conditions or pressurized conditions up to approximately 20 atm. The maximum scale of operation of the

gasifier is also influenced by its configuration, as discussed below. Gasifier configurations are also discussed briefly below, and more detailed information is available elsewhere (Klass, 1998; Quaak, et al, 1998; IEA Bioenergy, 1997; Karlschmitt and Bridgwater, 1997; CEETA, 1995; Stassen, 1995).

For either low- or medium-energy gasifiers, selection of a particular reactor design will directly influence the characteristics of the raw product gas including its temperature and the amounts of tars and particulates present. As a result, it is essential to carefully select gasifier designs that will match product characteristics with end-uses. To date, most gasifiers have been designed with either fixed bed or “fluidized” bed technologies, although a variety of other designs have been proposed and tested. The influences of various gasifier types on the product composition are summarized below and have been discussed in more detail elsewhere. Representative levels of tars and particulates for generic types of gasifiers are summarized in Table 2.1.

Table 2.1. Comparison of measured particulate and tar levels from different biomass gasifier designs. (Source: Graham and Bain, 1993; Neeft, et al, 1999).

Gasifier Type	Particulate Loading (g/Nm ³)			Tar Loading (g/Nm ³)		
	Low	High	Representative Range	Min.	Max.	Representative Range
Fixed Bed						
Downdraft	0.01	10	0.1 - 0.2	0.04	6.0	0.1 - 1.2
Updraft	0.1	3	0.1 - 1.0	1	150	20 - 100
Moving Bed						
Fluidized Bed	1	100	2 - 20	<0.1	23	1 - 15
Circulating Fluidized Bed	8	100	10-35	<1	30	1 - 15

Note: The representative range is presented as a qualitative comparison of emissions from different gasifier types. Measurements are from selected facilities and may not be representative of all gasifiers in a particular class. Actual emissions from any specific gasifier depend on many factors and must be measured under steady-state operating conditions.

2.1.2.1 Fixed Bed Gasifiers

Fixed bed gasifiers have a stationary reaction zone typically supported by a grate. They are usually fed from the top of the reactor and can be designed in either downdraft or updraft configurations. The product gases from these two gasifier configurations vary significantly. Fixed-bed gasifiers are relatively easy to design and operate and they are best suited to small- to medium-scale applications with thermal requirements up to a few MW_t. At larger scale, fixed bed gasifiers can encounter problems with bridging of the biomass feedstock. This leads to uneven gas flow. Achieving uniform temperatures throughout the gasifier at large scale can also be difficult due to the absence of mixing in the reaction zone. Most fixed-bed gasifiers are air-blown and produce low-energy gases, although oxygen-blown designs have been tested.

With *fixed-bed downdraft gasifiers*, air or oxygen passes downward through the gasifier, co-current to solids flow. Gasification occurs near the bottom of the gasifier in a relatively shallow hot reaction zone composed of a layer of charcoal. The oxidation of the biomass generates heat to sustain the gasification process. Most tars in the product gas are destroyed by thermal cracking as they pass through the hot reaction zone and the raw product then

exits the gasifier at high temperature. The particulate levels in the product gas are typically low due to the absence of turbulence in the gasifier, but the gas may contain alkali vapors as it exits the hot reaction zone.

With *fixed-bed updraft gasifiers*, the air or oxygen passes upward through a hot reactive zone near the bottom of the gasifier in a direction counter-current to the flow of solid material. Exothermic reactions between air/oxygen and the charcoal in the bed drive the gasification process. Heat in the raw gas is transferred to the biomass feedstock as the hot gases pass upward, and biomass descending through the gasifier sequentially undergoes drying, pyrolysis, and finally gasification. The product gas exits at a relatively low temperature. Tar concentrations in the product gas are high since the tar vapors formed by pyrolysis reactions are swept upward through the reactor with the product gas. Particulate levels in the raw product gas are typically low because of the non-turbulent conditions. In addition, ash is swept along with the solids in the opposite direction of the gas flow and is eventually withdrawn from the bottom of the gasifier. Most smaller-scale gasifiers are based on fixed-bed designs.

2.1.2.2 “Fluidized” bed gasifiers

Fluidized bed gasifiers are defined here as those with a moving bed of inert material such as sand. Examples include bubbling fluidized bed gasifiers where the bed material is agitated by gases flowing through it, circulating fluidized bed (CFB) gasifiers where the bed material circulates between the gasifier and a secondary vessel, and entrained bed gasifiers where the solids are entrained in the gas flow at higher velocities. The gas used to fluidize or entrain the bed material can be air, oxygen, steam, recycled product gas, or a combination. Depending on design, biomass can be fed into the top, bottom, or middle of the moving bed.

Heat to drive the gasification reaction can be provided in a variety of ways in fluidized bed gasifiers. Direct heating occurs when air or oxygen in fluidizing gas partially oxidizes the biomass and heat is released by the exothermic reactions that occur. Indirect heating methods such as internal heat exchangers, using preheated bed material, or other means can also be used to drive the gasification reactions. The turbulence in the bed promotes effective mixing and efficient heat transfer. The raw product gas typically exits the reactor at relatively high temperatures. Fluidized bed gasifiers can be effectively sized for medium- to large-scale facilities and are best suited to situations where there is a relatively constant demand for the gas product. Essentially, all of the larger-scale gasifier facilities built and tested in the last decade use fluidized bed designs.

The product gas exiting from the gasifier typically has high levels of particulates as a result of the turbulence in the reactor. The particulate matter consists both of ash originating from the biomass and fine particles of attrited bed material. Cyclone filters are usually an integral part of the system and are used as a method to remove the bed material from the gas stream. Since the gas is typically hot, it may also contain vaporized alkali salts, as will be discussed in more detail later. The amount of tars in the raw gas can vary significantly depending on the specific reactor design, as shown in Table 2.1. Typical moving bed gasifiers produce lower concentrations of tar than fixed bed updraft types, but more than fixed bed downdraft reactors. Depending on the reactor design, the composition of the tars can range from partially cracked pyrolysis products to highly refractory polyaromatic hydrocarbons.

Other gasifiers: Historically, most biomass gasifiers have been based on the fixed and moving bed designs described above. However, many other design configurations have been proposed, designed, and tested. For example, moving grate gasifiers similar to some combustors and incinerators have been tested, as have others derived from fixed bed downdraft designs. In the latter, the lower fixed grate is replaced by a moving or rotating grate or platform. Many other designs such as molten salt gasifiers and supercritical fluid gasifiers have also been examined, but these designs have not been tested at a larger scale. In these concepts, the temperature of the product gas and its composition will vary depending on the type of design chosen, but those characteristics generally fall within the limits of the fixed and moving bed designs described above. Because the performance of these designs is more reactor-specific and less generic, they are not addressed in detail here. More complete reviews of biomass gasification history and design are available elsewhere (Reed, 1999, Stassen, 1995).

2.2 Status of Biomass Gasification Technologies

As indicated, biomass gasification technologies have been a subject of commercial interest for several decades. Interest in biomass gasification increased substantially during the 1970s due to uncertainties over petroleum supplies. The concept that gasification could provide secure source of energy from locally produced biomass feedstocks attracted many technology developers and entrepreneurs. Through the mid-1980s, small-scale gasification remained in a near-commercial stage of development. While gasifiers were available from commercial vendors, the products from that period were often unreliable and ineffective. Since the mid 1980s, improvements in the technology and better selection of opportunities have led to improved commercial success. At present, there are several dozen smaller-scale biomass gasifiers in active service world-wide (Reed, 1999, BTG, 2000) that provide fuel for heat and power needs. These gasifiers are available from vendors with proven technologies and use a variety of feedstocks including wood, agricultural residues, AND, animal wastes.

For about two decades, there has also been increasing interest in large-scale biomass gasification. Throughout the 1980s, governments and private industries sponsored research and development efforts on biomass gasification with the goal of developing viable, large-scale gasifiers. The research efforts have helped to create a better understanding of reaction fundamentals, and the development work has resulted in the construction and testing of several demonstration-scale facilities. The sizes of these demonstration facilities varied, but they typically could process 5 - 20 tons of biomass per day. The facilities were intended to resolve remaining technical questions at a reasonable scale of operation and to provide the basis for the introduction of large scale, commercial gasifiers. A summary of biomass gasification research sponsored by the U.S. Department of Energy (DOE) is available (US DOE 1996a; Stevens, 1994), and information on international gasification activities has been compiled (IEA Bioenergy, 1997, NOVEM, 1999). Recent surveys of biomass gasifiers are also available (Reed, 1999; BTG Group, 2000).

By the early 1990s there was widespread interest in larger-scale gasifier systems for power generation. One area of interest focused on the use of gas turbines to replace steam-based systems. The high efficiency of turbine systems presented opportunities that encouraged investments from both governments and private industry. By the mid-1990s, a second area of interest had emerged relating to the use of large-scale gasifiers to provide fuel gas from biomass which could be co-fired in conventional steam-based coal generating facilities.

As the development has proceeded, it has been widely recognized that raw product from large-scale gasifiers will require cleaning and conditioning to be compatible with end-uses such as gas turbines. The large-scale systems almost exclusively use fluidized bed gasifiers that produce raw gases with particulate and tar levels unsuitable for demanding applications unless the gases are cleaned. Several demonstration systems were planned that would complete gasifier development and test the compatibility of gas turbines with the cleaned fuel. The concepts ranged in size from a few hundred kW_e to approximately 75 MW_e in electric generation capability. Several of the projects were planned using a step approach where the gasifier was to be built and tested first, and the gas turbine was to be added at a later date. These projects also included extensive planning and efforts to ensure the raw gasifier product gas could be cleaned sufficiently to meet the gas turbine requirements. These projects are described in more detail elsewhere (Stevens, 1999).

By the late 1990s, several larger-scale biomass gasification facilities with thermal outputs up to about 85 MW_t had been built or were in the planning or demonstration stage. These include gasifiers that provided biomass-derived fuel gases to be co-fired with coal and those that provided fuels for generating electricity using advanced gas turbine systems. Selected gasifier developments are discussed in more detail in Section 4 of this report.

At the beginning of 2000, additional interest has been expressed in the use of biomass gasification as a method to produce synthesis gases and hydrogen. Synthesis gases would be used for producing transportation fuels or chemicals. Interest in biomass-derived hydrogen has been primarily in the area of providing a clean fuel for fuel cell operation. Fuel cells provide the potential for efficient power generation and are compatible with distributed energy generation.

As a result of the interest in large-scale biomass gasification systems, progress has been made on both the gasification step and on gas cleanup issues over the past decade. For the gasification step, the main progress has been in relation to the scale-up of biomass gasifiers. Work over this period has shown both the potential of these systems and the difficulties of starting first-of-a-kind facilities. Gasifier scale-up projects have consistently experienced operational difficulties and delays typical of large projects using "new" technologies. Problems with components such as feeders are being solved as they arise, and the operability of the larger-scale gasifiers is improving. While the problems that have been encountered appear to be solvable, the overall scale-up of biomass gasifiers has proceeded more slowly than predicted by the optimistic estimates of the early 1990s. Despite these difficulties, several gasifiers at a variety of scales are currently in full commercial operation. The successful gasifiers provide fuel gases for applications that can tolerate significant levels of particulates and tars in the gas. An example is the gasifier located in Lahti, Finland where the fuel gas is co-fired in a coal combustor (Foster Wheeler, 1999). This system is discussed in more detail in Section 4.

Gasifier systems capable of producing very clean fuel gases for demanding applications remain at the demonstration and near-commercial stage of development. Significant progress has been made in developing a better understanding of gas cleanup issues and in demonstrating technologies that can solve those problems. In Section 3 of this report, progress to clean gases for highly demanding technologies such as gas turbines is summarized. This work includes the removal of tars, particulates, and alkali from the gas stream as well as control of nitrogen oxide emissions. In Section 4 of this report, integrated gasification/gas cleanup systems are discussed.

2.3 The Relationship Between Biomass Gasification and Combustion

While biomass gasification offers significant potential, it should be noted that a vast majority (> 98%) of all energy from biomass is currently produced using combustion systems. These systems provide heat for a variety of needs including power generation, industrial processing, space heating, etc. In conventional combustion-based electric power systems, biomass is burned, the heat is used to generate steam, and the steam is then used to drive a steam turbine. The electric generation efficiency of these systems ranges from about 20% in older systems to over 30% in newer ones. In many cases, heat is recovered for heating or industrial processing needs to improve the overall thermal efficiency of the system. Combined heat and power (CHP) systems such as district heating systems are well established in Europe and are used by North American industries.

Biomass combustion technologies are technologically mature and are readily available from commercial vendors. Since they offer reliable operation with proven results, combustion systems are likely to continue to be an important option for biomass power in the foreseeable future. Combustion systems will likely continue to compete effectively in situations where conventional steam-cycle power generation is economically feasible.

2.4 Gasification of Other Solid Fuels

The gasification of other solid fuels, particularly coal, has also been of interest for more than a century. Like biomass gasification processes, conversion of these solid energy feedstocks to gaseous fuels provides greater flexibility for their use and can reduce unwanted environmental emissions.

Coal has both higher bulk and energy densities than biomass. These factors allow coal to be economically transported longer distances, which in turn allows coal facilities to be significantly larger than those fueled by biomass. By comparison, large-scale biomass gasification facilities will probably have capacities of less than 100 MW_e, while present coal gasification power systems in commercial operation have capacities exceeding 250 MW_e (U.S. Department of Energy 1996b; 1996c). The coal facilities include power generation systems using high efficiency gas turbines. Larger coal-based facilities are also feasible. Coal gasification has also been used over many years to produce synthesis gases for fuels and chemicals synthesis in several locations including South Africa.

At present, the motivational forces driving development of biomass gasification are different than those for coal. Interest in biomass gasification is being driven at least in part by international concern about carbon dioxide emissions. Since biomass can be grown at about the same rate it is consumed, this feedstock can provide renewable sources of power and fuels with low levels of net CO₂ emissions. Biomass gasification can therefore potentially help companies and governments meet CO₂ reduction requirements in appropriately sized power facilities.

Coal gasification, by comparison, is of interest in areas where there is abundant coal and where alternate resources, particularly natural gas, are in limited supply. In those areas, large-scale coal-gasification facilities can have economic potential. Currently, international interest in reducing global CO₂ emissions coupled with low natural gas prices have made coal a less appealing choice than natural gas. Future interest in coal-based technologies is

more difficult to predict. Concerns about CO₂ emissions are expected to increase, but natural gas prices have also climbed significantly. The relative influence of these factors on the future growth of coal-based power generation is unknown.

Because of the differences in the characteristics and reaction behavior of biomass and coal, the technologies to gasify them and clean the raw product gases will be different. Coal typically has a higher ash and sulfur content than biomass, which requires additional processing steps to achieve a high quality fuel gas (Newby, 1993). The temperature and tar content of the raw product will also be different in biomass and coal systems. In dealing with the two feedstocks, it is important to recognize the differences and appropriately exploit the feedstock characteristics in both systems. The discussions of biomass hot gas cleanup in the following sections of this report include references to coal-based technologies where commonalities exist.

3. PRODUCT GAS CLEANUP AND CONDITIONING

3.1 General Considerations

The raw product gas exiting a biomass gasifier contains particulates, tars, and other constituents that may interfere with downstream utilization technologies. The concentrations of these constituents will depend on the reactor design and other factors as explained previously. Regardless of the scale of the gasifier, its design configuration, or the biomass feedstock, the characteristics of the product gas must match the requirements of the intended use. For some applications such as kilns or co-firing systems, the raw fuel gas may be used with little or no cleanup. In other applications, such as gas turbines or internal combustion engines, extensive gas cleanup may be needed to meet stringent fuel quality requirements. If the gas is to be used for synthesis of liquid fuels, the product must not only be clean but must also have specified molecular ratios of components such as H₂ or CO. In all cases, care must be exercised to ensure the product gas is compatible with the end-use.

The consequences of inadequate gas cleaning have been amply demonstrated with biomass gasification systems. Beginning in the 1970s and continuing into the 1990s, several research and development groups attempted to commercialize small-scale gasifier/internal combustion (IC) piston engine systems for electricity and mechanical power generation*. Commercial projects and demonstrations were started in locations including the Americas, Europe, and Asia. While IC engines can effectively use clean fuel gases from biomass, some of these early systems did not provide for adequate tar removal from the product gas. The IC engines operated reasonably well for a short period of time but then failed within few hundred hours to difficulties such as tar accumulation in valves. This inability to match the gasifier product with the desired end-use contributed to a poor public perception of the reliability of biomass gasifiers.

Since the mid-1980s, significant research efforts have been directed toward the development of methods to clean the raw products from biomass gasifiers. Much of this effort was related to the potential use of large-scale gasifiers coupled with high-efficiency gas turbine generating systems. In the mid-and late-1990s, several large-scale gasifier/gas turbine projects were proposed, and a few of these are in the advanced construction and early stages of operation. These end-use technologies to achieve high electrical conversion efficiencies have stringent requirements regarding gas quality.

Research on gas cleanup and conditioning has also been motivated by the need to meet environmental emissions limits in urban areas, such as when urban wood wastes are used as feedstocks. Large-scale systems to provide a biomass-derived fuel gas for cofiring in coal-burning facilities have also been constructed and are entering commercial operation. The cofiring units provide fuel for steam-cycle power generation and must meet local environmental regulations.

In addition, the use of biomass gasification to produce fuels such as Fischer-Tropsch liquids has also received renewed attention. Systems for producing these fuels must address the

* Small gasifiers were also used in some areas of Europe during World War II to provide emergency fuels for vehicles (National Research Council, 1983). Engine operability problems were encountered, but the need for emergency sources of fuel to harvest food and provide for key transport needs overrode those considerations.

same gas quality issues as high efficiency turbine systems including removal of tars and particulates. These systems also require the catalytic reforming of product gas to produce a synthesis-quality product with specific compositions and specific molecular ratios of hydrogen and carbon monoxide gases. The catalysts in these systems and the requirements for narrowly defined synthesis gas compositions impose additional requirements on the product gas quality as compared to electricity generation systems. For nearly twenty years, the low costs of petroleum have made the option of liquid fuels from biomass economically unattractive. Recently, however, the rapid increases in petroleum prices have generated renewed interest in liquid fuels from biomass via thermochemical gasification routes.

Recent interest has also been expressed in the use of biomass gasification to produce hydrogen for use in fuel cells. Production of clean, hydrogen-rich fuel gases will require similar or perhaps even more demanding gas conditioning including particulate and tar removal in addition to removal of unwanted light hydrocarbons, carbon monoxide, and others.

As a result of these and other developments, the topic of gas cleanup has received substantial attention, both in terms of basic research and of technology development related to commercial gasifier demonstrations. Much of this interest has been focused on larger-scale systems capable of commercial power production in highly developed countries.

3.2. Gas Phase Contaminants

While it is desirable to select and design gasifiers that reduce contaminants at the source, the nature of biomass thermal gasification requires additional gas cleanup in most cases. Gas cleanup systems may contain several components such as cyclones, scrubbers, or filters; each of which removes one or more contaminants. Systems producing either fuel or synthesis gas must deal with the cleanup of five primary contaminants including:

- particulates
- alkali compounds
- tars
- nitrogen-containing components
- sulfur

These contaminants and the technologies for treating them are discussed in more detail below. In addition, synthesis gas systems must address the presence of low molecular weight hydrocarbons such as methane or ethane. These hydrocarbons are beneficial to fuel gases since they tend to increase the heating value of the product. However, they are undesirable in synthesis gases where they are unreactive and reduce overall conversion efficiencies to the desired product. Excess hydrocarbons may also deactivate catalysts in the system. In addition, the ratios of various molecular components in the synthesis gas must be adjusted. The issues dealing with synthesis gases are discussed later in this report.

3.2.1 Particulates

Particulates are defined here as solid-phase materials entrained in the raw product gas stream as it exits the gasifier. Particulates typically include the inorganic “ash” derived from mineral matter in the biomass feedstock, unconverted biomass in the form of char, or

material from the gasifier bed. Most large-scale gasifiers use bubbling or circulating fluidized configurations to ensure uniform bed conditions during gasification. The turbulent conditions in these gasifiers produce high particulate loadings in the product gases. As a result, particulate cleanup will typically be necessary with these systems.

Turbulent-flow fluidized bed systems necessarily include cyclones to separate the bed material from the product gases. The cyclone serves as the initial particulate removal technology and removes the bulk of coarse particulates, but finer fly ash will remain in the gas stream. The resulting fly ash consists of smaller-diameter material that can create operational and visual emissions problems if not removed.

A primary source of fly ash particulates is the mineral matter in the biomass feedstock. As the feedstock is gasified, the inorganic matter from the feedstock may be either retained in the gasifier bed or entrained in the product gas and swept from the reactor. The concentrations of ash in the product gas are therefore dependent both on reactor design and on the mineral content of the biomass feedstock.

The total concentrations of inorganic material in selected biomass feedstocks are shown in Table 3.1. Total mineral concentrations in clean wood are typically 1-2%, and herbaceous crops contain approximately 10%. Crop residues such as straw or rice hulls typically contain 15-20% inorganic material. Mineral matter from other sources may also contribute to ash in the product gas. For example, silica from soil that is mixed with the biomass during its handling and preparation may be present. In gasification systems with moving beds, inorganic particulates may include fine material from the attrition of the bed material such as sand.

Another source of particulates is char formed when the biomass feedstock is incompletely gasified. Char particles undergo devolatilization and subsequent reactions at gasification temperatures that leave them less reactive than fresh biomass feedstock. These particles may pass through the gasifier before they are completely gasified, particularly in gasifiers with turbulent beds. Char entrained in the product gas also represents unconverted biomass that contributes to lower conversion efficiencies. Large-scale gasifiers can obtain carbon conversion efficiencies of 98-99%, meaning that about 1-2% of the carbon in the feedstock remains as solids. Collection of this material and subsequent re-injection of the char into the gasifier can increase overall gasification efficiencies.

Particulates, while unavoidable in biomass gas streams, are undesirable. Mineral matter can abrade and damage downstream equipment, and most emission regulations limit the amount of fly ash that can be present. Systems to control particulates will be needed in essentially all large scale biomass gasification systems.

Table 3.1. Inorganic content of biomass feedstocks (Klass, 1998)

Material	Inorganic Material, dry wt ⁰ %	Higher Heating Value, MJ/dry kg
Woody		
Cottonwood	1.1	19.5
Hybrid poplar	1.0	19.5
Loblolly pine	0.5	20.3
Eucalyptus	2.4	18.7
Herbaceous		
Switch grass	10.1	18.0
Sweet Sorghum	9.0	17.6
Miscellaneous		
Rice Straw	19.2	15.2
Paper	6.0	17.6
Cattle manure	23.5	13.4
Brown kelp	45.8	10.3
Pine Bark	2.9	20.4
Coal and Peat		
Illinois Bituminous	8.7	28.3
North Dakota lignite	10.4	14.0
Peat	7.7	20.8

3.2.2 Alkali Compounds

In addition to the quantities of mineral matter present, the composition of that material must be considered. The chemical composition of the ash determines the physical properties of the material such as softening, melting points, or vaporization points. The chemical composition of ash from some biomass feedstocks is summarized in Table 3.2. As shown, biomass feedstocks may contain significant amounts of alkali salts, particularly potassium. Potassium is an element required for plant growth, and concentrations are particularly high in rapid growth biomass such as grasses or related energy crops.

Table 3.2. Composition of ash from selected biomass (Klass, 1988)

	Ash Composition by Constituent, Dry wt ⁰ %							
	CaO	K ₂ O	P ₂ O ₅	MgO	Na ₂ O	SiO ₂	SO ₃	Other
Hybrid Poplar	47.2	20.0	5.0	4.4	0.2	2.6	2.7	17.9
Pine	49.2	2.6	0.3	0.4	0.4	32.5	2.5	12.1
Switch grass	4.8	15.0	2.6	2.6	0.1	69.9	1.9	3.1

The high alkali content of some biomass feedstocks can create significant gas cleanup challenges. Eutectic sodium and potassium salts in the ash material can vaporize at moderate temperatures of about 700 °C. Unlike the solid particulates that can be separated by physical means such as barrier filters, the vaporized alkali compounds will remain in the product gas at high temperature. As a result, the alkali vapors cannot readily be removed from the hot gas stream by simple filtration. Condensation of the vaporize alkali typically

begins at about 650 °C on particles in the gas stream, with subsequent deposition on cooler surfaces in the system such as heat exchangers, turbine expansion blades, or similar areas.

Table 3.3 Concentration of alkali in fuel (Miles, et al., 1996a)

Biomass feedstock	Alkali oxides (kg/GJ)	Fouling/slugging probability
Yard waste	.50	Very high
Wood-Almond Shell mix	.40	Very high
Forest residuals	.22	Medium
Hybrid poplar	.17	Some
Red Oak	.09	Low

The problem of alkali deposition in biomass fueled turbine systems was particularly evident in research during the 1980s that used a direct combustion gas turbine system (Hamrick, 1991). Although particulate loadings at the turbine inlet met manufacturers specifications, a glassy ash material rapidly deposited on the blades of the expansion turbine at inlet temperatures above about 785 °C. The problem arose from alkali vapors that passed through gas cleanup systems and deposited as the gases cooled during expansion. While the combustion system had higher turbine inlet temperatures than would typically be seen with biomass gasifiers, the potential problem of alkali vaporization/deposition must still be addressed in gasification applications.

Over the past fifteen years, a much better understanding of the alkali vaporization and subsequent ash deposition phenomena has been developed (Miles, et al., 1996a, 1996b; Jenkins, et al, 1998; Baxter, et al., 1997a, 1997b, 1992; Dayton, 1997, 1994). Ash vaporization involves a complex interaction of the alkali salts in the biomass. During combustion or gasification, alkali salts in the biomass vaporize to form products such as KOH and KCl, which in turn react with chlorine and sulfur. Although most biomass feedstocks have naturally low levels of sulfur, even the naturally occurring concentrations can lead to alkali vapor formation. The resulting eutectic salt can vaporize at modest temperatures of 700 °C or higher. Vaporized alkali salts can readily pass from the combustor through clean-up systems such as cyclones, and finally deposit on cooler down-stream components.

While alkali vapor formation is less of a problem in gasification than in combustion systems, it must be addressed to avoid unwanted problems. Biomass gasification in turbulent flow gasifiers typically used at large scale occurs at around 900 °C, which is higher than the temperature required to vaporize alkali salts. As a result, vaporized alkali salts may be present in the hot products exiting from typical large-scale gasifiers. Cooling the gas will result in condensation of the vapors into fine solids. Unless the solids are effectively removed from the gas stream, however, they can be re-volatilized in hot regions such as combustors downstream from the gasifier.

The importance of removing alkali material from the biomass gas steam will depend on the end-use for the gas. The problem of alkali vapor formation and deposition is particularly critical in systems where the hot gasifier product is to be used without significant cool-down. Moderate cooling of the gas followed by removal of bulk particulates provides adequate cleaning for simple boiler systems that can tolerate some ash deposition. Other applications such as gas turbines will require significantly cleaner fuel gases. Turbines operate at high rotational speeds, and deposition can cause rapid imbalance and

catastrophic failure. For these demanding systems, thorough alkali removal of fine particles or aerosols of alkali salts is necessary.

Even in systems where deposition of hot vapors is not a problem, the presence of alkali salts may create other problems. Alkali salts can be corrosive to metal surfaces and can inactivate catalysts such as those in tar cracking and synthesis gas applications. The methods to eliminate alkali and alkali salts from the gas stream are discussed in Section 3.3.1.

3.2.3 Tars from Biomass Gasification

“Tar” is a generic term describing a complex range of oxygenated organic constituents that are produced by the partial reaction of the biomass feedstock. Such materials reside in the hot gas stream as vaporized material or as persistent aerosols, but typically condense at cooler temperatures. These tars include a variety of oxygenated aromatics formed in the pyrolysis step of the gasification process. The definition of the term “tars” has been actively discussed over the past few years without conclusive resolution. For this discussion, tar is defined as organic molecules with weights greater than that of benzene 78. This definition has been used in some other references to tar formation in biomass gasification systems. (Neeft, et al, 1999).

The composition of the tar is complex and highly dependent on the severity of reaction conditions encountered, including gasification temperature and residence time in the reactor. The mechanisms of tar formation have been reviewed elsewhere in detail (Evans and Milne, 1997; Milne, et al., 1997, Neeft, et al, 1998). As biomass is heated, it dehydrates and then volatilizes as it thermally decomposes. The volatilized material can either undergo further decomposition to form permanent gases, or it can undergo dehydration, condensation, and polymerization reactions that result in tar formation. The tar composition is based on the “severity” of conditions it encounters including temperature and residence time at temperature (Evans and Milne, 1987). A general correlation between temperature and tar composition is shown below with temperature rising from about 450 °C on the left to about 950 °C on the right (Baker, et al, 1986).

Mixed oxygenates	phenolic ethers	alkyl ethers	heterocyclic ethers	polyaromatic hydrocarbons(PAH)	larger PAH
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The tar varies in composition from primary oxygenated pyrolysis products at lower temperatures to high molecular weight, deoxygenated products for those that have experienced severe reaction conditions. Tars from updraft, fixed-bed gasifiers are composed primarily of mixed oxygenates and phenolic ethers because they are produced at moderate temperatures. By comparison, tars formed at high temperatures in circulating fluidized bed gasifiers contain heterocyclic ethers and polyaromatic hydrocarbons.

As described in Section 2, the amount of tar will also vary significantly depending on the design of the gasifier. Large-scale, turbulent bed gasifiers typically have tar concentrations in the range of 1 - 15 g/Nm³ while fixed-bed downdraft reactor designs typically produce tar concentrations of 20 - 100 g/Nm³ (see table 2.1). Fixed-bed downdraft gasifiers have the potential to produce very low levels of tars, less than 0.1 g/Nm³, but typically produce concentrations of 0.5 - 1.5 g/Nm³. Clearly gasifier design is an important consideration for systems where the end-use application is sensitive to the presence of tar. However, since large-scale systems will primarily use turbulent bed gasifier designs, the gas conditioning system must deal with tars characteristic of these technologies.

Tars in the product gas can be tolerated in some systems where the gas is used as a fuel in closely-coupled applications such as burners. In these situations, cooling and condensation of the tars can be avoided, and the energy content of the tars adds to the calorific value of the fuel. In more demanding applications, however, tars in the raw product gases, even at low concentrations, can create major handling and disposal problems. Tars readily condense on cool components downstream from the gasifier, resulting in plugging and fouling of pipes, tubes, and other equipment. In temperature regions above about 400 °C, the tars can undergo subsequent dehydration reactions to form solid char and coke that further plugs systems. The tars represent a cleanup problem and may be classified as hazardous wastes for disposal purposes.

In addition, the presence of tars in the product gas is highly undesirable in synthesis gas or hydrogen applications. Tar formation represents a reduction in gasification efficiency since less of the biomass is converted to a fuel or synthesis gas. More importantly, tars would degrade the performance of those systems. Tars can deactivate reforming catalysts, and fuel cell toleration of tars is likely to be low.

The formation of tars and their impact on biomass gasification systems has recently been reviewed in detail (Neeft, et al, 1999; Barker 1998). The technologies for tar removal from the product gas are discussed below in section 3.3.

3.2.4 Nitrogen Containing Contaminants

The primary nitrogen-containing contaminant in the raw gas from biomass gasifiers is ammonia, NH₃. Ammonia is formed from the protein and other nitrogen-containing components in the biomass. High-protein feedstocks such as animal wastes or alfalfa will result in greater ammonia production. Ammonia production is also higher in pressurized gasifiers due to equilibrium considerations and in pyrolytic (rather than air or oxygen-blown units) due to the reducing environment in those gasifiers.

The acceptable levels of ammonia in the gas stream are typically dictated by local regulations. Gasification systems must necessarily meet these emissions regulations, but the concentrations of ammonia are relatively low with common feedstocks in most gasifiers. Ammonia in the product stream is undesirable primarily because it leads to the formation of NO_x emissions when the product gas is burned. Cleanup of the ammonia is therefore required for systems in locations with strict NO_x regulations.

NO_x is also produced in some gasifiers but is generally not present in high enough concentrations to create problems. NO_x is produced by the reaction of nitrogen or nitrogen-containing molecules with oxygen at elevated temperatures representative of those in combustion systems. The lower temperatures in gasification and the nature of the reactive environment limit NO_x production.

Although the gasifier product itself has low levels of NO_x, the total systems emissions of this product must be carefully considered. When the clean biomass fuel gas is eventually burned, NO_x will be produced, as it is in most combustion systems with all fuels. The use of fuel gases rather than solid biomass fuels provides the opportunity to better control the combustion process, which can potentially result in lower NO_x emissions. For this reason, gasification offers potential environmental emissions advantages over combustion alternatives. However, NO_x may still occur as the gas is burned, and appropriate NO_x

control technologies may be necessary. Additional information on NO_x cleanup is provided in Section 3.4.

3.2.5 Sulfur

Sulfur in the biomass feedstock can be converted to hydrogen sulfide or sulfur oxides during gasification, depending on the gasification approach. Most biomass feedstocks contain low percentages of sulfur. Wood typically contains <0.1% sulfur by weight, and herbaceous crops may contain 0.3–0.4% (Klass, 1998). A few feedstocks such as refuse-derived fuel (RDF) may contain 1% or more, approximately the same as bituminous coal. As a result of the low levels of sulfur in the biomass, the concentrations of H₂S and SO_x levels in the product gases are below those requiring cleanup in most applications.

The low concentration of sulfur in biomass offers potential advantages for some applications. In cofiring applications, for example, the cleaner combustion gases from biomass dilute those from coal, and the overall concentrations of sulfur per unit of combustion gas are reduced. In most applications where the biomass product is used as a fuel gas, technologies to remove sulfur will not be needed.

Sulfur, however, is a potential problem even at low levels for synthesis gas systems using certain types of catalysts. The production of methanol from synthesis gas, for example, uses catalysts that are poisoned by sulfur. Some tar cracking catalysts are also sulfur sensitive. In those systems, thorough removal of sulfur will be required. Fuel cell systems are also sulfur sensitive.

3.2.6 Other Considerations for Synthesis Gas

Gasifier products used to synthesize liquid fuels and chemicals must also be cleaned to remove the impurities described above. Synthesis gases must be further conditioned to remove other unwanted components including carbon dioxide and low molecular weight hydrocarbons such as ethane or methane. These components, which would be harmless or even helpful in fuels systems, both dilute the synthesis gas and can affect synthesis catalyst performance. The gas must have specified ratios of primary constituents carbon dioxide (CO₂) and hydrogen (H). Methanol synthesis, for example, requires a H₂/CO ratio of somewhat over 2:1. Liquid fuels have been synthesized from coal for decades in South African and elsewhere, and the technology is well developed and available commercially. Synthesis gases from biomass feedstocks can equally well be used in these technologies if the gases are appropriately cleaned and conditioned. Technologies to condition synthesis gases are discussed in Section 3.3.6 and 4.4.1.

3.3 Gas Cleanup Technologies and Recent Progress

As noted above, the contaminants in the raw product gas are incompatible with many end-use systems, and gas cleanup and conditioning will be required in those systems. Various technologies can potentially be used to remove unwanted components from the gas stream, including particulates, alkali, tars, sulfur, and ammonia. The gas cleanup and conditioning technologies for biomass gasification systems are outlined and recent progress with

technology components are discussed below. In practice, the gasifier and the gas conditioning technologies must be considered as integrated systems. Integrated gas cleanup and conditioning systems are discussed in Section 4 of this report.

3.3.1 Particulate Removal Technologies

Particulate removal requirements vary significantly depending on the use of the product gas. For example, particulate levels must be reduced to below 50 mg/Nm³ for gas engines (Abatzoglou, et al., 2000), to below about 15 mg/Nm³ (> 5µm) for turbines (see Section 4.0), and to perhaps 0.02 mg/Nm³ for synthesis gas systems (Graham and Bain, 1993). The primary types of systems include the following, although others have been proposed and sometimes tested:

- Cyclonic filters
- Barrier filters
- Electrostatic filters
- Wet Scrubbers

These particulate removal technologies and recent progress in certain areas is discussed in more detail below.

3.3.1.1 Cyclone Filters

Cyclonic filters are a primary means of removing bulk particulates from gas streams. They use centrifugal force to separate solids from the gas by directing the gas flow into a circular path. Because of inertia, the particulates are unable to follow the same path and are separated from the gas stream. Although the physics of particulate removal are quite complex, cyclone filters with predictable performance can be designed in a straightforward manner using theoretical and empirical techniques developed over many years.

Cyclonic filters (and closely related designs such as “U” tubes) are routinely used as an initial gas cleanup step in most gasifier systems because they are effective and relatively inexpensive to build and operate. In circulating fluidized bed or entrained bed gasifiers, cyclones are an integral part of the reactor design providing for separation of the bed material and other particulates from the gas stream.

Cyclone filters are particularly effective at removing larger particles and can operate over a wide range of temperatures, limited primarily by the material of construction. Cyclone filters, frequently designed as multiple units in series (multi-clones), can remove >90% of particulates above about 5 µm in diameter at minimal pressure drops of 0.01 atm. Partial removal of material in the 1–5 µm range is also possible, but cyclonic filters become ineffective with sub-micron particles. Since cyclone filters can operate at elevated temperatures, the sensible heat in the product gas can be retained.

Cyclone filters also remove condensed tars and alkali material from the gas stream, although the vaporized forms of those constituents remain in the gas stream. In practice, the separation of significant amounts of tars from the gas stream may be done sequentially by first removing particulates at higher temperatures where tars remain vaporized. The gas stream is then cooled and condensed tars are removed. The step-wise approach reduces the tendency of particulate material to stick to tar-coated surfaces and contribute to plugging.

Cyclonic filters are used extensively in many processes and are available commercially from many vendors. This is a commercially mature technology, and the future improvements are likely to be incremental.

3.3.1.2 Barrier Filters

Barrier filters include a range of porous materials that allow gases to penetrate but prevent the passage of particulates. These filters effectively remove small-diameter particulates in the range of 0.5 to 100 μm in diameter from gas streams. Barrier filters can be designed to remove almost any size of particulate, including those in the sub-micron range, but the pressure differential across the filter will increase as the pore size decreases. As a result, there are technical and economic constraints which effectively limit particulate removal to about 0.5 μm in systems such as gasifiers that must handle large gas volumes.

Barrier filters are cleaned by periodically passing pulsing clean gas through the filter in the reverse direction of normal gas flow. To reduce the overall particulate load, these filters are typically placed downstream from cyclone filters. Barrier filters are effective for removing dry particulates but are less suitable for wet or sticky contaminants such as tars. Tars cling to the filter surface and can undergo subsequent carbonization reactions that lead to fouling and plugging. Even in the absence of further decomposition, tars are difficult to remove from these materials.

Examples of barrier filters suitable for biomass systems include:

- rigid, porous “candle” or cross-flow filters constructed of metal or ceramic
- bag filters constructed of woven material
- Packed bed filters

Rigid barrier filters, sometimes called hot gas filters, provide a potential opportunity to produce a clean fuel gas while retaining the sensible heat of the fuel gas. In larger-scale biomass gasification systems, these systems can potentially operate at moderate to high temperatures, depending on their material of construction, while removing small particulates. In most cases, cyclones would be used to reduce the overall loading of particulates before passing the gas through barrier filters for “finishing.”

These types of barrier filters are used in other industries for particulate removal, but they have been only recently tested in biomass gasification systems. In large-scale biomass systems, the use of metallic barrier filters may require partial product gas cooling to prevent sintering of the metal. In addition, metal filters are also susceptible to corrosion. Ceramic filters are suitable for higher temperature operation but are fragile and can break from thermal stress during temperature cycling. Ceramic filters are also susceptible to reactions with alkali vapors in gasification systems that can lead to decomposition or plugging.

Recent RD&D on larger-scale biomass gasifiers has led to improved understanding of the potential of rigid barrier filters. This interest has grown from the desire to provide a straightforward method to remove particulates and perhaps alkali from the product gas while also retaining most of the heat content. Providing clean gases while also preserving the sensible heat of the gas is particularly important in closely coupled gasifier/gas turbine systems. Barrier filters have been tested and shown to have potential in several recent gasification demonstration systems.

Ceramic and metal candle-type filters were both tested at a commercial demonstration facility at Värnamo, Sweden that was in operation through late 1999 (Sydkraft, 1998). This integrated gasification combined cycle (IGCC) facility consisted of an air-blown, pressurized fluidized bed gasifier coupled to an Ahlstrom gas turbine. The system capacity was approximately 6 MW_e. In the tests at Värnamo, the gasifier gas was first cooled to about 350 °C in a heat exchanger, and the resulting “warm” gas passed through candle filters. Some breakage of ceramic candle elements was encountered in early tests. These problems were caused in part because of the frequent thermal cycling in the demonstration facility that operated intermittently. Later tests at Värnamo were made with metallic candle filter elements, which are suitable for use with the “warm” gas at 350 °C. The gasifier facility operated successfully in its full gasifier/gas turbine power generation mode for extended periods using these filters. The facility, closed in 1999, is described in more detail in Section 4 of this report.

Ceramic candle filters were also tested at a research and development gasifier facility in Hawaii in the mid-1990's (Wiant, 1998, 1994a, 1994b; Lau, 1998). In that demonstration facility, gas was produced at about 980 °C, and a slip-stream was diverted to a hot-gas cleanup unit. The gas was first cooled to about 700 °C by water injection and then passed through ceramic candle filters. The filters were cleaned at ~30 minute intervals using pressure pulses. Tests totaling about 170 hours of operation were performed, and the barrier filters worked well during that period. The filter elements maintained mechanical integrity even with large temperature fluctuations, and no evidence of plugging or bridging was found. Measurements of particulate loading in the cleaned gas were not reported. The termination of the gasifier project in early 1998 prevented extended tests to determine the longer-term viability of these filters.

Bag filters are composed of woven material that intercepts small particles on the filter surface by impingement and electrostatic attraction. The efficiency of collection increases as the depth of the filter cake increases, making these filters highly efficient for small diameter, even sub-micron particles size. Filters are periodically shaken or back-flushed to remove particulate accumulation. These filters are usually constructed of woven materials suitable for operation at low temperature operation up to about 350 °C.

These filters are well proven for removing particulates in a variety of systems but have not previously been used in biomass gasification systems. In biomass systems, these filters require hot product gas to be cooled prior to filtration. For that reason, they are most appropriate for applications where retaining the sensible heat of the product gas is not critical. In addition, the presence of tars in the product gas can cause potential problems since tar condensation on the filter cake or the filter itself can lead to plugging. Care must be taken to ensure that tars are either removed from the stream prior to the bag filter or that the temperature remains high enough to prevent tar condensation.

Bag filters are being used or have been proposed for several medium- and large-scale gasifiers. These include systems using steam-based and gas turbine based power generation technologies. In both types of systems, the product gases are typically cooled below 300 °C and passed through bag filters.

Examples of bag filter use in steam-based power generation systems include the Amer Power Station in Geertruidenberg, Netherlands (EPZ, 1999). This facility uses a circulating fluidized-bed gasifier to convert urban wood wastes into fuel gas. The resulting fuel is cofired in a coal-burning steam generation combined heat and power facility. This is

currently the largest biomass gasification facility in the world and has a thermal output of about 85 MW_t. In the facility, the gas is cooled to about 240 °C in a heat exchanger, passed through a cyclonic filter for bulk solids separation, and then passed through bag filters prior to wet scrubbing. The facility was beginning shakedown operation in early 2000, so operating data from the facility is currently unavailable. This system is discussed in more detail in Section 4 of this report.

Other large-scale gasification facilities that will use bag filters in gas turbine-based systems are currently in the planning and construction stage. The Arable Biomass Renewable Energy (ARBRE) project in UK (ARBRE, 1999) and the Bioelectrica project in Italy (DeLang, 1998) are currently being constructed. Both of these gasification facilities are based on similar designs using circulating, fluidized bed air-blown gasifiers to produce a low-energy gas. The raw gas will be cooled in a heat exchanger, passed through cyclones for bulk particulates removal, and then passed through bag filters for additional cleaning. Tars will be removed by wet scrubbing following the filtration steps. Because both of these facilities are still being constructed, operational data is not yet available. These projects are discussed in more detail in Section 4 of this report.

Packed-bed filters, while quite different in operation, may also act as barrier filters. In these systems, the raw product gases pass through a bed of packing material such as ceramic spheres or sawdust. Gas phase products pass through the bed, and particulates are de-entrained from the gas flow. Periodically, the particulates must be removed from the filter bed, typically by back flushing. Small-scale gasifier facilities have used packed beds of materials such as sawdust or activated charcoal to remove both particulates and tars from the gas stream. In larger systems, the problem with accumulation of particulates or tars in the packed bed present potential operability problems. As a result, these types of filters are not being actively incorporated into larger-scale gasifier systems at this time.

3.3.1.3 *Electrostatic Filters*

Electrostatic filters have also been used extensively in a variety of gas cleaning operations. In these systems, the product gas flows past high voltage electrodes that impart an electric charge to particulates, but do not affect the permanent gases. The particulates are then collected as the gas stream passes collector plates of the opposite polarity. The electrically charged particulates migrate to the collector plate and deposit on the surface. Particulates are removed from the scrubber plates by either wet or dry methods. Dry scrubbers use mechanical action to periodically remove material from the surface and can operate at temperatures of 500 °C or more. Wet scrubbers remove particulates with a thin film of flowing water and are limited to temperatures of about 65 °C.

Electrostatic filters have been used in many coal-fired power stations, and they have been used in some biomass combustion facilities. Their use in medium- or large-scale gasification systems is limited. Electrostatic filters are best suited for large-scale operation due to their physical size and cost, and the primary impediment to their use in current gasification systems is an economic one. Two systems producing fuel for gas engines including the Easymond AG gasifier in Boizenberg, Germany and the Harboore gasifier in Denmark have electrostatic filters (BTG, 2000). These systems have electrical generation capacities of about 3.5 and 1.0 MW_e respectively.

In both cases, gas is produced using updraft, fixed bed gasifiers. In the German facility, the gas is first cooled and then passed through a cyclone and a catalytic tar cracker. The

electrostatic precipitator (dry) is located downstream to remove further particulates. In Harboore, the system does not have a tar cracker and the cooled gases pass from a cyclone directly into a wet electrostatic precipitator. In both cases, the product gas also passes through a wet scrubber before it is used.

3.3.1.4 *Wet Scrubbers*

Wet scrubbers use liquid sprays, usually water, to remove particulates. Particles are collected by collision with liquid droplets, and the droplets are then de-entrained from the gas stream in a demister. The most common wet scrubbers use a venturi design to create a pressure drop that allows solutions to be easily sprayed into the gas stream. Gas velocities are typically 60–125 m/sec in this throat area. Particulate removal efficiency is proportional to the pressure drop across the venturi. With pressure drops of between 2.5–25 kPa, these scrubbers can remove 99.9% of particles over 2 μm , and 95–99% of those over 1 μm (Baker, et al, 1986).

The wet particulates from the venturi are subsequently removed from the gas stream by a demister. The demister can be a cyclone, packed bed, or other type of collector. Wet scrubbing requires that the water remain in the liquid phase, which requires that the product gas be cooled to below 100 °C. This loss of sensible heat may be undesirable in some systems.

Most biomass gasification systems that currently use wet scrubbers do so primarily as a means to remove tars rather than particulates from the gas stream. Removing the particulates separately can prevent condensation of the sticky tars on the particulate surface, and that can prevent fouling and plugging of filter surfaces. The topic of wet scrubbers for removing tar from the product gas is discussed in more detail in Section 3.3.3 of this report.

3.3.1.5 *Standardized Particulate Measurement*

While the necessity of removing particulates is understood, the ability to consistently measure particulate levels in different biomass gasification systems has sometimes been difficult in the past. Recently, standardized particulate measurement protocols have been proposed both for large-scale (Simell, et al, 2000) and small-scale (Abatzoglou, et al, 2000) gasifiers. These protocols have been developed both for particulates and tars, as discussed in Section 3.3.3 of this report. The work is being assisted by the IEA Biomass Gasification Task (IEA Bioenergy 2000), the European Commission DGXVII, and the U.S. Department of Energy. The protocols should provide for a consistent method to evaluate particulate removal technologies at different gasification facilities.

3.3.2 Technologies for Alkali Removal

As discussed in Section 3.2, the mineral matter in biomass contains high levels of alkali salts, particularly those containing potassium. At temperatures of about 800 °C, the alkali salts can vaporize and create problems by depositing on cooler surfaces downstream. Since turbulent bed gasifiers typical of those used in large-scale systems achieve bed temperatures of 700–900 °C, alkali vapors are likely to be present in many systems. The alkali will remain as a vapor in the gas until it condenses due to cooling below about 650 °C. The vapors can condense to form small (<5 μm) particulates or can condense on surfaces such as other particulates or other system surfaces. Removal of this condensed material is important in

some applications such as gas turbines since it can re-vaporize at the high-temperatures encountered in subsequent combustion zones.

In current gasification systems, alkali vapors are removed by cooling the hot product gas below about 600 °C to allow for condensation of the material into solid particulates. The solids are then removed using various filtration systems as described above. In systems that are sensitive to deposition of alkali salts, filtration systems must account for the small particle size and the chemical behavior of the condensed material. Cyclones, for example, will be ineffective at removing the <5 µm solids. In addition, the alkali may cause corrosion to ceramic or metallic barrier filters. Recent progress has been made on providing better methods to analyze alkali in the gas stream (Smeenk, et al, 1999). As the potential for alkali vapor formation has become better understood, the methodology to analyze for this material is also being developed.

At present, the most effective method to remove alkali is to cool the gas product to lower temperatures where technologies such as electrostatic filters, bag filters, or wet scrubbers can be used to remove the small particulates. These systems, while effective, require cooling of the product gas and the accompanying loss of sensible heat that may reduce system efficiency.

Recent research has shown that alkali “getters” may be effective at removing alkali from the gas stream at high temperature (Turn, et al, 1999). Hot gases from a bench-scale gasifier were passed through a ceramic filter and then into packed-bed filter loaded with activated bauxite. The gasifier was operated at about 825 °C, and the bauxite filter at 650–725 °C. A comparison of the measured gas phase concentration of Na, K, and Cl is shown in Table 3.4

Table 3.4 Alkali filtration results (Turn, et al, 1999)

Alkali	Measured concentration without bauxite filter, ppmw	Measured concentration with bauxite filter, ppmw
Na	28	0.07
K	11	0.58

The use of the hot gas filter reduced sodium and potassium concentrations in the product gas by more than an order of magnitude. The authors noted that chlorine removal in the test system was incomplete but suggested that improvements could be made by revising the filter design. While this approach has not yet been tried in a larger-scale system, the results suggest that alkali getter systems may be an effective way to remove alkali while preserving the heat content of the product. Additional research and development activities on this concept will be needed.

3.3.3 Tar Removal Technologies

As discussed previously, removal of tars from the gas stream is important in most gasification systems. As the product gas cools, vaporized tars will condense either onto cool surfaces or into aerosols of small droplets. The size distribution of these aerosols is poorly characterized in the open literature, but probably includes material less than 1 µm in diameter. The difficulties in characterizing the tars arise in part from the lack of consistent tar sampling and measuring procedures. Recent work in the development of such protocols is discussed in Section 3.3.3.4 below.

Tar removal is particularly necessary in systems where the gas is cooled prior to use since condensation in pipes and other equipment will lead to operational problems. Tar removal is also critical in systems where the gas must be compressed prior to use and in some mechanical systems such as piston engines. A recent review of tar removal from biomass gasification systems can be found elsewhere (Neeft, et al, 1999).

In those systems that are sensitive to tar formation, it is important to minimize tar production in the raw product gas exiting from the gasifier. This can be done in part by selecting and optimizing gasifier designs that produce lower concentrations of tar, as summarized in Table 2.1. Matching gasifier performance with end-use application is a crucial first step to preventing problems with tar accumulation. However, tars are formed in all biomass gasifiers, and the overall systems must be designed to address this issue. Tar formation not only contributes to operational problems but also represents a reduction of gasification efficiency. Tars removed from the gas stream can also be difficult to dispose of, as discussed in more detail below. The collected tars are wet and may be classified as hazardous waste, particularly if they were formed at high temperatures.

The raw product gas from the gasifier contains tars in vaporized form, as aerosols of condensed tars, or as combinations of both. Two basic approaches have been used to remove tars from product gas streams. Most commonly, condensed tar droplets are physically removed using technologies similar to those used for particulate removal such as wet scrubbers, electrostatic precipitators, or other technologies. These require that the product gas be cooled to ensure the tars are in a condensed form. In addition to physical methods of removal, catalytic and thermal tar reduction methods are being developed that convert the tars to permanent gases. The catalytic approaches can potentially destroy tars in either the vaporized or condensed state. These two approaches are discussed below.

3.3.3.1 *Technologies for Physical Tar Removal*

At present, tars are most frequently removed from the gas stream by cooling the product gas to allow tar condensation into aerosol droplets and then removing the droplets using technologies similar to those for particulate removal. These technologies include wet scrubbers, electrostatic precipitators, or cyclones. Particulates are removed separately from tars. While it is possible to remove both simultaneously, the condensation of “sticky” tars on particulate surfaces can lead to plugging and fouling of gas conditioning equipment.

Wet scrubbers collect tars through the impingement of the material on water droplets. The tar and liquid flow to a demister or decanter and the bulk tars are separated from the aqueous phase. The use of water in these scrubbers requires the gas temperature at the exit be in the range of 35–60 °C. Research using oils as scrubber fluids in biomass systems has also been performed but these designs have not gone past the experimental stage of development (Bridgwater, 1995).

A wide variety of scrubber designs are available including spray towers, impingement scrubbers, baffle scrubbers, and venturi scrubbers. These technologies are described in more detail elsewhere (Baker, et al, 1986; Reed and Das, 1998). The relationship between complexity and efficiency of these scrubbers vary as shown in Table 3.5. Wet scrubbers have been used extensively in the coke-oven and the gas processing industry, and their performance is well characterized in those applications. In these applications they are fully mature technologies available from commercial vendors.

Table 3. 5 Relative efficiencies of tar removal for wet scrubbers (Baker, et al, 1986)

	Pressure drop, cm water	Particle size (μm) for 80% collection
Spray Tower	1.5 - 4.0	10
Impingement	5 - 125	1 - 5
Packed Bed	5 - 125	1 - 10
Venturi	10 - 250	0.2 - 0.8

Wet scrubbers have also been used in numerous biomass gasification systems, but the actual operational performance of these scrubbers is decidedly mixed. The performance of various types of scrubbers is summarized in Table 3.6:

Table 3.6 Reported tar removal efficiencies of wet scrubbers in biomass gasification systems (Neeft, et al, 1999)

Technology	Tar removal efficiency
Spray tower	11 - 25% heavy Tars 40 - 60 % PAH 0 - 60 % phenolics
Spray tower	29% heavy Tars
Venturi Scrubber	50 - 90 % not given
Venturi and Spray Scrubber	83 - 99 % condensable material
Venturi + cyclonic demister	93 - 99% condensable organics
Vortex scrubber	66 - 78% evaporation residues

For large-scale systems, research and demonstration projects have shown that wet scrubbers have the potential to effectively remove tars. In those systems, the gas is cooled to about 240 °C or below, and bulk particulate removal is performed prior to tar removal. The gas is further cooled and passed through a wet scrubber. Examples of large-scale gasifiers with scrubbers for tar removal include the Amergas facility in Netherlands which is undergoing shakedown operation, and the ARBRE and Bioelectrica facilities in Europe that are under construction. These facilities are discussed in more detail in Section 4 of this report. While operational data from these facilities is not yet available, these scrubber systems are based on successful experience gained in previous research. This research and development work has included demonstration of these technologies in development scale facilities by groups such as TPS in Sweden (Rensfelt, 1998).

The use of wet scrubbers in small-scale biomass gasification systems has proven to be a less reliable method to remove tars. The types of scrubbers that are economical for small systems are not always effective at removing tars. Simple spray towers, for example, may remove less than half the tars in the product gas as shown above. Tar production in small-scale gasifiers is also susceptible to changes in feedstock moisture content. Higher than expected feedstock moisture content reduces internal gasifier temperatures and leads to additional tar formation. The problem is more noticeable in small-scale systems that can rapidly depart from steady-state operating conditions due to low thermal mass. The costs of tar utilization or disposal also have greater economic impact on small-scale gasifiers. Based on operational experience over the past several years, there is evidence that using water scrubbing systems alone to clean tar-laden gases in small-scale systems will not be practical on either an operational or cost basis unless major improvements are made to current systems. This suggestion, however, remains controversial.

Wet electrostatic precipitators can also be used to remove tars from product gas streams. Tar removal is based on the same principles as particulate removal, with ionization of the tar droplet followed by migration of the ionized droplet to a charged collecting point. For tar collection, wire and tube designs are preferred for the electrostatic precipitator rather than the plate collectors used for particulates. The collector surfaces are washed continuously to remove the tar material. These technologies can operate up to about 150 °C, but would likely operate at lower temperatures for tar removal to avoid tar vaporization.

Electrostatic precipitators are very efficient at removing either tars or particulates from the gas stream, and can remove up to 99% of materials under 0.1 µm in diameter. This technology is mature and available commercially for a variety of applications. The use of these systems with large scale biomass gasifiers, however, is uncommon. The high capital and operating costs of these systems are the primary barriers to their use. Tests with electrostatic precipitators have also been completed in small-scale systems (Hasler, et al, 1997), but operational difficulties were encountered.

Barrier filters of various types have been used in biomass gasification systems for tar removal. Tar is captured by impingement of condensed aerosols on the filter surface. Because it exists in a liquid form, tar is more difficult to remove from the filter surface than dry particulates. The problem of removing tars from the filter surface is compounded when particulates are also present because the resulting filter cake cannot be readily cleaned from filter surfaces. These differences in characteristics make many barrier filters less suitable for tar removal than for particulate removal. Barrier filters including fabric bag filters and rigid “hot gas” filters made of metal or ceramic are generally inappropriate for tar removal in biomass gasification systems. Tar accumulation on the filter surface leads to eventual plugging.

Packed bed filters have been used historically in many smaller-scale biomass gasification facilities to remove tars, and some research has recently been conducted on packed bed filters. Packing materials have included sawdust, wood chips, cork, and sand. While these packing materials provide adequate filtration of tars, they also create operational problems related to cleaning the filter and to waste disposal. These filters may be appropriate for small systems operating in remote locations where labor is inexpensive, but they are not being incorporated into designs for larger-scale commercial facilities due to operational and cost considerations.

Cyclone filters and other centrifugal force separators are also mechanical technologies that can potentially be used for tar removal. These technologies operate on the same principles as those for particulate removal, using centrifugal force to separate solids and aerosols from gases. Examples include cyclones, u-tubes, or vortex separators. The technologies are best suited for removing larger materials, typically those with diameters of 5 µm or greater.

In practice, cyclones and related centrifugal separators are not used for tar removal in biomass gasification systems. The combination of particulate and “sticky” tar in the gas stream creates a deposition of material on cyclone surfaces that is difficult to remove in normal operation. Even if particulates were removed prior to tar condensation, cyclones are ineffective at removing small-diameter tar aerosols that include material under 1 µm . As a result, cyclones are not a practical means of removing tars from raw biomass gasification products.

Recently, interest has been expressed in the use of other types of systems based on centrifugal force separation (Neeft, et al, 1999). These include the so-called “condi-cyclone” and the rotating particle separator, which are described in more detail by Neeft. The condi-cyclone has been used to remove water from gas streams, but no data has been reported for tar collection. Limited research using a rotating particle separator for tar separation has also been performed (Hasler, 1998; Berkel and Temmink, 1998). Further research will be required before the viability of these technologies for large-scale systems can be evaluated.

3.3.3.2 *Use and Disposal of Collected Tars*

Systems that physically separate tar must also deal with the waste products that are collected. In large-scale gasification systems, the most appropriate technologies for tar removal currently involve wet scrubbers or wet electrostatic precipitators. In either case, the tar is collected as part of an aqueous rinse. As discussed previously, biomass tars include a spectrum of organics ranging from mixed oxygenates to phenols to multi-ring aromatics, and most of these are at least partially water soluble. As a result, the wet scrubber waste from these technologies is recovered as an emulsion that cannot be cleanly separated into organic and oil-phase products. Partial separation of the effluent into “oil” and “water” phases can sometimes be achieved by settling, but the resulting oil product still contains large amounts of water, typically 50 wt% or more. The separated wastewater phase also contains lower molecular weight oxygenates including organic acids, aldehydes, and phenols that require cleanup. Both wastewater cleanup and tar disposal add economic costs and simple disposal is usually prohibited by environmental regulations.

Depending on the system, the collected tar material may be burned to provide process heat. Although the tar is wet and has a relatively low heating value, burners are commercially available that can utilize this fuel and provide heat to generate steam or to meet other system needs. In steam generation systems, for example, the heat from tar combustion can be used to generate additional steam and increase system efficiency.

Tars may also potentially be re-injected into the gasifier to produce additional product gas. Reinjection of tar, particularly material that is highly oxygenated, allows that material to further react and form additional gas-phase products. However, as tars are reheated, they also undergo further dehydration and condensation reactions to form more refractory tars. Thus, reinjection of tar into systems operating under steady-state conditions will result in partial conversion of the material to gases and partial conversion to more refractory tars. The equilibrium between the two depends on the specific system, but caution must be exercised to avoid buildup of highly aromatic, refractory tars by repeated exposure to severe reactor conditions.

Technologies capable of treating the aqueous wastewater are available but add cost to gasification systems. Adsorption of dissolved organics by carbon, wet oxidation of wastewaters, or dilution and biological treatment of wastewaters have all been shown to be technically feasible (Neeft, et al, 1999). The costs of such processes, rather than their technical feasibility, remain the primary constraint for gasification systems.

In addition to the disposal considerations, tar collection presents possible handling problems. Over the past two decades, the toxicological properties of a wide range of liquid products from biomass pyrolysis and gasification processes have been examined. This work (Diebold, 1998) suggests that tar-like products formed at temperatures of about 800 °C or less can safely be handled using standard “safe practices” such as eye protection, gloves,

and appropriate clothing. While these tars contain a wide range of chemical constituents, they do not present particular health risks if standard handling procedures are followed. Products formed at temperatures above approximately 800 °C or exposed to long residence times may also contain refractory polyaromatic products as explained above. Studies have shown (Elliott, 1985) that these refractory tars may contain materials that are classified as hazardous and will require a higher level of care in handling and disposal.

3.3.3.3 *Catalytic and Thermal Tar Destruction*

Catalytic or thermal tar destruction processes have also been examined as methods to remove tars from the product gas. In these processes, tars thermally decompose to form additional product gas and sometimes char. Tar destruction can be accomplished with thermal energy alone at above about 1200 °C or with catalysts at moderate temperatures of 750-900 °C. These approaches are intuitively attractive because they have the potential to increase conversion efficiencies while simultaneously eliminating the need for collection and disposal of tars. Such approaches are well suited to large-scale systems with turbulent-bed gasifiers where the product gas exits the reactor at temperatures of about 800 °C, the approximate range where catalytic destruction is most effective.

Catalytic processes for tar destruction

Catalytic tar destruction has been studied in biomass gasification systems for more than twenty years (see for example: Mudge, et al, 1981; Ekstrom, et al, 1982; Bridgwater, 1994; Beenakers, 1994; Simell, 1994; Aznar, et al, 1997; Abatzoglou, et al, 1997; Milne, et al, 1998, 1999; Neeft, 1999, Corella, et al, 1999, Caballero, et al, 1999). These processes use catalysts to assist in the cracking and destruction of tars. Research and development activities have been conducted using a variety of metallic and non-metallic catalysts either in the gasifier itself or in separate vessels downstream from the gasifier.

Research on catalysts placed in the gasifier (*in situ* tar destruction) began in the early 1980s and has continued intermittently since then (Baker, et al, 1986; Espenas and Frostäng, 1996; Sydkraft, 1998). Most of this research has focused on the use of low-cost dolomites and related "disposable" catalysts. Tars are cracked to smaller molecules on the catalyst surface, and the mechanisms of tar destruction are reasonably well documented. This conceptual approach has the potential advantage that tars can be rapidly destroyed as they are formed, eliminating downstream problems. The turbulent flow and high temperatures of large-scale fluidized bed gasifiers result in physical attrition and deactivation of the catalyst. In fixed-bed gasifiers, the contact between catalyst and tars is sometimes insufficient, resulting in incomplete tar destruction.

Testing to reduce tars in the gas stream using *in situ* dolomite catalysts has been reported at the Värnamo facility in Sweden (Sydkraft, 1998). The results showed that the catalyst was deactivated over time but that tar levels could be reduced. However, the Värnamo system did not require thorough tar removal, as will be explained in Section 4. At this time, research suggests the use of *in situ* tar destruction catalysts can reduce tar levels but this does not appear to be an effective approach for complete tar destruction in large-scale systems.

More extensive research has been performed on tar destruction systems where catalysts are placed in a separate reactor downstream from the gasifier (see for example: Neeft, et al, 1999; Paisley, 1997; Corella, et al, 1999; Aznar, et al, 1997, 1994). The separate reaction

vessel provides for better temperature control and for reduced bed turbulence that can contribute to longer catalyst lifetimes. This research has included examination of both metallic catalysts of the types used in the petrochemical industry and non-metallic catalysts such as dolomites as described below.

Extensive basic and applied research with *non-metallic catalysts* has been performed (Alden, et al, 1997; Orio, et al, 1997; Lammars, et al, 1997; Myrén, et al, 1997; Gebhard, et al, 1994a, 1994b; and other references from the previous paragraph). Non-metallic catalysts include dolomites, zeolites, and calcites. and the cost of these catalysts is generally low. The reactions of these catalysts with biomass tars have been examined extensively using a variety of analytical and modeling techniques. The research generally shows that dolomites and similar materials have significant potential to crack tars in biomass gasification systems. Under laboratory conditions, dolomite removes 95-99% of the tars in gas streams at temperatures of 750-900 °C. Dolomite can be deactivated through carbonate formation, and it is also sensitive to physical attrition due to bed turbulence. The use of less turbulent bubbling fluidized beds can prolong catalyst lifetimes.

Tests of non-metallic tar cracking catalysts have also been performed in biomass gasification development facilities. For example, a fluidized-bed tar cracker has been tested at the Battelle Columbus demonstration-scale (10 ton/day feedstock capacity) gasifier in the United States (Paisley, 1997). The tests used a proprietary disposable catalyst named DN34, which has been characterized in biomass systems by others (Gebhard, et al, 1994a, 1994b). Initial testing at this facility showed that wet scrubbing alone was insufficient to clean the gas prior to compression. To remove tars, the fuel gases were passed through a fluidized bed reactor containing a proprietary disposable cracking catalyst referred to as DN34 prior to wet scrubbing. At operational temperatures of 800 °C, tar concentrations were reduced from 23 g/m³ in the raw product gas to 1.4 g/m³ following the cracker (Paisley, 1997c). Tar reduction was dependent on the temperature, with low conversions at lower temperatures. Following the tar cracker, the product gases were then passed through a wet scrubber. Tar concentrations in the gas following the combination of wet scrubbing and catalytic cracking were reported to be “essentially zero”, or lower than detection limits (Paisley 1997c). The integrated system with the tar cracker operated for more than 200 hours. The larger-scale FERCO gasifier in Burlington, Vermont, is based on the Battelle-Columbus design and is discussed more in Section 4 of this report.

Extensive research has also been performed on the use of *metallic tar cracking catalysts* for biomass gasification. This work began in the early 1980s (Mudge, 1981) and has included studies of a wide range of metal-based catalysts including Ni, Ni/Mo, Ni/Co/Mo, NiO, Pt, Ru, on supports such as silica alumina, zeolites, and others (Aznar, et al, 1997; Alden, et al, 1997; and other references above). Many of these metal-based catalysts are used commercially in the petrochemical industry. Several of these, particularly those with Ni/Co/Mo blends, have been demonstrated to be effective in cracking biomass tars. They offer the additional advantage of also typically destroying ammonia in the gas stream as well. Catalyst lifetimes in the laboratory scale tests depend on the catalyst substrate. Commercial steam reforming catalysts can deactivate in a matter of hours, while others using zeolite supports maintained activity through numerous regeneration cycles using air to remove deposited carbon (Neeft, et al, 1999). At present, these types of catalysts have not been tested in larger biomass gasification systems under continuous, steady-state conditions. As a result, the technical information necessary to evaluate the technical and economic feasibility of metal-based tar cracking catalysts is not available, and additional testing will be needed.

Thermal processes for tar destruction

While catalysts facilitate tar destruction at intermediate temperatures, tars can also be cracked thermally without catalysts at higher temperatures, typically 1200 °C or higher. The minimum temperature required for efficient destruction is not well characterized and will depend on the types of tars formed in the gasifier. Thus, thermal destruction of the oxygenated tars from updraft gasifiers might be treated at 900 °C while the refractory ones from high temperature reactors may require 1200 °C or more. The difficulties of attaining complete thermal cracking along with operational and economic considerations make thermal cracking less attractive in current large-scale gasifiers using cleaner biomass feedstocks.

Thermal cracking has been tested for disposing of the tars from the pyrolysis or gasification of various organic wastes. For example, the Thermoselect process has been used to destroy tars produced during disposal of various wastes. In this process, O₂ is added to the reactor to partially combust the tars and increase temperatures to 1200 °C or greater. Similar approaches include the Noel Konversion process and the Bibros PEC process. These processes are reviewed elsewhere (Neeft, et al, 1999). Systems designed primarily for waste reduction, particularly hazardous wastes, have significantly different economic bases than energy systems. As a result, waste reduction processes may generate energy by-products that would be uneconomical if produced from clean biomass.

Thermal decomposition of biomass tars in electric arc plasmas has also been studied. Plasmas are created by heating gases in the discharge arc between two electrodes. The electrical charge and the increased temperature in the arc cause ionization of part of the gases and subsequent reaction. Several plasma arc reactors have been built and tested for applications with biomass tars and are reviewed elsewhere (Neeft, et al, 1999). At present, these systems have not been tested in continuous operation with larger-scale biomass gasifiers. These reactors have significant potential for waste elimination, and they could potentially be used to destroy tars accumulated by physical means as described above. However, they are unlikely to be appropriate as primary tar cracking technologies for large-scale biomass gasification systems due to the costs of electricity and the need to treat large gas volumes.

3.3.3.4 Standardized Testing Protocols for Tar Measurement

As stated previously, the measurement of tar concentrations in gasifier product streams is difficult. Because various labs and developers have historically used different methodologies, the data reported can be difficult to compare with that from other sites. The need for improved tar collection and measurement protocols has been recognized by the general gasification community.

As a result of this interest, suggested protocols have been developed for both small- and large-scale gasification systems. These protocols have been recently published (Maniatis and Beenackers; Abatzoglou, et al, 2000; Knoef and Koele, 2000; Simell, et al, 2000; Knoef, 2000). The proposed protocols provide standardized methods to analyze tars. The protocols are expected to improve the consistency and comparability of data obtained by different groups at different sites. While the complete analyses would probably not be made at large-scale facilities on an ongoing basis, periodic analysis using these protocols should produce much-needed data to the gasification research community.

3.3.4 Removal of Nitrogen Containing Compounds

Removal of ammonia from the biomass gas stream is necessary in many situations. Ammonia is converted to NO_x when the gas is burned, and NO_x emissions are limited by law in most industrialized areas. The imposition of stringent NO_x emission limits in many localities over the past ten years has focused additional attention on this issue. Two primary approaches are feasible for ammonia removal. Catalytic destruction of ammonia is possible using catalysts similar to those used for tar cracking or hydrocarbon reforming. Wet scrubbing will also remove ammonia in those systems where low temperature product gases are acceptable.

Catalytic destruction of ammonia has been reported for dolomites, nickel-based steam-reforming catalysts, iron-based catalysts, and others (Leppälähti, et al, 1994, 1991; Simmel, et al, 1997). Destruction of ammonia on the dolomite and nickel-based catalysts is effected at approximately the same temperatures as those used for tar cracking. Work with iron-based catalysts was also conducted at somewhat higher temperatures (about 900 °C). Using these catalysts, destruction of >99% of the ammonia is possible. This approach is appealing because it has the potential to remove both tars and ammonia from the product gas while maintaining the heat of the product gas. Research to date on catalytic ammonia destruction in biomass systems has been conducted primarily in bench-scale facilities, and additional work will be required to evaluate the cost and technical feasibility of this approach for large-scale gasification systems.

In systems where the product gas is first cooled, ammonia may also be removed from the product gas by wet scrubbing. Wet scrubbing is a well-developed technology used in related gas processing industries. Wet scrubbing is also used at the Amergas facility in The Netherlands to remove ammonia from the product gas (EPZ, 1999). The ammonia recovered from the scrubber is reinjected into the gasifier to provide for ammonia reduction through thermal equilibrium and to react with any NO_x formed during gasification. Although nitrogen oxides are formed primarily at temperatures representative of combustion systems rather than those found in gasification systems, the addition of ammonia will reduce NO_x level due to thermal equilibrium. The Amergas facility, as a "showcase" for utilization of urban wood waste, has chosen to provide a very clean product gas. The Amergas facility is currently undergoing shakedown operation, and long-term operational data was not available in late 2000.

3.3.5 Sulfur Removal

As mentioned previously, most biomass resources are naturally low in sulfur, and sulfur removal is not necessary in most applications where the product is used as a fuel gas. For those feedstocks such as wastes with unusually high sulfur levels, the sulfur-containing species will be converted to sulfur oxides (SO_x) when the gas is burned. Wet scrubbers are commercially available for SO_x removal and are well proven commercially. Because the scrubbing adds additional capital and operating costs, the use of high-sulfur biomass feedstocks will be limited to those situations where waste disposal is necessary.

For synthesis gas applications, however, sulfur concentrations are limited to about 0.1 mg/ Nm^3 (Graham and Bain, 1993). Fuel cell systems will also require sulfur concentrations of less than 1 ppm. Sulfur containing species poison catalysts used for chemical synthesis, particularly copper-based ones such as those used in methanol synthesis. Technologies for

sulfur removal are commercially available and have been used successfully in coal gasification/synthesis processes for many years. In most coal gasification systems, sulfur is removed using low temperature processes. Carbonyl sulfides are catalytically converted to hydrogen sulfide at modest temperatures, and the product gas is then further cooled to below 100 °C when water condenses. Hydrogen sulfide is recovered using technologies such as a Claus sulfur recovery process.

Research and development activities have also been conducted on higher-temperature sulfur recovery processes in coal-based systems. In the higher-temperature processes, sulfur-containing species are removed from the gas stream by absorption onto metal oxide pellets at about 480° C. The metal oxide pellets are in a moving bed reactor and are regenerated externally. The high temperature process has been shown to be feasible in demonstration scale experiments, and the technology has been installed to clean a slipstream of the gas in a 250 MW_e coal fired electricity generating plant in Tampa, Florida (U.S. Department of Energy, 1996b). While operational difficulties with the hot cleanup technology have been encountered, commercial development of the process is ongoing.

The same types of sulfur removal technologies would also be potentially suitable for biomass gasification/synthesis gas systems. Economic rather than technical feasibility remains the largest uncertainty barrier to sulfur removal from biomass gasification products. The low levels of sulfur in biomass systems using clean woody feedstocks may provide other options for removing sulfur from the synthesis gas stream. Sulfided Co/Mo catalysts can be used to crack hydrocarbons in the gas stream, as described below. These catalysts could adsorb sulfur while retaining activity. Additional research and development of this approach is needed to evaluate its technical feasibility.

3.3.6 Hydrocarbon reduction and gas conditioning for producing synthesis gases and hydrogen

Production of liquid fuels and chemicals from synthesis gases require a very clean gas composed almost exclusively of carbon monoxide and hydrogen. Low molecular weight constituents such as methane and ethane also serve as inert diluents that further reduce the efficiency of converting the gas into final products. Higher molecular weight hydrocarbons such as hexanes or benzene may also react with and deactivate synthesis catalysts through carbon deposition and other mechanisms. Fuel cells also have related gas quality requirements as described in Section 4.

The processes for converting hydrocarbons to additional synthesis gas are commercially mature. Methanol, for example, is currently produced by the catalytic cracking and steam reforming of natural gas or petroleum. The synthesis gas, with a H₂/CO ratio of about 2.1:1, is then converted to methanol using Cu/Zn catalysts at 350–400 °C. Methanol and Fischer-Tropsch liquids have also been produced in large quantities using coal as a feedstock to produce the intermediate synthesis gas. In the coal case, the feedstock is gasified with oxygen to produce a medium-energy synthesis gas, the gas is cooled and scrubbed, and the intermediate product is catalytically reformed to reduce hydrocarbons and adjust the H₂/CO ratio.

Production of liquid fuels and chemicals from the medium-energy biomass gas would be similar to that for coal. Following tar and particulate removal from the raw medium-energy gas, hydrocarbons would be cracked at 700–900 °C. Catalysts such as sulfided Co/Mo that can tolerate the low levels of sulfur in the biomass product might be used to eliminate the

need for a separate sulfur-removal step. Since raw biomass gases are generally deficient in hydrogen, water shift gas reactions would adjust the H₂/CO ratio. Following scrubbing to remove CO₂ and acid gases, the final synthesis gas would be converted using commercial technologies.

Experimental data has also been collected for biomass systems. In bench-scale tests using commercial nickel-based catalysts, it has been reported (Berg, et al, 1997) that steam reforming over nickel catalysts can potentially be effective even in the presence of some sulfur-containing species. In these tests, hydrogen sulfide present at levels of 100 and 200 ppm partially deactivated the catalyst, but activity could be retained in part by increasing the reaction temperature.

Related work on steam reforming of biomass gas for production of hydrogen has been reported (Czernik, et al, 2000; 1999). Pyrolysis products similar to tars from biomass gasifiers were vaporized and reacted with steam over a nickel-based catalyst (U91) used commercially in the reforming of natural gas. In bench-scale experiments, yields approached 80% of the theoretical value with some carbon formation on the catalyst surface. In biomass gasification systems, the amounts of tar would be significantly lower than in the reported system, which had different goals. However, the work suggests that shifting the biomass gas and dealing with residual amounts of tar in the product gas is potentially feasible using commercial catalysts.

Recent interest has also been expressed in the use of biomass thermal gasification to provide a hydrogen-rich fuel gas for fuel cells (see, for example, Amos, 1998). The issues of gas cleanup are closely related to those of producing a synthesis quality product. Removal of particulates and tar from the gas stream is essential, and reforming of the gas is also required. Care must also be exercised to ensure low sulfur content in the fuel gas. The overall compatibility of the gasification and fuel cell technologies has not been well characterized, but the gas cleanup demands of the fuel cells will likely be similar in magnitude to those for synthesis gases. Fuel cell requirements are discussed more in Section 4 of this report.

While the production of fuels and chemicals from biomass synthesis gases is technically feasible, the economic feasibility is more difficult. The subject of integrated biomass gasification systems for synthesis gas and for hydrogen production with fuel cells is discussed in more detail in Section 4 of this report.

3.4 Survey of Biomass Gas Conditioning Technologies

As part of the ongoing IEA Bioenergy Agreement Task on biomass gasification (IEA Bioenergy, 2000), a survey of technologies available for biomass gas conditioning was developed in 1999. The survey was developed for participants to distribute to industries in their own countries. The responses were to be used to develop a listing of available technologies and the companies capable of providing them. As the IEA Bioenergy Task proceeded, it was decided that a world-wide compilation of the capabilities of individual companies was lower priority than other efforts, and the survey was not widely distributed. The survey developed through that effort is attached to this document as Appendix A and can freely be distributed if individuals wish to compile a directory of capabilities for their own country.

4. INTEGRATED GASIFICATION/END-USE SYSTEMS

For biomass gasification systems to be successful, the gasifier, the accompanying gas conditioning technologies, and the end-use application must be carefully designed as an integrated unit. The end-use application will determine the gas “quality” requirements, with some applications such as kilns being less demanding while others such as gas turbines or fuel cells being more demanding. Many individual gas conditioning technologies are available to meet these requirements, but each has operational and economic implications that will affect overall performance. In addition, different gasifiers produce raw fuel gases with different characteristics. As a result, it is essential to design integrated systems that can both operationally and economically meet end-use requirements.

In the following section of this report, several large-scale biomass gasification systems are summarized that are either in current operation or are in the design and construction stage of development. The discussion provides an overview of the current strategies being used for gas conditioning in large-scale systems and highlights situations where opportunities for improvements in next-generation systems may exist. It should be noted that the discussion of facilities is not intended to be a comprehensive listing of all current efforts but is intended instead to highlight the range of different gas conditioning approaches being taken at present.

Four types of gas conditioning approaches are discussed based on the demands of the end-use system and the approach taken to clean the product:

- Systems requiring minimal hot-gas conditioning that produce fuel gases for relatively undemanding end-use applications
- Systems requiring significant gas conditioning that produce cool (<100 °C) fuel gases for demanding applications
- Systems requiring significant gas conditioning that produce warm or hot (>100 °C) fuel gases for demanding applications
- Systems requiring exceptional gas conditioning that produce synthesis gases for the manufacture of fuels and chemicals, or hydrogen for fuel cells

Specific gasifier facilities are discussed below. The selection of gasification facilities for discussion is not intended to be a complete listing of all such facilities but is intended to illustrate the variety of approaches that are currently being taken with larger-scale gasification systems. More complete listings of active biomass gasification facilities are available elsewhere (BTG, 2000; Reed, 1999). The gasification systems that will be described are summarized in Table 4.1. At present, there are no stand-alone biomass synthesis gas facilities, but this topic is discussed in more detail in Section 4.4.

Table 4.1. Representative large-scale gasification projects

Facility	Capacity	Gasifier type	Pressurized (y/n)	Heating value of gas MJ/Nm ³	End-Use Application	Status Mid 2000
Fuel Gases with Minimal Gas Conditioning						
Lahti Gasifier, Finland	50 MWt	Circulating fluidized bed	N	2.2	Gas co-fired in coal-fired steam cycle power generation station	In full commercial operation for more than a year
Primenergy Gasifier, Stuttgart, Arkansas	6 - 12 MWe	Three Fixed bed updraft gasifiers	N	~5	Fired in a steam-cycle boiler for power generation	In full commercial operation since early 1997
Cool Fuel Gas with Significant Gas Conditioning						
Amergas, Netherlands	85 MWt	EPZ/Lurgi air-blown fluidized bed	N	~5	Gas co-fired in coal-fired steam cycle power generation station	Construction complete; facility undergoing shakedown operation
ARBRE, United Kingdom	8 MWe	TPS air-blown fluidized bed	N	5.4	ALSTOM Typhoon gas turbine	Construction nearing completion
Vermont Gasifier Project, Burlington VT	5 MWe	FERCO/Battelle Indirectly heated, circulating bed	N	16.5 - 18.5	Gas turbine use intended, fuel gas for steam-cycle power station in initial phase.	Gasifier testing underway
Warm or Hot Fuel Gases with Significant Gas Conditioning						
Värnamo, Sweden	6 MWe	Sydskraft air-blown, circ. fluidized bed	Y	5	ALSTOM Typhoon gas turbine	Demonstration project terminated in 2000 following successful operation in IGCC mode

4.1 Fuel Gases for Systems With Minimal Gas Conditioning Requirements

4.1.1 Overall Gas Conditioning Strategy – Minimal Gas Conditioning

Some end-use technologies require only minimal cleanup and conditioning of the raw product gas. In these systems, the gases are combusted in burners to provide heat for system needs. Examples could include biomass-fired kilns, steam-cycle power generation systems, or cofiring applications where biomass fuel gases are burned in coal power stations. These systems have several common characteristics that allow the minimally treated gas to be used effectively:

- The end-use can tolerate significant amounts of particulates
- The system has no special sensitivities to alkali salts
- The gasifier and end-use technology are closely coupled, which helps retain the sensible heat in the raw gas and also prevents tar condensation in pipes
- Tars are combusted at the burners
- Environmental emissions regulations can be met by treating the cool combustion gases after the heat is extracted, or emissions requirements are minimal

In uses of this type, the overall gas conditioning strategy is to burn the gas following minimal treatment of the raw product. Bulk particulate removal is accomplished using a cyclone filter, and in some cases heat may be recovered by a heat exchanger for other uses. The gas is kept hot or warm (>200 °C) to both retain the energy in the product gas and to prevent tar condensation. The product gas, including tars and hydrocarbons in the product stream, is burned in closely coupled burners. Fly ash, NO_x, SO_x, and other emissions are controlled by the use of conventional technologies that treat the combustion flue gases. The approach lowers capital and operating costs because the gas conditioning technology is minimal, but the resulting fuel product can only be used in relatively undemanding end-uses.

Examples of such systems include the biomass gasifiers in Lahti, Finland, and the Primenergy gasifier in Stuttgart, Arkansas. These gasification systems are discussed in more detail below to illustrate the implications for this approach to gas conditioning. Other gasification facilities with similar gas conditioning requirements exist elsewhere. These facilities were selected for discussion because they are representative of newer, large-scale biomass installations for this type of application.

4.1.2 Example of a Gasification System Requiring Minimal Gas Conditioning: Lahti, Finland

4.1.2.1 System Description

The Lahti gasifier converts wood and other wastes to a low-energy fuel gas that is cofired in an existing coal-fired, steam-cycle power station (Foster Wheeler, 1999). The power station was built in the mid-1980s and produces both electricity and hot water for district heating. Electricity and heat production capacities are 167 MW_e and 240 MW_t respectively. The gasification unit was added in 1997 to demonstrate the commercial feasibility of using wood and biomass wastes as fuels for power generation. The intent of the effort was to allow the

power station to operate at full power with lower CO₂ and NO_x emissions than would be obtained operating on coal alone. The gasifier contributes up to about 50 MW_t of the energy for power generation.

The gasifier is an air-blown, circulating fluidized bed design that operates at atmospheric pressure. It was designed to accept biomass fuels with up to 60% moisture content without the need for drying. This feature allows a variety of biomass feedstocks to be used and reduces costs for feedstock drying. The high moisture content of the feedstock, however, results in a wet fuel gas with a low energy content. When operating with wood residues at 50% moisture content, the energy content of the product gas is about 2.2 MJ/Nm³. While tar concentrations in the product gas have not been reported, they are probably high. Other feedstocks such as shredded tires and waste-derived fuels have also been tested. The internal gasifier temperature is about 850 °C. The hot fuel gas passes through a heat exchanger that cools the product to about 450 °C and simultaneously heats the combustion air. Heating of the combustion air is necessary to ensure adequate gasification of the undried biomass. The warm, low-energy fuel gas is transferred directly to burners in the coal-fired unit. The burners were specially designed to allow for reliable combustion of the very low energy content fuel gas.

The hot gases produced by cofiring the fuel gas with coal pass through a single-pass boiler where they are cooled, and fly ash is removed with electrostatic precipitators. The power station uses only low-sulfur coal and is not equipped with SO_x removal technology. The emission of NO_x is controlled by flue gas circulation and staged combustion. The temperature profile of the integrated system is shown in Figure 4.1.

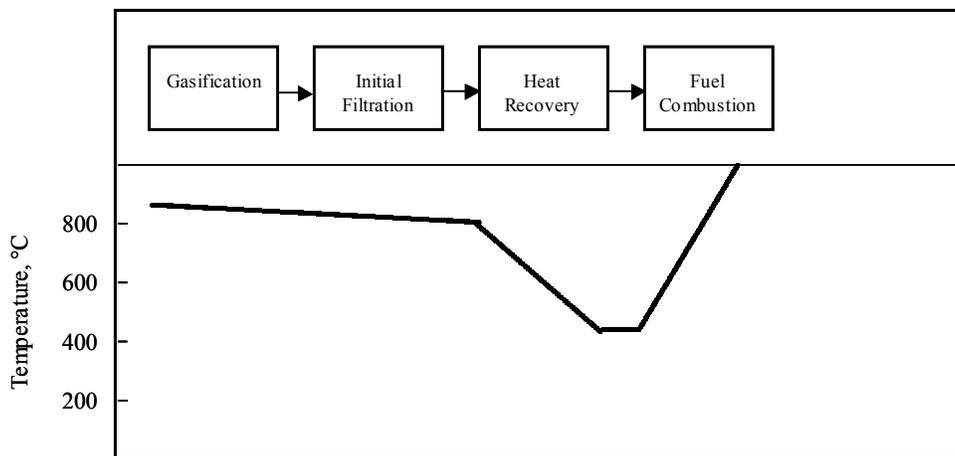


Figure 4.1. Temperature Profile of Lahti Gasification System

4.1.2.2 Gas Conditioning

Conditioning of the raw biomass fuel gas from the Lahti system is minimal. Bulk particulates are removed by a cyclone that separates the flowing bed material from the product gas and returns the bed material to the gasifier. Bottom ash is periodically removed from the bottom of the gasifier. The biomass fuel burners are insensitive to fly ash, and so recovery of the biomass fly ash is accomplished after the boiler, by the same precipitators used for removing coal fly ash.

Part of the heat from the fuel gas is recovered by a heat exchanger that is used to preheat the combustion air. The heat recovery step is dictated by the need to provide extra heat to gasify the moist biomass rather than requirements of the combustor. The “warm” product flows directly to the burners where it is consumed. The use of the warm product gas both prevents tar condensation in the closely coupled system and retains part of the sensible heat to improve conversion efficiencies. This is particularly important in a system where moist biomass feedstocks are used.

4.1.2.3 Operational Experience and Implications

The gasifier at the Kymijärvi Power station in Lahti has operated successfully for about two years. In the first year, about 230 GWh of energy were produced in over 4700 hours of operation. Operating availability has exceeded 90% after initial shakedown, and the facility has used a variety of feedstocks including uncontaminated wood residues, railroad ties, refuse-derived fuels, and shredded tires. Cofiring of the biomass-derived gas with coal reduces particulate, NO_x, and SO_x emissions as compared to combustion of coal alone. The integrated system with minimal gas conditioning appears to work as planned.

Despite the minimal product gas conditioning, the system taken in its entirety deals with the constituents in the biomass product. The strategies for dealing with various raw gas constituents are summarized in Table 4.2.

Table 4.2. Gas conditioning systems requiring minimal gas conditioning. Example: Lahti gasifier where product gas is cofired with coal in a steam-cycle power station.

Constituent	Requirement for Specified Application	Strategy and Comments
Particulates	Removal of bulk material >10 μm	Bulk particulates are removed by the bed recirculation cyclone. Fly ash from both coal and biomass is removed following combustion using electrostatic precipitators. Cofiring results in net particulate reductions of $\sim 15 \text{ mg/Nm}^3$.
Alkali	Not defined	Ash deposition behavior in the cofired system is the same as that for coal alone
Tars	Prevent condensation; quantity of tars unimportant	Tars formed during gasification are combusted in the burner. The gasification and combustion facilities are located in close proximity, and pipelines are insulated to prevent tar condensation. This approach allows part of the sensible heat in the product gas to be used efficiently.
Ammonia and NO_x	Final NO_x emissions <240 mg/MJ^*	Due to lower combustion temperatures of the very low-energy biomass gas and the presence of ammonia in the raw product, the NO_x emissions from the co-fired facility are 5 to 10 % less than those from coal alone.
Sulfur-containing Species	Final SO_x emissions <240 mg/MJ^*	No special sulfur-removal technologies are used. The facility uses low-sulfur coal, and the cofiring of biomass further reduces the SO_x concentrations.
Hydrocarbons	No limit	Hydrocarbons are desirable since they increase the energy content of the gas

*Local environmental regulation

The gas conditioning systems provide an economical way to provide fuel gas to this facility. Operational experience suggests the gas cleanup technology is reliable. While the gas from this system would not be suitable for use in high-demand technologies, it fully meets the requirements of the selected end-use.

4.1.3 Example of a Gasification System Requiring Minimal Gas Conditioning: Primenergy, Stuttgart Arkansas

4.1.3.1 System Description

The Primenergy facility in Stuttgart, Arkansas (USA), converts rice hulls to a fuel gas that is burned to provide steam for power generation (Primenergy, 2000). The facility was completed in 1996 and began commercial operation in early 1997. The facility converts about 500 tons/day of biomass and has a capacity of about 12 MW_e . In practice, the facility typically produces a combination of about 6 MW_e plus high-pressure steam for an adjacent food processing facility.

The gasification facility consists of three fixed-bed, updraft gasifiers. The gasifiers are air-blown units operating at near-atmospheric pressures and produce a typical low-energy gas with an energy content of about 5 MJ/Nm³. This is the only facility discussed in this section that uses fixed-bed gasification technology. The fixed-bed gasifier configuration was chosen in part because it can handle the rice hull feedstock. As discussed previously, fixed-bed gasifiers have size limitations. To achieve the total energy output required, the three gasifiers operate simultaneously to provide the total quantity of fuel gas used by the steam boilers.

The raw product gas exits the reactor at about 700 °C and is transferred to a closely-coupled boiler. The gas contains significant concentrations of tars (characteristic of updraft gasification systems) and the temperature is maintained to prevent tar condensation. The raw fuel gas is then burned in a staged combustion system. Following steam production in the boiler, the cooled combustion gases pass through bag filters where fly ash is collected. The temperature profile of the integrated system is shown in Figure 4.2.

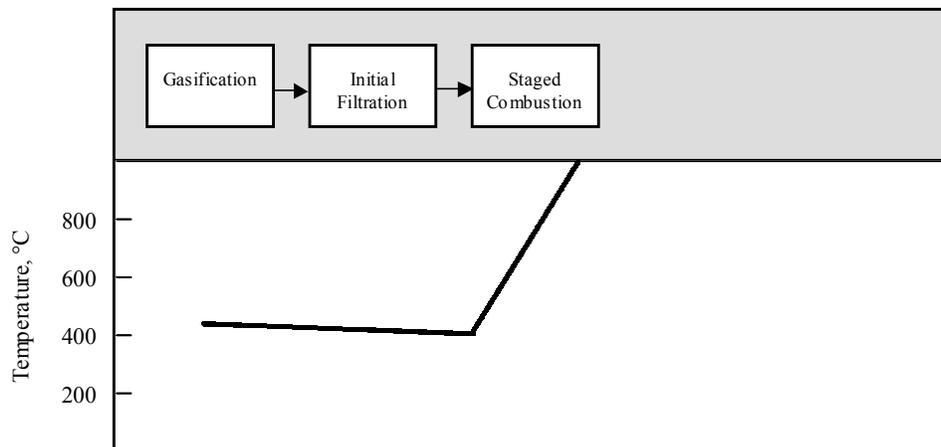


Figure 4.2. Temperature Profile of Primenergy Gasification System

4.1.3.2 Gas Conditioning

Gas conditioning in this system is minimal. Raw, hot gases pass directly from the gasifier into a staged combustor, and transfer pipes are insulated to prevent tar condensation. The staged combustion system provides for sequential addition of combustion air, which allows tars to be fully consumed and also provides for control of NO_x.

Particulates from the gasification process also pass into the combustion system. Rice hulls, as described in Section 2, have high ash contents. In the Primenergy system, about 3% of the inorganic material in the feedstock passes from the gasifier in the form of fly ash. The remainder is extracted from the gasifier beds periodically. No particular problems have been experienced with ash deposition in the boiler system. The fly ash is collected after the boiler using bag filters. The strategies for dealing with various raw gas constituents are summarized in Table 4.3.

Table 4.3. Gas conditioning systems requiring minimal gas conditioning. Example: Primenergy gasifier where product gas is used for steam-cycle power generation.

Constituent	Requirement for Specified Application	Strategy and Comments
Particulates	Minimal requirements	Updraft gasifier produces particulate levels that are tolerated by the combustion system. Fly ash is removed from the combustion gases after the boiler using bag filters.
Alkali	Not defined	Ash deposition has not been a problem in this system .
Tars	Prevent condensation; quantity of tars unimportant	Tars formed during gasification are combusted in the staged combustion system. The gasification and combustion facilities are located in close proximity, and pipelines are insulated to prevent tar condensation. This approach allows the sensible heat in the product gas to be used efficiently.
Ammonia and NO _x	Final NO _x emissions limited by regulation	NO _x emissions are controlled through the use of a staged combustion process.
Sulfur-containing Species	Final SO _x emissions	No special sulfur-removal technologies are used because the rice hull feedstock is low in sulfur.
Hydrocarbons	No limit	Hydrocarbons are desirable since they increase the energy content of the gas.

4.1.3.3 Operational Experience and Implications

The Primenergy facility in Arkansas was completed in late 1996 and underwent shakedown operation in early 1997. The operators report that the facility has successfully operated at about 95% online availability since then. The integrated system with minimum gas cleaning is operating as planned.

4.2 Cool Fuel Gases for Systems With Significant Gas Conditioning Requirements

Other large-scale end-use technologies require more significant gas conditioning prior to use. The fuel gases in these systems are used with gas turbines or gas engines for power generation. In some cases, environmental considerations may also require significant gas conditioning in systems producing fuel gases for conventional steam-cycle heat and power generation. The need for more extensive gas conditioning is dictated by the requirements of the end-use and may include some or all of the following considerations:

- The end-use is intolerant to particulates.
- The system has sensitivities to deposition of vaporized alkali salts.

- The gasifier and end-use technology are not closely coupled, and tar condensation would cause plugging in pipes.
- Tars could collect in compressors or engine parts and create operational problems.
- Environmental emissions regulations require significant gas conditioning.

Cool fuel gases are required for thermodynamic and efficiency reasons for some systems including those with compressors or those with internal combustion piston engines. However, the gas cooling also results in a loss of the sensible heat in the product gas. While part of the heat of the raw product gas can be recovered using heat exchangers, there is inevitable heat loss as the gas is cooled, and this loss can result in lower overall thermal efficiencies. As a result, this general approach is best suited to those systems where cool gases are required by the end-use or some heat loss can be tolerated. Production of cool gases also allows wet scrubbing systems to be used, which provides additional opportunities to produce a clean fuel gas.

At present, most large-scale biomass gasification systems are being designed with gas conditioning technologies that produce a cool (<100 °C) fuel gas. In these systems, the gas is sequentially cooled, and unwanted constituents such as particulates or tar aerosols are typically removed using wet scrubbing methods such as scrubbers or wet electrostatic precipitators. Wet scrubbers operate through the contact of particulates and tars with water droplets and require that the system operate at temperatures lower than the boiling point of water. These wet scrubbing methods are the most commercially mature technologies for conditioning the raw product gas and provide for effective gas cleaning.

4.2.1 Overall Gas Conditioning Strategy – Producing Clean, Cool Fuel Gases

Biomass systems that produce clean, cool product gases sequentially cool the gas and remove particulates, tars, and other constituents with appropriate technologies. Particulate and tar removal steps are conducted separately to prevent condensation of sticky tar material on the filter cake. A wide variety of particulate filter systems can be used including barrier filters, bag filters, and others depending on the temperature of the product stream. Tars can either be removed physically at low temperatures following particulate removal or catalytically at high temperatures prior to gas cool-down and particulate removal. Remaining particulates, tars, and other constituents are then removed at low temperature by wet scrubbing systems. The wet scrubbing systems remove these materials from the gas stream through contact with liquid droplets and cool the gas to below the boiling point. In most systems, the gas is produced at about 35 °C.

Three systems are discussed below to illustrate current approaches that produce clean, cool fuel gases. These examples include the Amergas facility in The Netherlands where clean fuel gas from urban wood waste is co-fired in a coal power station; the ARBRE facility in the United Kingdom where the fuel gas will be fired in a gas turbine; and the Vermont Gasifier Project in Burlington, Vermont where the gas will be used for CHP power generation with a gas turbine. As stated previously, these are not a complete list of all gasifiers systems of this kind but were chosen to illustrate a variety of approaches to gas conditioning.

4.2.2 Example of a Gasification System Producing Cool, Conditioned Gas: Amergas Facility in Geertruidenberg, Netherlands

4.2.2.1 Project Overview

The Amergas gasifier converts demolition and other wood wastes into a low-energy fuel gas that is cofired in an existing coal-fired, steam-cycle power station (EPZ, 1999). The Amer Power Station, located in Geertruidenberg, The Netherlands, burns coal to produce steam for power generation and heat. The gasifier facility was recently added to the power station to reduce net carbon dioxide emissions from the facility and to reduce urban wood wastes. To meet local environmental regulations and to avoid possible controversy over the use of urban wood wastes, the developers chose to extensively clean and condition the fuel gas prior to its use. The resulting fuel gas should readily meet the requirements for cofiring it with coal, and it should also be suitable for other uses requiring a very clean fuel gas. While the end-use for the fuel gas is the same as the Lahti gasifier described above, the gas conditioning approach is very different.

The Amergas facility uses a circulating fluidized bed gasifier with a capacity of about 85 MW_t. The gasifier is designed to consume about 150,000 tons/year of urban wood wastes consisting of material that is not impregnated but may have other contamination. The gasifier was constructed in 1999, and shakedown operation started in 2000.

The gasifier is an air-blown, CFB design that operates at near-atmospheric pressure. The bed material is composed of sand, and limestone may also be added in later tests. Chipped wood is gasified in the fluidized bed at 850-900 °C. As with most CFB designs, raw product gas is separated from the entrained bed material, unconverted carbon, and bulk particulates using a cyclone.

The raw gas is then cooled to 200–240 °C using a heat exchanger that heats water and produces steam used in the power station. The product gas passes through bag filters to remove particulates. The gas then passes through wet scrubbers that remove tars and cool the gas to about 35 °C. Finally, additional wet scrubbing is used to remove ammonia from the product. Recovered ammonia is re-injected into the gasifier where it is partly destroyed through thermal equilibrium and reaction with NO_x. The conditioned fuel gas with an energy content of about 5 MJ/Nm³ is then piped to the power station where it is burned. The temperature profile of this system is shown in Figure 4.3.

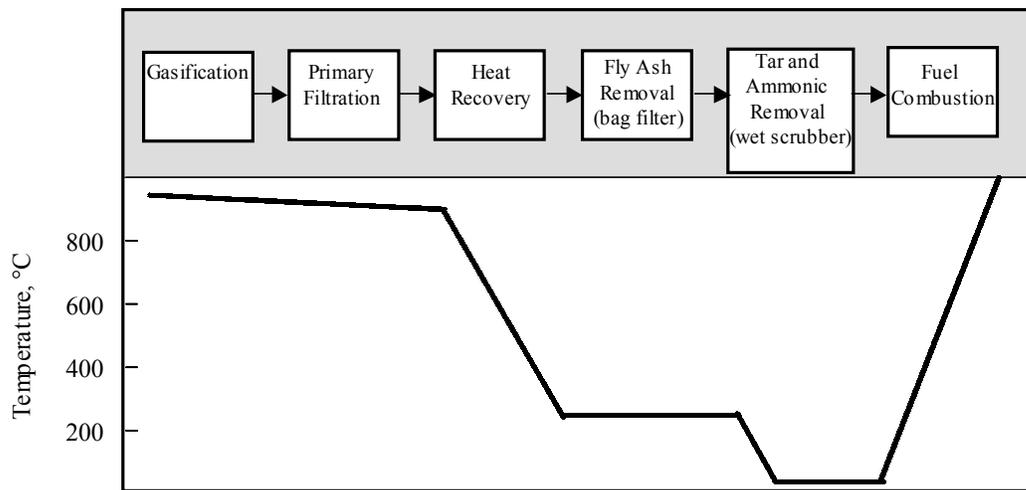


Figure 4.3. Temperature Profile of Amergas Gasification System

4.2.2.2 Gas Conditioning Strategy

The overall strategy for the Amergas facility is to produce a very clean gas that both meets all environmental emissions requirements and avoids controversy over the use of urban wood waste feedstocks. To do so, the gas is cooled and thoroughly scrubbed to remove particulates, tars, and ammonia. Significant amounts of heat are extracted from hot gas stream using a heat exchanger to produce steam, but some heat loss and resulting system inefficiency is inevitable with the scrubbing systems involved. In this system, the need for thorough gas conditioning is a higher priority than heat retention. This contrasts markedly with the Lahti facility described above where the fuel gas is used with minimal conditioning in a similar co-firing application.

In this system, the gas is sequentially cooled to selectively remove various constituents. At the exit of the first heat exchanger, the gas is 200–240 °C. This temperature is cool enough to allow the use of bag filters for fly ash removal, but high enough to prevent tar condensation that would otherwise result in the buildup of sticky material on the bag surface. Tar removal is subsequently accomplished by wet scrubbing, which further cools the gas to about 35 °C. Tar will be partially removed from the scrubber water by settling, and the resulting oil emulsion will be reinjected into the gasifier. Following tar removal, the cool gas is further scrubbed to remove ammonia, which is recovered and reinjected into the gasifier. In the gasifier, ammonia is mostly destroyed through reactions with NO_x and through thermal equilibrium reactions. Excess wastewater is injected into the coal combustor for destruction of remaining components.

By dealing with each of the product constituents sequentially, this approach is designed to produce a cool fuel gas that can potentially be used for many applications. The gas conditioning strategy is summarized Table 4.4.

**Table 4.4. Gas conditioning in systems requiring significant gas conditioning.
Example: Amergas facility in Netherlands**

Constituent	Requirement for Specified Application	Strategy and Comments
Particulates	Removal of bulk material	Bulk particulates are removed by the bed recirculation cyclone.
	Removal of fly ash	Fly ash removed by bag filters at ~200 °C, above the temperature of tar condensation.
Alkali	Not defined	In the cofired application, any effects of alkali from biomass are likely to be minimal.
Tars	Prevent condensation; quantity of tars unimportant	Tars formed during gasification are collected by wet scrubbing after particulates have been removed from the gas stream. The resulting oil emulsion is injected into the gasifier for destruction.
Ammonia and NO _x	Dependent on coal-fired facility	Ammonia is removed from the product gas by wet scrubbing. Recovered ammonia is reinjected into the gasifier where it is destroyed by thermal equilibrium. Ammonia reinjection also destroys NO _x that may be present.
Sulfur-containing Species	Final SO _x emissions dependent on coal sulfur concentrations and flue gas scrubbers	No special sulfur-removal technologies are used, and the wood waste is typically low in sulfur. Wet scrubbing removes most SO _x .
Hydrocarbons	No limit	Hydrocarbons are desirable since they increase the energy content of the gas.

4.2.2.3 Operational Experience and Implications

The gasifier at the Amer Power Station was completed in early 2000, and shakedown operation of the facility has begun. As a result, operational data from the facility is not yet available.

The extensive gas conditioning achieved in this facility appears to be driven by environmental considerations including the need to produce a very clean gas and to reduce net CO₂ emissions from the coal-burning power station. The gas conditioning equipment adds capital and operating costs to the system compared to the simpler system used in Lahti, Finland. The use of such clean fuel gases for relatively undemanding applications is most likely in situations with similar environmental demands. As a fully commercial demonstration of this technology, however, this system should provide valuable data on producing clean gases that could be used in more demanding applications such as gas turbines.

4.2.3 Example of a Gasification System Producing Cool, Conditioned Gas: ARBRE Facility in The United Kingdom

4.2.3.1 *Project Overview*

The ARBRE project is intended to be an integrated bioenergy demonstration that will use wood from short-rotation plantations to fuel a biomass gasification/gas turbine combined cycle power generation facility. Planned net electrical output is about 8 MW_e. The long-term goal of the ARBRE project is to demonstrate that power can be generated from dedicated short-rotation wood crops in The United Kingdom (ARBRE, 1999; Rensfelt, 1998; Ritcher, et al, 1988; Pitcher, et al, 1997). The project is a joint effort between Yorkshire Water plc, which generates and distributes power, TPS of Sweden, a developer of biomass gasification technology, and Royal Schelde Group of The Netherlands, which will construct and operate the plant. Construction of the ARBRE project began in 1998.

Initially, the plant will be powered by wood from a combination of conventional forestry and short-rotation plantation sites. The proportion of feedstock from short-rotation forestry is expected to increase over time with approximately 1000 ha of arable land to be used for short-rotation *Salix* (willow) production. Productivity is expected to be about 9–12 ODT/ha/year with harvesting on a 3-year basis.

The gasifier for the facility will be an atmospheric pressure, air-blown circulating fluidized bed system developed by TPS of Sweden. Like other air-blown systems, air is both the fluidizing medium for the bed and an oxidant to promote the gasification reactions. The gasifier will operate at temperatures of 850–900 °C, and the product gas will have an energy content of about 5.4 MJ/Nm³, typical of air-blown gasifiers.

Gas conditioning is accomplished using sequential filtration and scrubbing. Bulk particulates are removed from the hot raw gas using a cyclone, and tars are then cracked while the gas is still hot. The gas is then passed through a heat exchanger to recover heat that is used for generating steam. The warm gas is then passed through bag filters to remove remaining particulates, and the product then passes through a wet scrubber for final conditioning.

The clean, cool, conditioned gas will be split into two streams, one to provide fuel for both the gas turbine and one to a boiler to raise steam for the steam turbine. Fuel gas for the gas turbine will be compressed mechanically and injected into a Typhoon industrial turbine. A steam turbine in a combined cycle configuration will produce another 5.25 MW of electricity. The heat for generating the steam will be provided by several sources including recovery from the gas cooler, recovery from the turbine exhaust, and combustion of part of the product gas in a boiler. The facility will use approximately 2 MW_e for internal needs, leaving a net 8 MW of electricity for export to the grid. ARBRE calculates the overall efficiency of the combined cycle system of about 31%. The temperature profile of this system is shown in Figure 4.4.

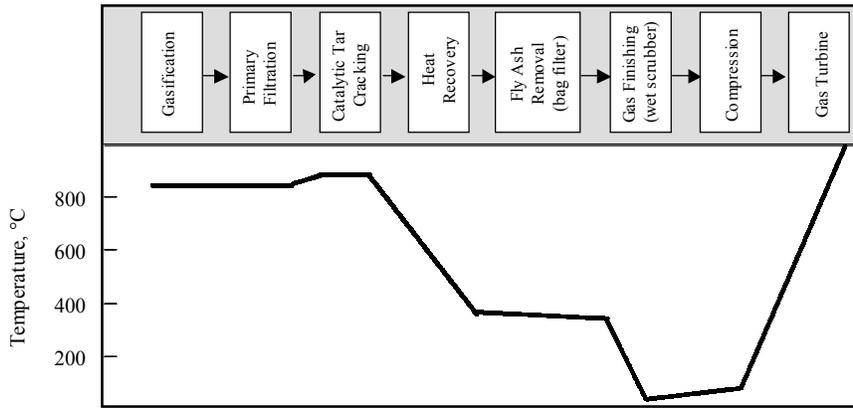


Figure 4.4 Temperature Profile of ARBRE Gasification System

4.2.3.2 Gas Conditioning Strategy

The gas conditioning strategy for the ARBRE project is to produce a gas suitable for gas turbine use, with particular attention paid to both particulate material and tars. The reported limits for particulate loadings vary significantly but are dependent on the size distribution of the material. Typical gas turbine limits for particulates are shown in Table 4.5. In all cases, however, alkali concentrations are strictly limited to 0.1 to 0.2 mg/Nm³.

Table 4.5. Particulate loading limits for gas turbines

Particulate size	Loading limits, mg/Nm ³
> 20 µm	< 0.1
10 - 20 µm	1.2
5 - 10 µm	10 - 15
< 5 µm	40 - 100

In the ARBRE system, bulk particulates will be removed from the circulating bed material using a cyclone filter. Following hot catalytic tar cracking and heat recovery, the warm gas (about 350 °C) will undergo further particulate removal using bag filters. Final particulate removal is accomplished by the use of a wet scrubber that also removes ammonia from the product gas. The use of the sequential filtration systems is expected to reduce overall particulate loadings and the concentrations of alkali salts to below the gas turbine inlet requirements.

Tars will be destroyed in their hot, vaporized state prior to particulate removal by the use of a catalytic tar cracker. The cracker uses dolomite as the catalyst. While the gas turbine can tolerate moderate amounts of tars, tar destruction is critical in this atmospheric-pressure system because the gas is mechanically compressed prior to its use. The catalytic cracking process removes most tars, prevents problems of downstream tar condensation, and significantly reduces the amounts of tars collected by the wet scrubber. The use of the catalytic cracker is significantly different than the approach for the Amergas facility where tars are collected solely by wet scrubbing and then reinjected to the gasifier.

The final stage of the ARBRE gas conditioning system is a wet-scrubber system with dilute sulfuric acid. The scrubber “finishes” the gas conditioning by removing additional

particulates, tars, and ammonia. The cool, clean gas will then be compressed and used to fuel the gas turbine. The gas conditioning strategy is summarized in Table 4.6.

Table 4.6. Gas conditioning in systems requiring significant gas conditioning. Example: ARBRE facility in The United Kingdom. Gasification/gas turbine cogeneration facility

Constituent	Requirement for Specified Application	Strategy and Comments
Particulates	Requirement: 1.2 mg/Nm ³ for particulates of 10-20 μm (see table 4.5)	Bulk particulates are removed by the bed recirculation cyclone. Fine particulates and fly ash are removed by bag filters at ~350 °C following hot catalytic tar cracking. Final particulate removal is accomplished using a wet scrubber.
Alkali	< 0.1 – 0.2 mg/Nm ³	Gas cooling and sequential particulate removal allow condensation of alkali vapors and subsequent collection of entrained solids as particulate material.
Tars	Preference of < 50 mg/Nm ³ to prevent compressor problems	Tars formed during gasification are catalytically destroyed at ~800 °C using dolomite as a catalyst to destroy tars. Following gas cool down, wet scrubbing removes remaining material.
Ammonia and NO _x	Ammonia removal important to limit NO _x formation in turbine exhaust gas.	The final wet scrubbing with dilute acid removes ammonia.
Sulfur-containing Species	Final SO _x emissions dependent on local regulations	Facility will use low-sulfur short-rotation species as feedstocks; no additional removal necessary .
Hydrocarbons	No limit	Hydrocarbons are tolerated since they increase the energy content of the gas

4.2.3.3 Operational Experience and Implications

The ARBRE gasifier is currently being constructed and operational data is not yet available. The gasifier and gas cleanup portion of the project is based on technology developed by TPS Thermiska Processor of Sweden. Since the late 1980s, TPS has operated various gasifier systems and collected extensive data on hot-gas cleanup methods. TPS has a 2.5 MW gasifier at Studsvik that it has operated for more than 2000 hours, and tests with a gas cleanup system have shown that dolomite cracking can be successful. TPS also has other related air-blown gasifiers and is conducting ongoing research and development activities with these systems (Hallgren, 1997; IEA Bioenergy, 1997). Based on the data from the smaller system, the fuel gas product will meet the demanding requirements of the gas turbine application.

4.2.4 Example of a Gasification Systems Producing Cool, Conditioned Gas: Vermont Gasifier Project , Burlington, Vermont, USA

4.2.4.1 *System Description*

The Vermont Gasifier Project is intended to be a demonstration of a gasification/ gas turbine IGCC system (Paisley, 1997a, 1997b; Burlington Electric, 1997). The project is located on the site of the Joseph C. McNeil power generating station in Burlington Vermont, a 50 MW_e steam-cycle facility in operation for about 15 years. The project is a joint effort between the developer, Future Energy Resources Company (FERCO), the U.S. Department of Energy, and Burlington Electric, the power station operator. The project has been organized as a two-phase effort. The first phase consists of the construction and shakedown operation of a 200 tpd gasifier based on the FERCO/Battelle design. During the first phase of operation, product gases from the gasifier will be transferred to the Burlington facility and burned to provide additional heat for the steam generation facility with minimal gas conditioning. In the second phase of work, a gas turbine, anticipated to have a capacity of approximately 5-10 MW_e, will be added to the system and tested. The discussion below outlines the gas conditioning required for the integrated gasifier/ gas turbine system since this is a major goal of the effort.

The gasifier is an indirectly heated, two-vessel design which has been described in more detail elsewhere (Feldmann, et al, 1988, Paisley, 1997). The gasifier operates at near-atmospheric pressure and produces a medium-energy gas product (16.5-18.5 MJ/Nm³). As such, it is the only active large-scale gasification project that will produce a medium-energy fuel gas. Gasification occurs as the biomass is heated by contact with the hot, entrained bed material (sand) in the first vessel. The product gases are separated in a cyclone filter, and the unreacted char plus the cooled bed material is transferred to a second vessel where the char is burned. The bed material, now re-heated, is then transferred back to the first vessel to provide heat for gasification. The hot circulating sand serves both as a heat transfer medium and as an entraining medium for the system.

The hot gases exit the gasifier at about 800 °C. Bulk particulates, entrained bed material, and incompletely reacted biomass are separated from the gas stream with a cyclone filter. In the integrated gasifier/ gas turbine system, the gas will then pass through a catalytic tar cracker to destroy most tars. The tar cracker will be a fluidized-bed design, most likely with a proprietary catalyst designated DN34. This material is reported to be a disposable, non-metallic catalyst. Following tar reduction, the gas will pass through a heat exchanger to recover heat for producing steam used in the gasifier. The warm gases will then be filtered, probably using bag filters, and wet scrubbing will be used to remove remaining tars and particulates. The cool product will then be compressed and used to power a gas turbine. In the initial phase of testing without the gas turbine, the tar cracking step and the wet scrubbing are omitted, and the hot gas is burned in the conventional power station. The temperature profile of the anticipated system including gas turbine is shown in Figure 4.5.

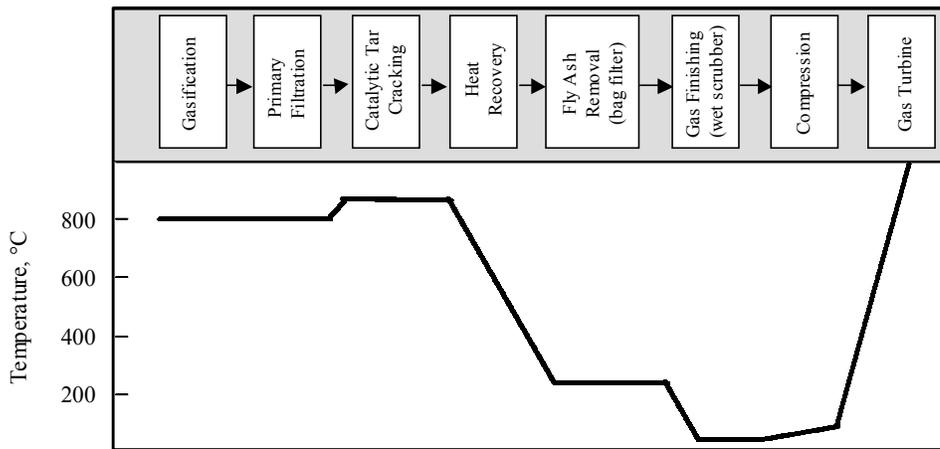


Figure 4.5 Temperature Profile of Planned Vermont Gasification System.

4.2.4.2 Gas Conditioning

The overall strategy for gas conditioning is guided by the need to remove particulates to meet gas turbine requirements and the need to reduce tars so that the gas can be mechanically compressed. Removal of both bulk particulates and most fly ash is accomplished by a cyclone downstream from the gasifier. Following tar cracking, final particulate removal will be accomplished by filtration (probably bag filters) followed by wet scrubbing.

It is anticipated that most tar removal will be accomplished by catalytic cracking prior to filtration and wet scrubbing. The tar cracking concept was tested in a smaller 10 tpd gasifier located in Columbus, Ohio, as described previously in Section 3.3.3.3 of this report. These tests produced a fuel to power a 200 kW_e Solar Spartan turbine. Tar removal using the catalyst at 800 °C reduced tar concentrations by about 90% (Paisley, 1997c). Using a wet scrubber after the catalytic cracking, tar levels were reported to be reduced to below detection levels, or “essentially zero” concentrations. Tests at the Burlington facility are expected to determine the effectiveness of this approach at large scale.

The production of sulfur oxides is controlled by the use of clean feedstocks consisting of clean wood and wood residues. The clean feedstocks also minimize ammonia formation, and ammonia will be at least partially removed in the wet scrubbing step. Hydrocarbons in the gas are viewed as positive since they are readily burned in the turbine and add to the heating value of the gas.

The gas conditioning requirements and the general approaches for the Vermont Gasification Project are conceptually similar to those used at the ARBRE facility, described above. In both cases, bulk particulate removal is followed by hot tar cracking, cooling, filtration, and wet scrubbing. While the specific technologies and catalysts are different in the two cases, the overall approach is similar. The biggest difference in the two cases is the heating value of the fuel gas. This difference will have system implications regarding the volume of gas to be conditioned, the extent of modifications required to burn the gas in the turbine, and possibly gas turbine operating efficiencies. In terms of gas conditioning, however, those differences in product gas characteristics have minimal impact on the basic strategy. In both cases, similar approaches are used to produce clean atmospheric pressure gases that can be compressed for gas turbine use. The overall strategy for the gas conditioning in the Vermont Gasifier Project is summarized in Table 4.7:

**Table 4.7. Gas conditioning in systems requiring significant gas conditioning.
Example: Vermont Gasifier Project. Gasification/gas turbine cogeneration facility**

Constituent	Requirement for Specified Application	Strategy and Comments
Particulates	Requirement: 1.2 mg/Nm ³ for particulates of 10-20 μm (see Table 4.4)	Bulk particulates are removed by the bed recirculation cyclone. Fine particulate and fly ash is removed by bag filters at 200 °C following hot catalytic tar cracking. Final particulate removal is accomplished using a wet scrubber
Alkali	< 0.1 - 0.2 mg/Nm ³	Gas cooling and sequential particulate removal allow condensation of alkali vapors and subsequent collection of entrained solids as particulate material.
Tars	Preference of < 50 mg/Nm ³ to prevent compressor problems	Tars formed during gasification will be catalytically destroyed at ~800 °C using DN34 or other catalyst in a fluidized bed reactor. Gas cool-down and wet scrubbing follow. Following gas cool down, wet scrubbing removes remaining material.
Ammonia and NO _x	Ammonia removal important to limit NO _x formation in turbine exhaust gas.	The final wet scrubbing with dilute acid removes ammonia.
Sulfur-containing Species	Final SO _x emissions dependent on local regulations	Facility uses low-sulfur wood feedstocks; no additional removal necessary
Hydrocarbons	No limit	Hydrocarbons are tolerated since they increase the energy content of the gas

4.2.4.3 Operational Experience and Implications

The first phase of the Vermont Gasification project was to construct the gasifier and provide fuel gas to the McNeil power generating station located adjacent to the gasifier. The gasifier was completed in 1999, and shakedown operations began. Following modifications in early 2000, the gasifier successfully operated in a steady-state mode for several extended periods. By the end of 2000, the gasifier had been operated for a total of about 300 hr, and a test to verify continuous operability over weeklong period was completed (Paisley, 2000).

In the near future, additional testing of the gasifier with a 5-10 MW_e gas turbine is expected. The previous tests with the smaller process development unit in Ohio have shown that this system can be used to power smaller turbines for several hundred hours of operation. It is interesting to note that the work in the smaller system showed that wet scrubbing alone was

insufficient to remove tars from raw product gas. In the absence of the hot catalytic tar cracking, small amounts of tars passed through the wet scrubber and eventually caused problems in the compressor. At this stage of development, it is unclear whether this was simply a problem with that particular scrubber at small scale, or whether there are broader implications with respect to the effectiveness of wet scrubbers for complete tar removal. This issue has significant impacts on system operability and economics but will only be resolved as more data is collected in large-scale systems.

4.2.5 Other Related Systems

It should be noted that other large-scale biomass gasifiers are currently being designed or considered using a similar approach to provide a cool, cleaned fuel gas for use in gas turbines. These include the 35 MW_e WBP/SIGAME Demonstration Project in Brazil and the 13 MW_e Energy Farm Project in Italy. The Brazilian project design is very similar to that of the ARBRE project and uses essentially the same gas conditioning approach, and technologies. The project in Italy uses the general approach of the Amergas facility with partial gas cool down, subsequent particulate removal, and thorough wet scrubbing to remove tars and other gas constituents, although the actual technology components are different. These projects are described in more detail elsewhere (Carpentieri, et al, 1998; Overend, 1998; De Lang, 1998). Coal-fired gasification/gas turbine systems such as the 262 MW_e Wabash River facility in Indiana also use wet scrubbing technologies that produce a cool fuel gas (U.S. Department of Energy, 1996b).

4.3 Hot or Warm Fuel Gases for Systems With Significant Gas Conditioning Requirements

While all technologies can use cool product gases, some such as gas turbines could achieve higher efficiencies by using hot fuel gases. The hot gases retain part or most of the sensible heat from the gasification reaction, and that heat can be used to generate additional electric power.

For this discussion, we define “cool” gases as those with temperatures of <100 °C, although most are nearer 35 °C. Cool gases will be produced when wet scrubbing systems are used. We define warm gases as those with temperatures in the range of ~200–500 °C where heat exchangers are used to recover part of the heat in the gas stream for other process needs. Hot gases, for this discussion are those with temperatures of > 500 °C where minimal gas cooling has occurred. These definitions are intended to be descriptive rather than quantitative and should only be considered as guidelines.

Systems that produce warm or hot gases must still meet all requirements for gas quality including possible limitations on particulates, alkali, tars, ammonia, and other components. The need to both condition the product gas and retain the heat content has strong implications for the system design. Wet scrubbing or electrostatic precipitator systems are not appropriate since they cool the product gas. Particulate and tar removal must therefore be accomplished at higher temperatures. Particulate removal can potentially be accomplished using rigid barrier filters or bag filters depending on the final temperature of the gas. The particulate removal system must deal effectively with alkali as well. Tar removal, where necessary, must largely be accomplished by catalytic tar cracking.

One system is discussed below to illustrate current approaches that produce clean, elevated temperature fuel gases. This example is the Värnamo facility in Sweden. As stated previously, this is not a complete list of all gasifiers systems of this kind but it was chosen to illustrate an approach to producing warm product gas.

4.3.1 Example of a Gasification System Producing Hot, Conditioned Gas: Värnamo Facility in Sweden

4.3.1.1 *Project Overview*

The Värnamo project is a near-commercial scale demonstration of combined cycle heat and power generation in Sweden. Biomass is gasified to provide fuel for power generation using a gas turbine, and excess heat is used to generate steam for additional power production. Heat can also be recovered for district heating purposes. The facility has a capability of producing about 6 MW_e from biomass plus an additional 9 MW_t of district heat (Sydkraft, 1998; Stahl, et al, 1998, 1997; Engstrom, 1998). The project started in the early 1990s and has more hours of successful operational experience than any other biomass gasification/gas turbine system. The demonstration facility, however, was not designed for long-term commercial power generation, and the project was completed in 1999.

Unlike other gasifiers described in this section, the one in Värnamo operates at pressures of 18-22 atm. The pressurized operation of the gasifier contrasts with other facilities described in this report that operate at near-atmospheric conditions. Pressurized operation eliminates the need to compress the fuel gas prior to its use in the gas turbine and increases system toleration to tars that would otherwise accumulate.

The gasifier for the facility is a pressurized, air-blown, circulating bed system. Compressed air for the gasifier is extracted from the compression turbine (approximately 10% of the flow), and is further compressed mechanically. The facility uses finely ground, dried wood and bark feedstock (10 - 20% moisture content) delivered to the power generation site from an adjacent preparation facility. Limited tests with pelletized straw and RDF have also been performed. The feedstock is loaded into a pressurized feed hopper through gate valves and is metered into the gasifier system by screws at a location near the bottom of the gasifier. The bed material for the gasifier includes dolomite or lime that helps destroy tars formed during the gasification reaction. The gasifier typically operates at temperatures of 950-1000 °C, and the fuel gas is a typical low-energy product with a heating value of approximately 5-6 MJ/Nm³.

Gas conditioning is accomplished through sequential steps that retain much of the heat content of the gas. Bulk particulates are removed by the bed recirculation cyclone, similar to other circulating bed gasifiers described previously. The raw product gas is then cooled to about 350 °C in a heat exchanger, and the recovered heat is used to generate steam for the steam turbine. The warm fuel gas then passes through a barrier filter to remove additional ash and particulates. At this temperature, condensed alkali salts can be removed as particulates. The barrier filter consists of an array of filter candles 60 mm OD, 10 mm thick, with a length of 1500 mm. Candles are arranged in six groups of twelve each and are flushed at 15 minute intervals by back pulsing with high-pressure nitrogen. The original ceramic candles were later replaced with sintered metal ones. The barrier filters are reported to work well in long-term operation. The gas also passes through a cyclone filter that removes particulates in the event of the breakage of a barrier filter.

The cleaned product gas at about 350 °C is used to power an ALSTOM industrial gas turbine that has been modified to accommodate the low-energy gas. The combustion gases exiting from the expansion section of the turbine pass through a final heat exchanger to recover additional heat for steam generation. As indicated above, the system includes both gas and steam turbines. Steam is generated from heat recovered in the hot-gas cleanup and gas turbine exhaust sections of the system. The gas turbine produces about 4 MW_e, and the steam turbine produces an additional 2 MW_e for a total net electrical conversion efficiency of 32%. Excess heat (~9 MW_t) from the steam turbine is used in a district heating system. The temperature profile of this system is shown in figure 4.6.

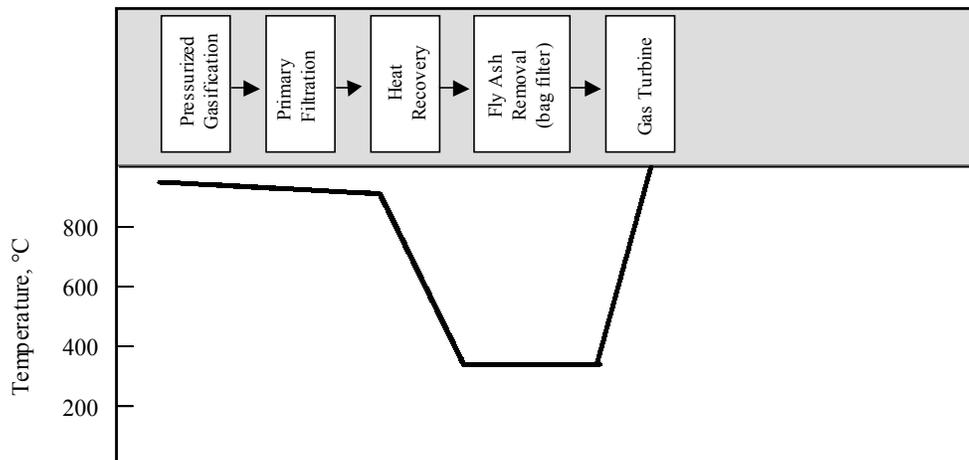


Figure 4.6. Temperature Profile of the Värnamo Gasifier System

4.3.1.2 Gas Conditioning Strategy

The gas conditioning strategy for the Värnamo facility is to produce a warm gas for gas turbine use without wet scrubbing. The gas quality requirements for the gas turbine in this system are very similar to those for other such systems. As summarized previously in Table 4.4, total particulate levels must be low, and the concentrations of alkali must be even lower.

Initial particulate removal in this system is accomplished using the cyclone that separates the circulating bed material from the product gas. Bulk particulates and char remain with the bed material and are recirculated to the gasifier. Heat is then extracted from the gas to generate steam for the steam-cycle portion of the facility, and final particulate removal is accomplished with hot-gas barrier filters. The cooling of the raw product gas ensures condensation of any vaporized alkali. Removal of the remaining particulates is accomplished using candle filters as described above. Some breakage of the original ceramic filters was encountered due to thermal cycling in the demonstration facility, but the metallic filters tested later operated as planned.

In this pressurized system, tar removal is not as critical an issue as in some others. Pressurized gasification eliminates the need to mechanically compress the product gas before it is burned in the gas turbine, thus eliminating a step particularly susceptible to tar accumulation. Partial tar destruction in the raw gas is accomplished by the use of limestone or dolomite in the gasifier bed material. During gasification, tars are catalytically cracked to produce additional fuel gases. The tar content of the fuel gas, however, remains at levels of about 5 g/Nm³. To prevent condensation, the downstream system components such as

pipes and filters are insulated. These steps to prevent cooling are very necessary. In early tests, tar condensation was noted in locations without adequate insulation. Tars also condensed on the fly ash when the candle filters were cleared with pulses of cool nitrogen gas. Condensation was avoided in later tests by system modifications.

Tars arriving at the gas turbine inlet appeared to be burned effectively. Flue gas measurements showed the concentrations of unburned hydrocarbons in the turbine flue gas were lower when biomass fuel gases were used than when petroleum was used as a fuel. The tar in the fuel gas in fact appears to increase its heating content by ~10% over that seen in typical tar-free gases from similar gasifiers, and the extra heat content adds to the efficiency of power generation in the gas turbine.

Sulfur oxide emissions were managed in the Värnamo facility by using clean wood residues. Emissions were measured to be less than the permitted requirements of 25 mg/MJ.

No particular system was included for ammonia removal. Ammonia in the product gas was measured at concentrations of about 700 ppm. Ammonia is converted to NO_x in the gas turbine, and NO_x concentrations of about 60 mg/MJ were measured in the turbine flue gas. This met the regulated limits of 150 mg/MJ prescribed in the permitting process. It should be noted, however, that new regulations would require emission limits of < 50 mg/MJ at this site, and additional efforts to reduce ammonia concentrations in new facilities may be needed. The gas conditioning strategies for the facility are summarized in Table 4.8.

Table 4.8. Gas conditioning in systems requiring significant gas conditioning. Example: Värnamo facility in Sweden. Gasification/gas turbine cogeneration

Constituent	Requirement for Specified Application	Strategy and Comments
Particulates	Requirement: 1.2 mg/Nm ³ for particulates of 10-20 μm (see table 4.5)	Bulk particulates are removed by the bed recirculation cyclone. Fine particulate and fly ash are removed by hot-gas barrier filters (candle filters) at ~350 °C following heat extraction from the raw gas.
Alkali	< 0.1 - 0.2 mg/Nm ³	Gas cooling prior to the barrier filters allow condensation of alkali vapors and subsequent collection of entrained solids as particulate material.
Tars	System is tolerant to tars because the intermediate compression step is eliminated.	Tars formed during gasification are partially destroyed through contact with dolomite in the fluidized bed. Remaining tars (~5g/Nm ³) are burned in the gas turbine. Downstream systems and surfaces are maintained at ~350 °C to prevent tar condensation.

Constituent	Requirement for Specified Application	Strategy and Comments
Ammonia and NO _x	Ammonia removal important to limit NO _x formation in exhaust gas.	No specific ammonia removal step. NO _x emissions were about 60 mg/MJ, less than permit requirements of 150 mg/MJ. Future regulations may reduce limits to about 50 mg/MJ.
Sulfur-containing Species	Final SO _x emissions of <25 mg/MJ by permit regulations	Facility will use low-sulfur woody biomass feedstocks; no additional removal is necessary.
Hydrocarbons	No limit	Hydrocarbons are consumed in the gas turbine; measured emissions lower with biomass fuel gas than petroleum fuels.

4.3.1.3 Operational Experience and Implications

The Värnamo gasification system has more operational experience than any other biomass fired gas turbine system. The gasifier was completed in 1993 and has undergone extensive testing since that time. In total, the gasifier has operated for more than 7000 hours.

The gas turbine was modified for use with the low-energy gas in 1995, and test operations of the integrated biomass fueled power generation system began that year. By the end of 1999, the integrated facility had operated for a total of about 3500 hours, with most of those during 1998 and 1999.

The facility was built as a near-commercial demonstration and was not intended to provide long-term power generation on a commercial basis. The demonstration of the technology was completed in 1999, and the facility has been closed. The experience from this facility shows both that unanticipated problems will occur with first-of-a-kind demonstration facilities, and that such problems can be overcome.

4.4 Synthesis Gases for the Production of Fuels and Chemicals, and Hydrogen for Use With Fuel Cells

The production of biomass gases for either synthesis of fuels/chemicals or for production of hydrogen involves even more extensive gas quality requirements. The basic requirements for synthesis gas (Graham and Bain, 1993) include:

- The product must be a medium-energy gas produced either by indirect heating methods or partial oxidation with separated O₂. Dilution of the product gas with nitrogen from air-blown gasification is unacceptable.
- Pressurized gasification systems are preferred to reduce subsequent mechanical compression requirements.
- Particulate loadings must be minimal, < 0.02 mg/Nm³.
- Tar loadings must be low, < 0.1 mg/Nm³.

- Sulfur levels must be $< 0.1 \text{ mg/Nm}^3$.
- Hydrocarbons must be low to prevent dilution and/or catalyst poisoning.
- Methane, $< 3\%$ or reforming is needed.
- Olefin content $< 4 \text{ mg/Nm}^3$.
- Ethylene content $< 0.1 \text{ mg/Nm}^3$.
- The ratios of H_2 to CO must be appropriate (i.e., for methanol the ratios is $\sim 2.1:1$)

The production of a hydrogen-rich fuel gas for fuel cell applications will also require gas conditioning. While fuel cell requirements are less well documented than those for synthesis systems, the gas quality requirements are likely to be similar to those for synthesis applications. Fuel cell use is described below.

4.4.1 Current Production of Fuels and Chemicals from Synthesis Gas

The use of fossil- and petroleum-derived synthesis gas to produce fuels and chemicals is well established commercially. Methanol is produced in large quantities by the conversion of natural gas or petroleum into a synthesis gas. The gas is then reacted over copper/ zinc catalysts to produce methanol. Over many years, the catalysts have been improved and now exhibit very high specificity toward methanol production. These technologies are very large in size to take advantage of the economies of scale.

Coal has also been used as a feedstock for producing synthesis gas used in production of both methanol and Fischer-Tropsch liquids. Coal is gasified using oxygen-blown gasifiers, and the raw product gas is treated for particulates and tars through the use of multiple wet scrubbers and particulate filters as needed. Sulfur is removed by wet scrubbing in most systems. The synthesis gas is cooled before methanol synthesis to avoid problems with overheating during the exothermic methanol formation reaction. Coal systems, like those for natural gas or petroleum, are large and can take advantage of economies of scale.

At present, some biomass-derived wastes and organic residues are being converted to methanol in multi-fuel gasification facilities. The SVZ Recycling Project in Schwarze Pumpe, Germany, is an example (BTG, 2000). The SVG system gasifies low- or negative-value carbon sources including coal, petroleum coke, high sulfur fuel oil, and waste organic materials to produce a synthesis gas used in part for methanol production and in part for a gas turbine combined cycle power generation system. The facility produces 68 MW_e and has an annual production of 130,000 tons of methanol, equivalent to a total of 250 MW_e.

The facility uses gas-conditioning steps representative of those in a coal-based conversion facility. These include bulk particulate removal, initial heat recovery, catalytic conversion of sulfur-containing species, cooling, and repeated sequential wet scrubbing to remove contaminants. The clean, cooled gas must then be reformed to remove hydrocarbons and shift the H_2 to CO ratios. In this facility, the economics of methanol production are being driven in part by the need to eliminate wastes.

4.4.2 Biomass-based Production of Synthesis Gas

Recent interest has been expressed in producing either methanol or Fischer-Tropsch liquids from biomass (Sethi, et al, 1999; Larson and Haiming, 1999). The economics of methanol production from biomass have been discussed in more detail elsewhere (Wyman, et al, 1993). Facilities based on fossil resources can be larger than those based on biomass, and

they enjoy the advantages of economies of scale. The economies of scale are particularly important for the methanol synthesis loop. At present, there are no stand-alone biomass gasification systems that produce methanol, Fischer-Tropsch liquids, or similar products. Feedstock supply limitations make it difficult to compete on the same scale as natural gas or coal-based facilities. While it is technically feasible to produce clean synthesis gases from biomass using the same, multiple scrubbing processes as those used in coal-based systems, the smaller biomass facilities have not been economically competitive. In late 1999 and early 2000, the prices of both petroleum and natural gas increased rapidly. The impact these price changes will have on the opportunities for biomass-based processes is unclear.

For biomass-based synthesis gas systems, the primary challenge is to create integrated systems that can be economical on a scale compatible with the availability of biomass feedstocks. Although such systems do not currently exist, it is possible to speculate about the types of approaches that could potentially be used. Such processes would incorporate gasifiers that produced raw products with characteristics well-suited for synthesis gas applications, and the gas conditioning steps would be simple. Some considerations are summarized below:

- The system might use a pressurized, turbulent bed gasifier that produced a medium-energy synthesis gas with approximately the correct ratio of hydrogen and carbon monoxide for the gasifier. Pressurized operation would reduce compression requirements in the system. The gasifier could use either an oxygen-blown or an indirectly heated design. Indirectly heated gasifiers could eliminate the need for an oxygen separation facility, but pressurized gasifiers of this type are not currently being developed. Oxygen-blown systems require the O₂ separation facility but are better developed.
- Hot gas conditioning would include initial particulate removal, catalytic tar cracking, hydrocarbon reforming, and sulfur removal. The tar cracking and hydrocarbon reforming would use separate reactors placed in the gas stream to produce gas with H₂, CO, and CO₂ as primary constituents in appropriate ratios. Sulfur removal would be by sorbants, similar to those currently used in developmental coal gasification systems (U.S. Department of Energy, 1996c).
- The gas would be cooled using heat exchangers to recover heat. The cool gas would be filtered using bag or other barrier filters, and scrubbed as a final step to remove ammonia, halides, and any remaining tars and particulates. Carbon dioxide removal by scrubbing may also be necessary.
- Synthesis of fuels and chemicals would be completed using standard processes.

The various technologies that would be part of such a system have been the subjects of recent research and development work, but integrated systems to test concepts for producing synthesis gases from biomass have not yet been demonstrated. Future research and development activities will be required to produce gases from biomass feedstocks that can cost-effectively be used for synthesis of fuels and chemicals.

Although the production of fuels and chemicals via synthesis gases from stand-alone biomass facilities is not currently cost-effective, it may be possible to co-feed biomass-derived synthesis gases into existing facilities such as natural gas- or coal-based methanol production units. Such processes would leverage the economies of scale of already existing in synthesis-based technologies. This could be accomplished either by co-gasifying the biomass with other fuels such as coal (as is currently done in the Schwarz Pumpe facility

described above), or by gasifying biomass separately and cofeeding the product to the synthesis gas conditioning loop.

The addition of biomass to existing systems would also be facilitated by policies or incentives that mandate or favor renewable fuels that reduce net emissions of CO₂. Without such incentives or mandates, there is little current incentive to convert from proven technologies and feedstocks to biomass-based systems with risks. The current situation with biomass derived liquid fuels from synthesis gas is similar to that with biomass fuels from fermentation processes. In both cases, the biomass-derived product costs more than its petroleum or natural gas derived counterparts. However, liquid biofuels from fermentation processes have an increasing market share in some countries. Analysis shows that market penetration is occurring only in those countries where national or regional policies/financial incentives support such development (IEA Bioenergy, 2000). The policies and incentives serve as methods to reach national goals to increase the amounts of chemical and fuels produced from renewable resources and to reduce net carbon dioxide emissions to the atmosphere.

4.4.3 Biomass Gasification to Produce Hydrogen for Fuel Cells

Biomass thermal gasification has also attracted recent interest as a source of hydrogen-rich fuel for use with fuel cells (Amos, 1998; Brown, et al, 1998). The high efficiencies of fuel cells make them potentially attractive for distributed generation applications. At present, the detailed gas quality specifications for biomass-derived fuels for fuel cells have not been well documented. This is due in part to the emerging nature of fuel cell technology and the relatively recent interest in biomass gases for this application. Certain types of fuel cells such as alkaline or phosphoric types have been used for many years for specialized applications or used in near-commercial demonstrations of electricity generation. The alkaline type, for example, was initially designed to operate with purified hydrogen and oxygen in spacecraft. Newer fuel cell types such as solid oxide, polyelectrolyte membrane (PEM), and molten carbonate types are also commercially available or nearing commercial viability. While it is beyond the scope of this report to examine biomass applications with fuel cells in detail, several general conclusions can be drawn.

As shown in Table 4.9, the demands for fuel gas quality vary widely by fuel cell type. It is important to note that the requirements listed in the table refer to the gases entering the fuel cell stack where the actual electricity generation occurs. Present fuel cell manufacturers usually include reformers or similar gas conditioning processes in their system. Regardless of who provides the gas conditioning technology, the integrated gasification/fuel cell system must provide a final gaseous fuel with particular characteristics.

Table 4.9. General fuel cell characteristics (EG&G, et al, 2000; Amos, 1998; Brown, et al, 1998)

Fuel Cell Type	Typical Operation (°C)	Allowable Concentrations of Gas-Phase Constituents:			
		CO	CO ₂	Sulfur	Hydrocarbons
PEM	80	<5 ppm	< 50 ppm	< 1 ppm	Restrictive ^a
Alkaline ^b	120	< 50 ppm ^c	< 50 ppm ^c	< 1 ppm	< 300 ppm
Phosphoric Acid	200	< 1%	Diluent ^d	< 1 ppm	Diluent ^d
Molten Carbonate	650	Unrestricted ^e	Unrestricted ^e	< 0.5 ppm	< 10% ^f
Solid Oxide	1000	Unrestricted ^e	Unrestricted ^e	< 1 ppm	< 10% ^f

^aVariable depending on construction, usually <100 ppm

^bDesigned primarily for use with pure hydrogen and oxygen

^cTotal CO + CO₂ concentrations <50 ppm required. Cell particularly sensitive to CO₂

^dServes primarily as diluent; low concentrations preferred

^eUnrestricted within the range of values typical for gasification

^fHigher concentrations in the fuel stack impact economics due to dilution

In all cases where biomass gasifiers are coupled with fuel cells, effective removal of particulates and tars from the gas stream will be required. For fuel cells operating at low-temperature, tars would present condensation problems similar to those in other types of systems. In the higher temperature systems, tar decomposition could lead to carbon deposition on catalyst surfaces. Data are presently not available to determine whether thermal tar cracking at about 1000 °C in solid oxide types would be sufficient to allow continuous operation. Unreacted tars also represent a loss of fuel content and result in lower overall electric conversion efficiencies.

The high sensitivities of the alkaline and PEM types of fuel cells to CO and CO₂ make them unlikely candidates for use with biomass thermal gasification systems. Phosphoric acid fuel cells are commercially available and have somewhat higher tolerances for CO. However, their use with typical biomass products would still require extensive shift reactions and CO removal. Others, particularly the molten carbonate and solid oxide types have little sensitivity to these components and are potentially suitable for use with biomass gasifiers. Molten carbonate cells, for instance, have been operated in short duration tests of coal-derived gases (EG&G, et al, 2000). Both of these types also permit the presence of air and nitrogen in the fuel gas, which may provide the opportunity for air-blown gasification technologies.

The tolerance of fuel cells to low molecular weight hydrocarbons also varies. In most cases, reforming will reduce the concentrations of hydrocarbons. In the low-temperature systems, unconverted light hydrocarbons primarily dilute the product gas. In high temperature cells, unconverted hydrocarbons may compete with hydrogen for active sites on catalyst surfaces and reduce reaction rates. However, the catalytic and thermal reactions occurring in the high temperature systems also result in reforming of part of the product. As a result, the higher temperature systems are likely to tolerate unreacted hydrocarbons that reach the fuel cell stack, unless those hydrocarbon concentrations become excessive. The ability of the high temperature systems to crack tars and similar materials is not well documented.

While more detailed research is needed, the basic gas conditioning requirements for biomass gases delivered to the fuel cell stack will be similar or only slightly less complex than those for synthesis gases. The final gas compositions will clearly be different for the two applications and the individual gas conditioning step processes may also be somewhat

different. However, the same basic requirements for thorough removal of tars, particulates, and sulfur will be necessary. In addition, shift/reforming reaction issues must be addressed in both systems, although the final product gases will be different. In the fuel cell case, part of the gas conditioning can potentially occur in the fuel cell assembly. However, the final fuel delivered to the fuel cell stack has relatively demanding quality requirements. Additional research and development are needed to answer both technical and economic questions for this technology.

5. DISCUSSION AND RESEARCH NEEDS

5.1 Summary of the Status of Gas Conditioning for Large-Scale Gasification Systems

Large-scale biomass gasification systems are now being successfully operated for heat and steam-cycle power generation. These successes build in part on wide-ranging research and development activities that started in the early 1980s. The successful deployment of large-scale gasifiers has been slower than anticipated by developers. Low prices for conventional fuels and the difficulties of both developing reliable biomass gasifiers and providing sufficiently conditioned gases have proven to be challenging. Facilities built within the last five years, however, have clearly shown that biomass gasification systems can operate reliably, and continuing progress is being made on gas conditioning issues. The progress in several areas is summarized below and remaining issues are discussed.

5.1.1 Progress in Understanding Gas Conditioning Processes

Significant progress has been made over the past 5-10 years toward developing a better understanding of biomass gas conditioning processes and technologies for use in biomass systems. Based on the discussions in Sections 3 and 4 of this report, the progress in specific areas is summarized below.

Particulate Removal:

The application of particulate removal technologies to biomass gasification systems in general has matured over the past decade. Cyclones are routinely being used for bulk particulate removal, and technologies including bag filters and wet scrubbers are being used in large-scale systems. While this progress is incremental in nature, it is required for widespread deployment of gasification technologies.

Demonstrations show that rigid ceramic and metallic candle filters provide a potential method to remove particulates from hot gas streams. This approach can eliminate the need to cool product gases and can result in higher net conversion efficiencies in some systems. This progress represents a significant achievement for biomass systems.

Vaporized Alkali:

In the past decade, significant progress has been made toward understanding the mechanisms of alkali vaporization. Basic and applied studies have provided a good description of reaction pathways and the conditions where alkali salts will vaporize. Using the information that has been developed, it is now possible to largely avoid problems with alkali deposition in gasification systems. The development of this information represents significant progress within the thermochemical conversion research community over the past 5-10 years.

Tests with alkali “getters” that also act as high temperature barrier filters has shown that alkali salts in the gas stream can potentially be reduced to even lower levels for those technologies with very demanding requirements. Additional effort in this area will be necessary to test such concepts at large scale.

Tar Removal:

The subjects of tar characterization, measurement, and removal have been areas of very significant research and development interest over the past decade. The need for better tar measurement methodologies has led to the establishment of recommended protocols that should provide researchers and developers with consistent documentation of tar loadings from different gasifiers. This consistency has not been available in the past, and the acceptance and use of such standardized methodologies should provide significant benefits to the entire gasification community.

RD&D efforts over the past few years have also improved the effectiveness of wet scrubbing systems in removing tars from large-scale systems. Research in various development systems suggests that wet scrubbers are effective in removing tars, at least for some applications. However, there is not uniform agreement on this point, and some researchers are suggesting that tar-sensitive systems will require catalytic tar cracking as well. This research issue will be resolved with ongoing research efforts.

Extensive testing of catalytic tar cracking methods has created a significantly better understanding of this technology over the past decade. Tests have been made with both metallic and non-metallic catalysts, with each having relative benefits. Testing at reasonable scale has shown these systems are effective in removing most tars. The extent to which these technologies can remove tars in full sized, continuously operating units is still unresolved, and additional effort in that area will be needed.

Nitrogen and Sulfur Removal:

R&D activities in the past decade have developed potential methods to reduce ammonia in the product gas, a product that contributes to nitrogen oxide emissions when the gas is burned. The issue of NO_x emissions has gained more prominence as a research issue over the past decade as increasingly restrictive emission regulations have been adopted by most countries. Wet scrubbing systems can remove the ammonia, and large-scale demonstration of these technologies is underway. Catalytic processes have also been tested at smaller scale that have potential for systems where hot fuels gases are preferred.

Sulfur removal from biomass gasifiers continues to be a relatively low priority topic because the naturally occurring concentration of sulfur in most biomass feedstock is low. This topic may increase in priority in the future if higher-sulfur waste materials such as manures or sludges are used in biomass gasifiers.

Hydrocarbon Reforming:

Limited amounts of research have been performed on catalytic reforming of the hydrocarbon components of biomass synthesis gases. Commercial steam reforming catalysts appear to be effective in this application, and they can tolerate limited amounts of sulfur. Interest in this area of research could increase if more emphasis is placed on biomass fuels produced via synthesis gas routes or on hydrogen for fuel cells.

5.1.2 Progress Relating to Gas Conditioning in Integrated Systems

In addition to the individual technologies, progress has also been made over the last decade on integrated systems. The progress in these systems is summarized below:

Systems Producing Fuel Gases with Minimal Gas Conditioning:

Several large-scale commercial heat and power generation facilities have been built recently, including the gasifiers in Lahti, Finland, and Stuttgart, Arkansas discussed previously. These systems use the product gas with minimal gas conditioning for heat and steam-cycle power generation. These facilities have operated successfully over many hours and have clearly demonstrated that reliable large-scale gasifiers are now available. While the gasifier design for each application must be carefully considered, technologies now exist to effectively gasify a variety of biomass feedstocks. The availability and proven reliability of these systems represent significant progress over the past twenty years.

The product gases from these gasifiers can be used reliably in conventional heat and steam-cycle based power generation systems as demonstrated by many hours of successful operation. Bulk particulates are removed from the hot gas by cyclone filters, and tar condensation problems are avoided by keeping the product gas above tar condensation temperatures until it is used in closely-coupled applications. While the conventional steam-cycle power generation technologies limit the overall system efficiency, these newer gasification systems clearly demonstrate that power can be economically produced in situations with low biomass feedstock costs. This accomplishment also represents significant progress as compared to two decades ago when large-scale gasifiers were unproven.

Systems Producing Cool Fuel Gases with Significant Gas Conditioning:

As large-scale gasifier operability and reliability have improved, so has the interest in development of systems that require higher quality product gases. These include higher-efficiency power generation systems such as gas turbines, or other uses such as fuels for internal combustion piston engines. These systems require more rigorous particulate and tar removal from the raw product gas and may require removal of other constituents as discussed.

Systems that cool the product gas prior to its end-use inevitably lose part of the heat content of the product. The resulting loss of overall thermal conversion efficiency, however, may be acceptable or even required to meet end-use requirements. Some technologies including internal combustion engines or compressors require cool fuel gases for thermodynamic or operational reasons. In other integrated systems, the decision to produce cool gas may be based more on the selection of wet scrubbing technologies to meet product gas quality requirements. Wet scrubbers, for example, are effective at removing fine particulates and ammonia.

Research and development activities in smaller-scale demonstration systems have shown that either of two basic approaches have promise for producing clean, cool fuel gases. In both cases, bulk particulates are initially removed from the gas stream using cyclonic filters. In the first approach, fine particulates are then separated from the gas stream by filtration at temperatures above tar condensation temperatures, the gases are cooled, and condensed aerosol tars are physically removed by wet scrubbing methods. As an alternative, tar can be

destroyed catalytically at high temperature, with fine particulate removal accomplished subsequently by filtration and wet scrubbing. These different approaches are reflected in the Amergas and the ARBRE facilities described previously.

Research and development over the past 5-7 years in smaller facilities has resulted in an improved understanding of these two gas-conditioning approaches. In both approaches, wet scrubbing methods have been shown to effectively eliminate both particulates and ammonia from the fuels gas. Research in some smaller demonstration units has also shown that wet scrubbers can effectively remove at least part of the tar aerosols in those systems. However, there is ongoing controversy about the effectiveness of wet scrubbers, particularly with their ability to sufficiently remove tar for gases that must be compressed. In some systems, wet scrubbing alone has proven to be only partially successful. This controversy will ultimately be resolved after additional testing in large-scale facilities.

The high temperature catalytic tar destruction approach potentially eliminates the necessity to handle tars collected from wet scrubbers and produces additional fuel gas. Research on catalytic tar destruction systems has resulted in the identification of improved catalysts and processing techniques. However, the catalytic conversion technology is less well developed and entails higher risk for the first few units.

Because of progress on the gas conditioning issues, several large-scale gasification facilities that will produce cool fuel gases are either being currently tested or are under construction, as discussed in Section 4. The operation of these facilities should provide the data needed to resolve questions about the relative merits of the two basic approaches. The fact that these facilities are being constructed and operated represents major progress, both with the gasification technology itself and with a significantly improved understanding of the gas conditioning processes.

Systems Producing Warm or Hot Fuel Gases with Significant Gas Conditioning:

To reduce heat loss encountered in producing cool gases, increasing interest has also been shown in producing high quality fuel gases that retain much of their heat content. The warm or hot fuel gases would increase thermal conversion efficiencies in systems such as those with gas turbines. Using this approach, tars would be removed by catalytic reaction at high temperature followed by hot gas filtration using barrier filters. The decision to produce warm or hot gases using this approach also has other system design implications. Systems producing clean hot gases will probably be produced with pressurized gasification systems since compression of hot gases is inefficient. In addition, the desire to produce hot gases precludes the use of wet scrubbing or precipitation systems since those technologies cool the gas.

Research and development efforts over the past few years have significantly improved the ability to produce hot or warm biomass gases for uses such as gas turbines. Recent operation of the Värnamo facility in Sweden showed that hot gas ceramic and metal candle filters can effectively clean the product gas. Similar results were also obtained in limited tests at the gasifier demonstration in Hawaii (Lau, 1998; Wiant, et al, 1997, 1994a, 1994b). These filtration systems, which are used extensively in other systems, appear to be suitable for biomass systems.

The progress in this area is illustrated by the successful operation of the gasification/gas turbine system in Värnamo, Sweden, described in Section 4. The commercial-scale

demonstration showed that clean, hot fuel gases could be produced and that they could be used for extended periods to fuel a gas turbine IGCC system. While the technical feasibility of this approach has been shown at reasonable scale, the longer-term economic feasibility is still undetermined. The Värnamo facility was intended to be a demonstration project rather than a long-term power generation facility, and the project has now been completed. Future large-scale commercial facilities will be needed to prove the economic potential of these systems.

The implications of alkali in the hot product gases are also much better understood as a result of research over the past decade. In hot gases, alkali can be vaporized and create deposition problems on cooler downstream surfaces. Research has provided a clearer understanding of alkali salt vaporization mechanisms, which has led to better operational procedures to avoid potential problems. In addition, hot gas alkali “getters” are being developed to further remove this component from the hot gas stream. This research shows good potential, but additional research will be required before they can be commercially tested. Alkali material, viewed several years ago by some as a major impediment to the use of biomass to fuel gas turbine systems, appears to be manageable in these systems if appropriate measures are taken.

An unresolved technical issue for hot gas systems is ammonia control. Ammonia is effectively removed from cool gas streams by wet scrubbing, but it tends to remain in hot gas streams where it can subsequently be converted to NO_x when the gas is burned. Ammonia levels in the raw gas from most gasifiers are acceptable for gas turbines in many locations. However, ammonia control becomes more important in “high attainment” areas where NO_x emissions limits are low (<10 ppm). Some research has been done on catalytic destruction of ammonia, but these concepts have not been tested in large-scale facilities. Better methods to catalytically destroy ammonia in hot gases may be needed.

Systems Producing Synthesis Gases for Fuels, Chemicals, and Hydrogen:

Product gases for synthesis of fuels and chemicals, as well as hydrogen-rich gases for fuel cells, require more demanding cleaning and conditioning. Clean gases for methanol synthesis are currently produced primarily from natural gas or petroleum products, but they are also being produced from dirtier feedstocks including coal and other carbonaceous wastes. Historically, coal has been used as a feedstock for producing both methanol and Fischer-Tropsch liquids. This technology involves multiple filtration, wet scrubbing, and reforming steps prior to product synthesis. Clearly the technology to produce synthesis gases from dirty solid fuels is available and can potentially be applied to biomass systems. However, the economic competitiveness of this approach is more difficult to achieve using biomass.

Similar approaches could also potentially be used for producing hydrogen-rich gases for fuel cells. The compatibility of biomass gasification with fuel cells remains poorly defined. Hydrogen-rich gases from biomass will have to meet at least the same general quality standards as those for synthesis purposes including very low levels of particulates, tars, and alkali in the gas stream. Reforming of the product gas will also be necessary. Depending on the fuel cell technology chosen, subsequent removal of constituents such as CO or CO₂ from the gas stream may be required. Additional work to document fuel cell gas quality requirements as they relate to biomass-based systems is needed. The requirement for gas processing suggests that such systems will be best suited for medium- to large-scale

applications initially. Future progress on both hot gas conditioning and on fuel cell technology will likely be required for these systems to be economical at small scale.

At present, stand-alone biomass facilities for either synthesis gas production or for hydrogen do not exist. This is in part due to the relative cost of biomass as compared to natural gas or heavy petroleum, and in part due to economy of scale limitations imposed by the use of biomass feedstocks. While recent increases in the prices of conventional fuels have made biomass alternatives more appealing, the longer-term differences in feedstock costs are unclear. Biomass-based systems, even the larger systems now being designed, will also have difficulties realizing the economic advantages of economies of scale enjoyed by modern synthesis facilities. Fuel cells offer potential for distributed generation applications, but more R&D is needed for biomass-based systems.

In the opinion of the author, the economical production of synthesis gases from biomass in the nearer term will depend both on technical breakthroughs and on national policy decisions. Technical progress is needed to improve gas-conditioning technologies so that they can be more cost-competitive on the scale appropriate for biomass systems. Examples include improved catalytic systems to both crack tars and reform hydrocarbons simultaneously and improved sorbants for sulfur or ammonia removal. Other approaches may be to co-gasify biomass with feedstocks such as coal or to use biomass gases to supplement the raw products produced from other feedstocks in larger systems. In addition, public policies will be needed to provide a business environment where production of fuels, chemicals, and hydrogen from biomass can be successful. Such policies would recognize the national benefits arising from the use of biomass-derived energy such as economic development, energy security, and energy sustainability, similar to those implemented in some countries for fermentation ethanol.

5.2 Summary of Research and Development Needs

While significant progress has been made on the cleaning and conditioning of biomass gas in large-scale systems, additional research and development activities could assist in the deployment of these technologies. Several issues and needs identified in the preparation of this report are summarized below:

Gas Conditioning Systems:

- Catalysts for tar cracking and hydrocarbon reforming:
Better catalysts for tar destruction and hydrocarbon reforming could improve the quality of product gases. R&D is needed to improve catalytic conversion efficiencies and improve catalyst lifetimes. Catalyst development work, screening activities, and testing of promising candidates would be helpful. Catalyst systems that are effective at both tar cracking and hydrocarbon reforming would improve synthesis gas quality. Improved catalytic destruction of ammonia would also be useful.
- Tar removal in wet scrubbers:
The efficiency of wet scrubbers to sufficiently remove tars from product gases remains controversial for systems with compressors or IC engines. Data from the newly constructed gasifier facilities is needed to resolve this ongoing question.

- Tar characterization and measurement:
Excellent progress has been made in establishing protocols for tar measurements. Ongoing emphasis needs to be placed on using those methods to collect and compare data from various locations.
- Ammonia:
Wet scrubbers effectively remove ammonia, but removal is more difficult in systems producing hot gases. Better catalytic destruction methods are needed for those systems.
- Sorbants:
Recent research on sorbants for alkali removal in biomass systems and sulfur removal in coal-based systems is promising. Additional research on sorbants could lead to improved biomass gas quality. Removal of alkali is very important in systems producing hot fuel gases, and sulfur removal is necessary for synthesis gases. Sulfur removal may also be needed in future facilities that operate on wastes and residues with higher sulfur contents.
- Alkali measurement systems:
Improved analytical techniques and sensors are needed to allow real-time tar, particulate, alkali, and ammonia concentration in gas streams. As improved sensors are developed, more consistent reporting methods also need to be developed to ensure that measurements made at different facilities are made on a comparable basis.
- Integrated gas conditioning systems:
Production of either synthesis gases or hydrogen for fuel cells requires extensive gas processing. Better, integrated gas conditioning systems are needed, particularly those that would be appropriate for the scale of facilities appropriate for biomass.
- Specific needs related to fuel cells:
The need for improvements in small-scale gas conditioning systems is particularly crucial for fuel cell applications. At present, the requirements of fuel cells as they relate to biomass gasification are not well documented. Improved documentation of the issues related to coupling these technologies needs to be made available. Research to develop better, small scale gas conditioning systems is also needed if biomass-powered fuel cells are to reach their full potential.

Gasifiers:

- Pressurized gasification:
Most large-scale gasification systems being built or designed operate at near-atmospheric pressure. Particularly for gas turbine use (but also synthesis gases), pressurized operation would be desirable. Pressurized operation adds additional complexity to many process components including feeding systems. Additional large-scale demonstration of pressurized gasification processes, either air-blown or indirectly heated, is needed to prove the operability and reliability of these systems.
- Feeding systems:
While biomass feeders are available from commercial vendors, experience in many of the gasification facilities has demonstrated that improvements to these systems would be beneficial. This applies to both atmospheric and pressurized systems. R&D is

needed to better understand the handling characteristics of the fibrous biomass feedstock and to develop improved feeders.

Information Dissemination and Policy:

▪ Technical information dissemination:

It is crucial to document the performance of the new, large-scale biomass gasification systems that are being built and operated at this time. This information is important not only in highlighting success stories but also in showing solutions to problems that may arise. The experience at the Värnamo, Sweden facility has been well documented, and this information serves as a valuable technical resource. While large, commercial facilities may have proprietary aspects, detailed reports and operational summaries need to be available to a wide audience. Governments providing funding for these projects are urged to arrange for reasonable documentation, similar in detail to that provided from Värnamo.

▪ Policy:

The deployment of biomass gasification systems for heat, power and fuel applications will benefit from policies that encourage the use of renewable fuels. This is particularly essential in the area of producing fuels via synthesis gases as described previously. Bioenergy, while presently competitive in many markets, will also benefit from policies that favor a transition to a renewable energy economy. For heat and power generation, it is important that regulations be drafted so that biomass gasification systems are defined as “green” processes for converting wastes and renewable energy feedstocks. These types of policies and regulations will be needed if bioenergy is to grow significantly over the next decade or two.

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APPENDIX A. GAS CONDITIONING TECHNOLOGY SURVEY

As part of the ongoing IEA Bioenergy Agreement Task on biomass gasification (IEA Bioenergy 2000), a survey of technologies available for biomass gas conditioning was developed in 1999. The survey was developed for participants to distribute to industries in their own countries. The responses were to be used to develop a listing of available technologies and the companies capable of providing them. As the IEA Bioenergy Task proceeded, it was decided that a world-wide compilation of the capabilities of individual companies was lower priority than other efforts, and the survey was not widely distributed. The survey developed through that effort is attached to this document and can be freely distributed if individuals wish to compile a directory of capabilities in their own region or country.

SURVEY OF COMMERCIAL GAS CLEAN-UP AND GAS CONDITIONING TECHNOLOGIES

1. Basic Information:

Company Name:

Contact Person:

Telephone:

Fax:

Email:

Marketing/Sales Contact:

Telephone:

Fax:

Email:

2. Does your company have a Web Site that describes your products? (Y/N)

Web Site Address:

3. Where are your primary markets? (Check all that apply).

- | | |
|--|---------------------------------|
| <input type="checkbox"/> North America | <input type="checkbox"/> Europe |
| <input type="checkbox"/> Asia/Pacific | <input type="checkbox"/> Other |

4. Which best describes your company's interests? (Check one)

- We are primarily interested in selling **complete biomass gasification systems** that include appropriate gas clean-up systems.
- We are primarily interested in selling gas clean-up **components** that others would use in their systems (skip to question 6).

5a. For developers of gasification systems, please describe your technology (Or attach a brochure).

General Description of Your Company's Technology:

Typical Commercial Applications:

5b. For developers of gasification systems, please provide the following information:

Current Technology status:

- Conceptual/RD&D stage
- Pilot Plant scale facilities in operation
- Commercial scale facilities built
- Extended operation of multiple commercial facilities achieved

Specifications of Gasification Equipment Available From Your Company:

	TYPICAL	Minimum	Maximum
Capacity Biomass feed rate (dry basis):			
Product Gas Heating value (HHV): Gas flow rate:			
Product Gas Quality Particulate Loadings: Particulate Size Range: Tar loadings:			
Temperature of Operation:			
Operational Pressure (atm):			
Approximate Number of Commercial Installations:		N/A	N/A
Unique or Special Characteristics (<i>Describe</i>)			

- Performance Warranty Offered?

Yes

No

If you also sell gas clean-up components and wish to have them included in a directory of suppliers, go to question 6. Otherwise, go to Question 7.

6. For developers of components in the area of gas cleanup and conditioning, what is the range of products your company offers?

Offered by Your Company? <i>Check all that apply:</i>	Technology	Technology Status		
		Conceptual	Pilot Plant	Commercial
6a.	General Particulate Removal			
<input type="checkbox"/>	Cyclones	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
<input type="checkbox"/>	Barrier Filters	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
<input type="checkbox"/>	Wet Scrubbers	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
<input type="checkbox"/>	Electrostatic Technologies	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
<input type="checkbox"/>	Other _____	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
6b.	Tar Removal			
<input type="checkbox"/>	Wet Scrubber Systems	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
<input type="checkbox"/>	Catalytic Technologies	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
<input type="checkbox"/>	Other _____	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
6c.	Specialized Alkali Removal			
<input type="checkbox"/>	Physical Barriers	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
<input type="checkbox"/>	"Getters"	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
<input type="checkbox"/>	Other _____	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
6d.	Other Gas Conditioning			
<input type="checkbox"/>	Ammonia Removal	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
<input type="checkbox"/>	Sulfur Removal	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
<input type="checkbox"/>	Other _____	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>

For companies that would like to be included in a directory of suppliers, please provide information about your technologies in sections 6a. – 6d. below. (Or provide brochures with this information).

6a. PARTICULATE REMOVAL SYSTEMS

(Complete if appropriate, or skip to next section).

<p>General Description of Your Company's Technology:</p> <p>Typical Commercial Applications:</p>

Specifications of Particulate Removal Equipment Available From Your Company:

	TYPICAL	Minimum	Maximum
Mass Flow Rate Capacity:			
Acceptable Upstream Particulate Loadings: Particulate Size Range:			
Downstream Particulate Loadings: Particulate Size Range:			
Temperature of Operation:			
Operational Pressure (atm):			
Pressure Gradient Across System:			
Approximate Number of Commercial Installations:		N/A	N/A
Unique or Special Characteristics (<i>Describe</i>) 			

- | | | |
|--|--------------------------|--------------------------|
| | Yes | No |
| • Performance Warranty Offered? | <input type="checkbox"/> | <input type="checkbox"/> |
| • Your Company has experience with Biomass Gasification? | <input type="checkbox"/> | <input type="checkbox"/> |
| • Your Company has experience with Biomass Combustion? | <input type="checkbox"/> | <input type="checkbox"/> |

6b. TAR REMOVAL SYSTEMS

(Complete if appropriate, or skip to next section)

General Description of Your Company's Technology:

Typical Commercial Applications:

General Description of the Types of Tars Your Equipment is Designed For:

Specifications of Particulate Removal Equipment Available From Your Company:

	TYPICAL	Minimum	Maximum
Mass Flow Rate Capacity:			
Acceptable Upstream Tar Loadings:			
Downstream Tar Loadings:			
Temperature of Operation:			
Operational Pressure (atm):			
Pressure Gradient Across System:			
Approximate Number of Commercial Installations:		N/A	N/A
Unique or Special Characteristics (<i>Describe</i>)			

- | | | |
|--|--------------------------|--------------------------|
| | Yes | No |
| • Performance Warranty Offered? | <input type="checkbox"/> | <input type="checkbox"/> |
| • Your Company has Experience with Biomass Gasification? | <input type="checkbox"/> | <input type="checkbox"/> |
| • Your Company has experience with Biomass Combustion? | <input type="checkbox"/> | <input type="checkbox"/> |

6d. OTHER GAS CONDITIONING

(Complete if appropriate, or skip to next section)

Your Technology removes: *(Check all that apply)*

- Ammonia
 Sulfur (SO_x, H₂S, etc)
 Nitrogen Oxides
 Other *(explain)*

<p>General Description of Your Company's Technology:</p> <p>Typical Commercial Applications:</p>

Specifications of Particulate Removal Equipment Available From Your Company:

	TYPICAL	Minimum	Maximum
Mass Flow Rate Capacity:			
Concentrations prior to cleaning:			
Concentrations after cleaning:			
Temperature of Operation:			
Operational Pressure (atm):			
Pressure Gradient Across System:			
Approximate Number of Commercial Installations:		N/A	N/A

<p>Unique or Special Characteristics <i>(Describe)</i></p>
--

- | | | |
|--|--------------------------|--------------------------|
| | Yes | No |
| • Performance Warranty Offered? | <input type="checkbox"/> | <input type="checkbox"/> |
| • Your Company has Experience with Biomass Gasification? | <input type="checkbox"/> | <input type="checkbox"/> |
| • Your Company has experience with Biomass Combustion? | <input type="checkbox"/> | <input type="checkbox"/> |

7. OTHER GAS CLEAN-UP OR CONDITIONING CAPABILITIES:

(Describe)

8. OTHER COMMENTS:

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13. ABSTRACT (Maximum 200 words) As a result of environmental and policy considerations, there is increasing interest in using renewable biomass resources as feedstock for power, fuels, and chemicals and hydrogen. Biomass gasification is seen as an important technology component for expanding the use of biomass. Advanced biomass gasification systems provide clean products that can be used as fuel or synthesis gases in a variety of environmentally friendly processes. Advanced end-use technologies such as gas turbines or synthesis gas systems require high quality gases with narrowly defined specifications. Other systems such as boilers may also have fuel quality requirements, but they will be substantially less demanding. The gas product from biomass gasifiers contains quantities of particulates, tars, and other constituents that may exceed these specified limits. As a result, gas cleaning and conditioning will be required in most systems. Over the past decade, significant research and development activities have been conducted on the topic of gas cleanup and conditioning. This report provides an update of efforts related to large-scale biomass gasification systems and summarizes recent progress. Remaining research and development issues are also summarized.				
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