

PROCESSING BIOMASS AND ENERGY

CROSS REFERENCE TO RELATED APPLICATIONS

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This application claims priority from the following provisional applications:
USSN 61/774,684, filed March 8, 2013; USSN 61/774,773, filed March 8, 2013; USSN
61/774,731, filed March 8, 2013; USSN 61/774,735, filed March 8, 2013; USSN
61/774,740, filed March 8, 2013; USSN 61/774,744, filed March 8, 2013; USSN
10 61/774,746, filed March 8, 2013; USSN 61/774,750, filed March 8, 2013; USSN
61/774,752, filed March 8, 2013; USSN 61/774,754, filed March 8, 2013; USSN
61/774,775, filed March 8, 2013; USSN 61/774,780, filed March 8, 2013; USSN
61/774,761, filed March 8, 2013; USSN 61/774,723, filed March 8, 2013; and USSN
61/793,336, filed March 15, 2013. The full disclosure of each of these provisional
15 applications is incorporated by reference herein.

BACKGROUND

Many potential lignocellulosic feedstocks are available today, including
20 agricultural residues, woody biomass, municipal waste, oilseeds/cakes and seaweed, to
name a few. At present, these materials are often under-utilized, being used, for
example, as animal feed, biocompost materials, burned in a co-generation facility or even
landfilled.

Lignocellulosic biomass includes crystalline cellulose fibrils embedded in a
25 hemicellulose matrix, surrounded by lignin. This produces a compact matrix that is
difficult to access by enzymes and other chemical, biochemical and/or biological
processes. Cellulosic biomass materials (*e.g.*, biomass material from which the lignin
has been removed) is more accessible to enzymes and other conversion processes, but
even so, naturally-occurring cellulosic materials often have low yields (relative to
30 theoretical yields) when contacted with hydrolyzing enzymes. Lignocellulosic biomass

is even more recalcitrant to enzyme attack. Furthermore, each type of lignocellulosic biomass has its own specific composition of cellulose, hemicellulose and lignin.

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SUMMARY

Many processes are disclosed herein for saccharifying or liquifying a biomass material, *e.g.*, cellulosic, lignocellulosic and/or starchy feedstocks, by converting biomass material to low molecular weight sugars, *e.g.*, saccharifying the feedstock using
10 an enzyme, *e.g.*, one or more cellulase and/or amylase. The invention also relates to converting a feedstock to a product, *e.g.*, by bioprocessing, such as fermentation. The processes include utilizing residues from one or more stages of the process for energy generation.

In one aspect the invention relates to a method of generating energy including
15 combusting a saccharified biomass material to produce energy. Optionally, the energy can be in the form of electric energy, heat energy or combinations of these. The saccharified material can include cells, such as cells selected from the group consisting of yeast cells, bacterial cells, fungal cells and mixtures of these cells. The cells can include whole cells (*e.g.*, living, dormant and/or dead) or parts of cells (*e.g.*, lysed and/or
20 otherwise dead and destroyed cells). In addition or alternatively the saccharified material can include protein material (*e.g.*, an enzyme material, a denatured enzyme material, peptides and/or amino acids). In addition or alternatively, the saccharified material can include inorganic solids, such as inorganic materials selected from the group consisting of diatomaceous earth, celite, silica, pumice, perlite, alumina, zeolites, sand and mixtures
25 of any of these.

In some instances, the saccharified biomass material comprises lignocellulosic residue from lignocellulosic material that has been treated, for example with accelerated electrons from an electron accelerator, to reduce its recalcitrance prior to saccharification. For example, when treated with electrons, the electrons can have an
30 average energy between about 0.3 MeV and about 5 MeV, such as between about 0.5 MeV and about 3.5 MeV or between about 0.8 MeV and about 2 MeV. The lignocellulosic biomass can be treated to a total dose between about 10 Mrad and about 100 Mrad, such as between about 15 Mrad and about 50 Mrad, between about 20 Mrad and about 45 Mrad, or between about 25 Mrad and about 40 Mrad. Optionally, the

saccharified biomass is collected utilizing a rotary drum filter and/or a centrifuge, such as a decanter centrifuge, prior to combustion.

In some instances, the saccharified biomass material includes less than 60 percent moisture prior to it being combusted, such as less than about 55, 50, 45, 40, 35, 30, 25, 20, 15 or even less than about 5 percent moisture. For example, the biomass can be dried so that it has less than about 60 percent moisture prior to combustion (*e.g.*, dried to have less than 55, 50, 45, 35, 30, 25, 20, 15 or even less than 5 percent moisture). Optionally, the saccharified biomass material includes less than 35 percent by weight carbohydrates, such as less than 33, 30, 25, 20, 18, 16, 14, 12, 10 or even less than 8 percent on a dry basis. The saccharified material can be combusted and the combustion can produce greater than about 3500 BTU per pound, such as greater than about 4000, 4500, 5000, greater than 6000 or even greater than about 7000 BTU per pound. Optionally, the saccharified biomass material has less than 50 percent moisture, such as less than 45 or 40 percent, and the combustion produces greater than about 4000 BTU per pound of the material. The saccharified biomass material can include less than 5 percent ash after combustion, such as less than 4, 3, 2.5, 2.0 or even less than 1.5 percent. In addition or alternatively, the saccharified biomass material includes less than 0.5 percent sulfur, such as less than 0.4, 0.3, 0.2, 0.1 or even less than 0.075 or less than 0.05 percent sulfur.

In some other instances, a boiler is utilized during the combustion, for example, a boiler selected from the group consisting of a stoker grate boiler, a fluidized bed boiler and a co-fired boiler. For example, a co-fired boiler used for co-firing natural gas or coal can be utilized with the biomass. Alternatively, during combustion, a gasifier is utilized, such as a fixed bed or a fluidized bed gasifier.

In another aspect the invention relates to a method of processing a biomass material. The method includes processing a first portion of lignocellulosic material into a product and a solid residue and combusting the solid residue in a boiler to produce steam. The method can include coupling the steam with a turbine to produce electricity. The energy produced (*e.g.*, the heat from the steam and/or the electricity from the steam turbine) can be utilized to process a second portion of lignocellulosic material into a product. The processing of the biomass can include irradiating the biomass (*e.g.*, with an electron beam) and optionally, saccharifying the irradiated biomass, for example with an enzyme. The saccharification can produce sugars, for example glucose and/or xylose. Optionally the processing of the lignocellulosic material can include fermentation.

In some instances, the solid residue is dried prior to being combusted, for example, such that the moisture content is reduced to less than about 25 wt.% water, *e.g.*, less than about 20 wt.%, less than 15 wt.%, less than about 10 wt.%, less than about 5 wt.%, less than about 1 wt.% or even less than about 0.01 wt.%. The residue, when in
5 dry form with less than about 5 wt.% water, can have an energy content of at least 4000 BTU per pound of residue. Optionally, the solid residue is dried using a screw dryer (*e.g.*, a screw conveyor with a heated flights, shaft and/or trough). Optionally, the residue is combined with a drying agent, for example, a fine biomass material. For example, a dry biomass can be mixed in with the solid residue, wherein the content of dry biomass
10 in the mixture is at least 1 wt.%, at least 2 wt.%, at least 3 wt.%, at least 4 wt.%, at least 5 wt.%, at least 6 wt.%, at least 7 wt.%, at least 8 wt.%, at least 9 wt.%, at least 10 wt.%, at least 15 wt.%, at least 20 wt.% or even between about 20 wt.% and about 30 wt.%. For example, the dry biomass can have a moisture content of less than about 25, 20, 15, 10, 5 or even less than about 1 percent moisture. For example, a fine biomass material
15 can have a medium particle size less than about 1 mm, less than about 500 μm or less than about 100 μm . The combination of the residue with the dry biomass (*e.g.*, fine biomass material) can dry or further dry the material. The amount can be added, in addition to, or alternatively to, drying to provide a dry material, such that the moisture content is reduced to less than about 25 wt.% water, *e.g.*, less than about 20 wt.%, less
20 than 15 wt.%, less than about 10 wt.%, less than about 5 wt.%, less than about 1 wt.% or even less than about 0.01 wt.%. The residue can be formed into a cake, pellet, densified shape, powder or combinations of these prior to being combusted (*e.g.*, optionally under pressure, and/or while drying). The residue can include at least 0.1% (*e.g.*, at least 0.2%, at least 0.5% or even at least 1%) nitrogen in the form of a nitrogen(III) compound, for
25 example, the nitrogen compound can be or derived from the group consisting of proteins, denatured proteins, protein residues, amino acids, amino acid residues, urea, ammonia and combinations of these.

The biomass materials used can, for example, be selected from the group consisting of wood, particle board, sawdust, agricultural waste, sewage, silage, grasses,
30 rice hulls, bagasse, cotton, jute, hemp, flax, bamboo, sisal, abaca, straw, corn cobs, corn stover, switchgrass, alfalfa, hay, coconut hair, seaweed, algae, and combinations and of these.

By utilizing the residues from many of the processes disclosed herein to provide energy (*e.g.*, for co-generation), the cost of the feedstock conversion process can be

significantly reduced, both by reducing energy costs and minimizing the need for waste disposal. In addition, since the residues are biomass derived, the net carbon emissions for the entire process are close to zero. As a result, the economic viability and profitability of the feedstock conversion process can be markedly enhanced. In addition, the residues from the processes have a high heat content since there can be a high lignin content in the residue *e.g.*, higher than the feedstock such as a lignocellulosic material. Another advantage of some of the methods described herein is that the residues require little or even no drying since they can be combined with dry biomass such as fines produced in the processing of the biomass. In addition to providing a dryer material to combust, the dried material can be easier to convey. Finally, the methods can be advantageous because in some instances the residues can include organic nitrogen (III) compounds that during combustion can react to reduce NO_x emissions.

Implementations of the invention can optionally include one or more of the following summarized features. In some implementations, the selected features can be applied or utilized in any order while in other implementations a specific selected sequence is applied or utilized. Individual features can be applied or utilized more than once in any sequence and even continuously. In addition, an entire sequence, or a portion of a sequence, of applied or utilized features can be applied or utilized once, repeatedly or continuously in any order. In some optional implementations, the features can be applied or utilized with different, or where applicable the same, set or varied, quantitative or qualitative parameters as determined by a person skilled in the art. For example, parameters of the features such as size, individual dimensions (*e.g.*, length, width, height), location of, degree (*e.g.*, to what extent such as the degree of recalcitrance), duration, frequency of use, density, concentration, intensity and speed can be varied or set, where applicable, as determined by a person of skill in the art.

Features, for example, include: methods of generating energy; generating heat energy; generating electrical energy; combusting a saccharified material to produce energy; combusting a saccharified material that includes cells; combusting a saccharified material that includes yeast cells; combusting a saccharified material that includes fungal cells; combusting a saccharified biomass that includes protein material; combusting a saccharified biomass that includes an enzyme material; combusting a saccharified biomass that includes denatured enzyme material; combusting a saccharified lignocellulosic residue derived from lignocellulosic material that has been treated to reduce its recalcitrance prior to saccharification; combusting a saccharified

lignocellulosic residue derived from lignocellulosic material that has been treated with accelerated electrons to reduce its recalcitrance prior to saccharification; combusting a saccharified lignocellulosic residue derived from lignocellulosic material that has been treated with accelerated electrons having an average energy between about 0.3 MeV and about 5 MeV prior to saccharification; combusting a saccharified lignocellulosic residue derived from lignocellulosic material that has been treated with accelerated electrons having an average energy between about 0.5 MeV and about 3.5 MeV prior to saccharification; combusting a saccharified lignocellulosic residue derived from lignocellulosic material that has been treated with accelerated electrons having an average energy between about 0.8 MeV and about 2 MeV prior to saccharification; combusting a saccharide lignocellulosic residue derived from lignocellulosic material that has been treated with accelerated electrons to a total dose between about 10 Mrad and about 100 Mrad prior to saccharification; combusting a saccharified lignocellulosic residue derived from lignocellulosic material that has been treated with accelerated electrons to a total dose between about 15 Mrad and about 50 Mrad prior to saccharification; combusting a saccharified lignocellulosic residue derived from lignocellulosic material that has been treated with accelerated electrons to a total dose between about 20 Mrad and about 45 Mrad prior to saccharification; combusting a saccharified lignocellulosic residue derived from lignocellulosic material that has been treated with accelerated electrons to a total dose between about 25 Mrad and about 40 Mrad prior to saccharification; combusting a saccharified material that includes inorganic solids; combusting a saccharified material that includes diatomaceous earth; combusting a saccharified material that includes silica; combusting a saccharified material that includes pumice; combusting a saccharified material that includes perlite; combusting a saccharified material that includes alumina; combusting a saccharified material that includes zeolites; combusting a saccharified material that includes zeolites; combusting a saccharified material that includes sand; combusting a saccharified material that includes less than 60 percent moisture; combusting a saccharified material that includes less than 50 percent moisture; combusting a saccharified material that includes less than 45 percent moisture; combusting a saccharified material that includes less than 40 percent moisture; combusting a saccharified material that includes less than 30 percent moisture; combusting a saccharified material that includes less than 20 percent moisture; combusting a saccharified material that includes less than 10 percent moisture; combusting a saccharified material that includes less than 5 percent moisture;

combusting a saccharified material that includes less than 0.5 percent sulfur; producing greater than about 3500 BTU of energy per pound by the combustion of a saccharified biomass material; producing greater than about 4000 BTU/lb of energy by the combustion of a saccharified biomass material; producing greater than about 4500
5 BTU/lb of energy by the combustion of a saccharified biomass material; producing greater than about 5000 BTU/lb of energy by the combustion of a saccharified biomass material; producing greater than about 6000 BTU/lb of energy by the combustion of a saccharified biomass material; producing greater than about 7000 BTU/lb of energy by the combustion of a saccharified biomass material; combusting a saccharified biomass
10 material that includes less than 35 percent by weight carbohydrates on a dry basis; combusting a saccharified biomass material that includes less than 30 percent by weight carbohydrates on a dry basis; combusting a saccharified biomass material that includes less than 25 percent by weight carbohydrates on a dry basis; combusting a saccharified biomass material that includes less than 20 percent by weight carbohydrates on a dry
15 basis; combusting a saccharified biomass material that includes less than 10 percent by weight carbohydrates on a dry basis; combusting a saccharified biomass material utilizing a boiler; combusting a saccharified biomass material utilizing a stoker grate boiler; combusting a saccharified biomass material utilizing a fluidized bed boiler; combusting a saccharified biomass material utilizing a co-fired boiler; utilizing a gasifier
20 while combusting a saccharified biomass material; collecting the solids from a saccharified biomass material using a rotary drum filter and combusting the collected material; collecting the solids of a biomass material using a centrifuge and combusting the collected material.

Features, for example, can also include; processing a biomass material;
25 processing a portion of a lignocellulosic material into a product and a solid residue; combusting a solid residue in a boiler to produce steam; coupling steam to a turbine to produce electricity; using steam and electricity to process a portion of a lignocellulosic material into a product; using steam to process a portion of a lignocellulosic material into a product; using electricity to process a portion of a lignocellulosic material into a
30 product; irradiating a lignocellulosic material; saccharifying a lignocellulosic material; producing glucose by saccharifying a lignocellulosic material; producing xylose by saccharifying a lignocellulosic material; fermenting a lignocellulosic material; drying a solid residue prior to combusting the solid residue; reducing the moisture content of a solid residue to less than about 25 wt.% water prior to combusting the solid; reducing the

moisture content of a solid residue to less than about 20 wt.% water prior to combusting the solid; reducing the moisture content of a solid residue to less than about 15 wt.% water prior to combusting the solid; drying a solid residue using a screw dryer prior to combusting the solid; combining a solid residue with a drying agent prior to combusting the solid residue; combining a solid residue with a dry biomass wherein the content of the dry biomass in the mixture is at least 1 wt.%; combining a solid residue with a dry biomass wherein the content of the dry biomass in the mixture is at least 2 wt.%; combining a solid residue with a dry biomass wherein the content of the dry biomass in the mixture is at least 3 wt.%; combining a solid residue with a dry biomass wherein the content of the dry biomass in the mixture is at least 4 wt.%; combining a solid residue with a dry biomass wherein the content of the dry biomass in the mixture is at least 5 wt.%; combining a solid residue with a dry biomass wherein the content of the dry biomass in the mixture is at least 6 wt.%; combining a solid residue with a dry biomass wherein the content of the dry biomass in the mixture is at least 7 wt.%; combining a solid residue with a dry biomass wherein the content of the dry biomass in the mixture is at least 8 wt.%; combining a solid residue with a dry biomass wherein the content of the dry biomass in the mixture is at least 9 wt.%; combining a solid residue with a dry biomass wherein the content of the dry biomass in the mixture is at least 10 wt.%; combining a solid residue with a dry biomass wherein the content of the dry biomass in the mixture is at least 15 wt.%; combining a solid residue with a dry biomass wherein the content of the dry biomass in the mixture is at least 20 wt.%; combining a solid residue with a dry biomass wherein the content of the dry biomass in the mixture is between about 20 wt.% and 30wt.%; combining a solid residue with a dry biomass wherein the dry biomass has a moisture content less than about 25 percent; combining a solid residue with a dry wherein the dry biomass has a moisture content less than about 20 percent; combining a solid residue with a dry wherein the dry biomass has a moisture content less than about 15 percent; combining a solid residue with a dry wherein the dry biomass has a moisture content less than about 10 percent; combining a solid residue with a dry wherein the dry biomass has a moisture content less than about 5 percent; combining a solid residue with a dry wherein the dry biomass has a moisture content less than about 1 percent; combining a solid residue with a fine biomass material prior to combusting the solid residue; a dry biomass can include a fine biomass material; combining a solid residue with a biomass material having a medium particle size of less than about 1 mm prior to combusting the solid residue; combining a solid residue with a biomass material

having a medium particle size of less than about 500 micro meters prior to combusting the solid residue; forming a residue into cakes prior to combusting the residue; forming a residue into pellets prior to combusting the residue; forming a residue into densified shapes prior to combusting the residue; forming a residue into powder prior to
5 combusting the residue; combusting a residue that has an energy content of at least 4000 BTU per pound when it is in a dry form with less than 5 wt.% water; combusting a residue that includes 0.1% nitrogen in the form of a nitrogen(III) compound; combusting a residue that includes 0.1% nitrogen provided from proteins; combusting a residue that includes 0.1% nitrogen provided from protein residues; combusting a residue that
10 includes 0.1% nitrogen provided from amino acids; combusting a residue that includes 0.1% nitrogen provided from amino acid residues; combusting a residue that includes 0.1% nitrogen provided from urea; combusting a residue that includes 0.1% nitrogen provided from ammonia; processing a lignocellulosic material that includes wood; processing a lignocellulosic material that includes particle board; processing a
15 lignocellulosic material that includes sawdust; processing a lignocellulosic material that includes agricultural waste; processing a lignocellulosic material that includes sewage; processing a lignocellulosic material that includes silage; processing a lignocellulosic material that includes grasses; processing a lignocellulosic material that includes rice hulls; processing a lignocellulosic material that includes bagasse; processing a
20 lignocellulosic material that includes cotton; processing a lignocellulosic material that includes jute; processing a lignocellulosic material that includes hemp; processing a lignocellulosic material that includes flax; processing a lignocellulosic material that includes bamboo; processing a lignocellulosic material that includes sisal; processing a lignocellulosic material that includes abaca; processing a lignocellulosic material that
25 includes straw; processing a lignocellulosic material that includes corn cobs; processing a lignocellulosic material that includes corn stover; processing a lignocellulosic material that includes switchgrass; processing a lignocellulosic material that includes alfalfa; processing a lignocellulosic material that includes hay; processing a lignocellulosic material that includes coconut hair; processing a lignocellulosic material that includes
30 seaweed; processing a lignocellulosic material that includes algae;

All publications, patent applications, patents, and other references mentioned herein or attached hereto are incorporated by reference in their entirety for all that they contain.

DESCRIPTION OF THE DRAWINGS

FIG. 1 is a flow diagram showing an example of a co-generation process.

FIG. 2 is a diagram illustrating the flow of fuel to the co-generation facility and
5 flow of energy back to various steps in the feedstock conversion process.

DETAILED DESCRIPTION

Using the systems, equipment and methods described herein, biomass (*e.g.*, plant
10 biomass, animal biomass, paper, and municipal waste biomass) can be processed to produce useful intermediates, products and energy, for example by cogeneration..

Cogeneration, also known as Combined Heat and Power (CHP) is the simultaneous production of electricity and heat from a single fuel source, or multiple fuel sources in the case of co-firing. Some biomass processing methods and systems are
15 described in Biomass Technology Review, October 21, 2010, pages 1 to 52 by McHale and Associates, Inc. and Biomass Conversion Technologies, by the EPA Combined Heat and Power Partnership accessed by internet on Feb 27, 2013 pages 30 to 61 at www.epa.gov; the entire disclosures of which are herein incorporated by attachment in the appendix. Any process, equipment or system described in this document, attached in
20 the appendix, can be used in/with any process, equipment or system described anywhere herein. For example, Stoker grate underfired stoker boilers can be used to burn saccharified biomass.

FIG. 1 shows an example of a cogeneration process. Initially, boiler feed water **10** and fuel sources **20** are fed to one or more boilers **30**. The fuel sources include the
25 solid residues discussed herein, and may optionally include other fuels such as natural gas, waste gases generated by the feedstock conversion process, and/or a portion of the feedstock used in the feedstock conversion process. Steam is generated in the boilers, which is input to one or more super heaters **40**, which super heat the steam, *e.g.*, to 500 PSIG and 650 DEG F. This steam is then injected into one or more turbines **50**, where it
30 turns discs or other turbine elements, which in turn rotate a shaft generating mechanical energy. This mechanical energy is then input to a generator, where it is converted to electricity **70**. Meanwhile, cooled steam exhausted from the turbines, which is still at elevated temperature and pressure (*e.g.*, 80 PSIG and 310 DEG F), can be utilized in the feedstock conversion plant for heating or other purposes **60**. Electrical energy from the

generator (*e.g.*, at 4160 Volts) is passed to transformers, *e.g.*, two transformers, where it is stepped down to allow its use in the plant **80** (*e.g.*, to 480 Volts) and/or stepped up for export to the grid **90** (*e.g.*, to 113,000 Volts).

Details of these and other steps in a cogeneration process according to one
5 implementation will now be described.

In some embodiments the materials to be used are dried. The solid residues from the various stages of the feedstock conversion process may in some cases have a moisture content of from about 10% to 50% or more. This relatively high moisture content can impact the operation of the boiler, in that some of the energy in the boiler
10 will be consumed in vaporizing the moisture, thus reducing the temperature and efficiency of the boiler. Thus, in some implementations, the solid residue is dried prior to being combusted, for example to a moisture content of less than about 60 wt.%, (*e.g.*, less than about 55 wt.%, less than about 50 wt.%, less than about 45 wt.%, less than , about 40 wt.%, less than about 35 wt.%, less than about 30 wt.%, less than about 25
15 wt.%, less than about 20 wt.%, less than about 15 wt.%, less than about 10 wt.%, or even less than about 5 wt.%.

In some implementations the cogeneration system is equipped with a screw type dryer that is used to heat dry the wet residue. For example an indirect heat exchanger may be used to heat bulk biomass solids, filter cakes, paste and/or sludge.

20 The dryer may be, for example, a Hollow Flite Screw Dryer. In this type of dryer individual particles are heated as they come in contact with the outer surfaces of hollow flights, shaft and trough which contain a heat transfer material, *e.g.*, a thermal oil. There is no contamination of the material being dried, as it does not come in contact with the heat transfer material. The product is continuously conveyed in an axial direction by
25 rotating screw flights along a jacketed trough. The dryer uses indirect heat exchange, providing excellent product temperature control. The heat transfer material is also recycled, minimizing heat losses and increasing efficiency. The thermal energy used to heat the heat transfer fluid is preferably provided by the power produced by the cogeneration process.

30 In other implementations, the wet residue may be dried by utilizing heat from anywhere and including the boiler and the heating stack. For example hot gases from the boiler can be used, or heat from a stack (*e.g.*, utilizing a heat exchanger).

In addition or alternatively to drying of the residues as described above, the residues can be combined with a drying agent such as a dry biomass. For example, a dry

biomass can have less water content than the residues, to adjust the total average water content. For example, the dry biomass can, have a moisture content of less than about 25, 20, 15, 10, 5 or even less than about 1 percent moisture. The dry biomass can be sourced, for example, from incoming un-processed biomass as well as any biomass that has been
5 processed by the methods described herein (*e.g.*, fines from the comminution step). For example, a dry biomass can be mixed in with a wet residue from processing described herein, wherein the content of dry biomass in the mixture is at least 1 wt.%, at least 2 wt.%, at least 3 wt.%, at least 4 wt.%, at least 5 wt.%, at least 6 wt.%, at least 7 wt.%, at least 8 wt.%, at least 9 wt.%, at least 10 wt.%, at least 15 wt.%, at least 20 wt.% or even
10 between about 20 wt.% and about 30 wt.%. For example, a residue derived from saccharified biomass can be combined with non-saccharified biomass. The fine biomass material can have a medium particle size less than about 1mm (*e.g.*, 500 μ m or 100 μ m). Preferably the drying agent has moisture content lower than that of the wet residue.

Optionally dried material is conveyed to the boiler operations. In some
15 implementations, solid residues are delivered to the boiler via conveyors that initially deliver the residues into a storage area near the boiler room. In the storage area the biomass is optionally blended with other unused raw biomass and then loaded into a storage bin. The storage bin is fitted with hydraulically driven pusher plates that constantly transport solid fuel to a through-chain conveyor, which supplies fuel to the in-
20 feed section of the boiler. The hydraulically driven in-feed conveyor is also fitted with a pusher plate that pushes the fuel into metering “dump bins.” The metering bins dump the fuel into the combustion chamber in the boiler. These dump bins are helpful in delivering wet residues, which may be difficult to feed using a hopper or other typical feeding technique due to their possible agglomeration and poor flow properties.

25 Once the fuel is in the combustion chambers, the biomass is subjected to a thermochemical combustion process under oxygen deficit conditions, leading to the production of hot (>1800 DEG F) gases and the degradation of the biomass. The biomass (*e.g.*, saccharified biomass) can produce greater than 3500 BTU per pound, such as greater than 4000, 4500, 5000, greater than 6000 or even greater than 7000 BTU per
30 pound. The biomass is converted to ash. The ash content of the biomass can be less than 5 wt.%, (*e.g.*, less than about 4 wt.%, less than about 3 wt.%, less than about 2.5 wt.%, less than about 2.0 wt.%, less than about 1.5 w.t.%). The sulfur content of the saccharified biomass can be less than about 0.5 % (*e.g.*, less than about 0.4, 0.3, 0.2, 0.1, 0.075 or even less than about 0.05). The resulting hot gases travel to an upper drum in

the boiler where the water is vaporized to steam. The steam then passes to the super heater where it is heated further by the hot flue gases. The resulting steam rate from both boilers may be, for example, 103,000 PPH (pounds per hour), at 500 PSIG and 650 DEG F.

5 To maintain proper operation of the boilers, in some implementations each boiler is fitted with an economizer and a recuperater to capture all the waste heat from the flue gas. The economizer heats up the boiler feed water before it enters the upper drum where a water level is always maintained to continuously supply steam; the recuperater also heats up fresh air, which is supplied by a forced draft fan to maintain combustion in the
10 boiler.

The boiler feed water travels around the perimeter of the boiler through inner tubes, and loops around between the upper drum and a lower drum as it is further heated.

Occasionally, a boiler blow down may be performed, during which water from the lower drum is dumped and replaced with fresh boiler feed water. This operation may
15 be done either manually or automatically and is used to remove the dissolved solids and particles entering the boiler through the make-up water.

If the dissolved solids are not removed they will build up and finally the concentration will reach a level where the boiler operation becomes impossible. In addition, if solids are not purged from the boiler they can lead to scale formation,
20 carryover, corrosion, and/or embrittlement

In some embodiments, the flue gas is directed from the super heater, the economizer, and the recuperator to an Electrostatic Precipitator by an induced draft. The Electrostatic Precipitator, discussed below, removes particulate material from the flue gas and may in some cases be more effective than a bag house.

25 The Electrostatic Precipitator contains six major components: discharge electrodes, collection electrodes, rappers, hoppers, outer shell, and an electric system.

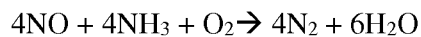
The discharge electrodes release an electric charge, usually negative, to pollutant particles in the gas stream. The collection electrodes, which may be, for example, tubes or plates, collect the charged particles and have a charge opposite to that of the discharge
30 electrodes which causes the particles to migrate toward them.

The particles are removed from the electrodes by the rappers, which provide vibration or shock to both the collection and discharge electrodes causing the particles to fall into the hoppers where they are temporarily stored.

The outer shell encloses the electrodes and supports the precipitator components. The shell is covered with insulation to conserve heat and prevent corrosion. The outer shell and be made of steel.

The electric system, also called the transformer-rectifier, controls the strength of the electric field between the discharge and collection electrodes. The electric system used standard current 480 volts and steps it up to as high as 70,000 volts. The rectifier part of the electric system converts the current from alternating to direct current.

The flue gas exiting the electrostatic precipitator is free or substantially free of particles but can contain NO_x compounds. NO_x is a generic term for mono-nitrogen oxides (*e.g.*, NO and NO₂). These oxides are produced during combustion, especially combustion at high temperatures. The removal technology of NO_x is used universally by the Selective Catalytic Reduction (SCR) technique. The NO_x reduction process includes the injection of ammonia (NH₃) into flue gas stream in the presence of catalyst where the NO_x reacts selectivity with NH₃ and is converted into nitrogen (N₂) and water (H₂O). The main reaction is expressed as follows.



The flue gas is then passed through continuous monitoring equipment (CEM) before it is discharged to the atmosphere. CEM is a technique for the continuous measurement of pollutants emitted into the atmosphere in exhaust gases from combustion or industrial processes. The EPA has established requirements for the continuous monitoring of SO₂, volumetric flow, NO_x, diluent gas, and opacity, for facilities regulated under the Acid Rain Program. In addition, CEM is instrumental in ensuring that procedures for the mandated reductions of SO₂ and NO_x are followed. After it is monitored by CEM the exhaust gas is then allowed to exit to the atmosphere through an exhaust stack at temperature between 300F - 400 DEG F range.

High pressure steam at 500 PSIG and 650 DEG F is fed to an extraction condensing steam turbine at a rate of 100,000 PPH. As it passes through the turbine discs or blades, the steam is then extracted at 80 PSIG saturated steam for the use in the feedstock conversion plant. In the condensing cycle, the steam leaves the turbine and flows toward a condenser where it is re-converted into water and directed to a hot well and then to the boiler as feed water.

Meanwhile, the steam energy causes the turbine shaft to spin, which drives an electrical generator. The potential electric power generated may be, for example, between about 4 to 7 Megawatts.

The electric generator works on the principle of electromagnetic induction, which creates a voltage difference between the two ends of a wire or electrical conductor, which in turn causes electric charges to flow, thus generating electric current.

The electric current is fed to electric station switchgear backed up by an uninterruptible power supply, the electric current approx. 4000 volts is stepped-down through a transformer to 480 volts for use in the feedstock conversion plant. Excess electric current at 4000 volts is stepped-up via step-up transformer to 113,000 V for grid export.

An example of flow of fuel (e.g. residues, co-products, waste, impurities from various processes) to a cogeneration facility **200** and flow of energy generated from these fuels into a feedstock conversion process is shown in FIG. 2. The figure shows a cogeneration plant **200** (e.g., part of a larger bioprocessing plan) surrounded by various processes. The double arrows indicate movement of energy from the cogeneration plant to the various processes, and material from the processes to the cogeneration plant. Single arrows indicate a possible flow for the processes in the biomass processing plant.

In biomass processing, a comminution step may be advantageous, and can be an initial step in the biomass conversion plant. Comminuting biomass **210**, e.g., with one or more of the mechanical treatments discussed herein, can result in fine particles that are difficult to process in subsequent processing steps. Rather than discarding these fines, these can be input into the cogeneration process, for example, as a drying agent. Comminution also requires a considerable input of energy, some or all of which can be obtained from the cogeneration process.

Other pre-processing steps, e.g., steps used to reduce the recalcitrance of the biomass material **220**, may also generate residues that are unusable for the primary processes (e.g., Process 1, **230** or Process 2, **240**) but that can be input into the cogeneration process. For example, pre-processing can produce lignin, feedstock that has been deleteriously affected by the preprocessing (e.g., decomposed, made toxic, contaminated) and/or fines (e.g., produced during pneumatic/vibratory conveying and collected by a bag house or by other screening). The pre-processing also require energy, e.g., steam heat and/or electricity (e.g., for various power sources such as irradiation equipment and conveying equipment).

Primary Process 1, **230** (e.g., saccharification) produce a significant amount of solid residues, containing for example lignin, minerals, proteins, fats, enzymes, denatured enzymes, and other components. In addition to being used, for example, as

feed or nutrients for animals, plants or organisms, these residues, or a subset or portion of these residues, can be input to the cogeneration process. The energy from the cogeneration process can be used in the saccharification process. For example, steam or heat generated from resistive heating can be used to maintain a desired temperature of a
5 saccharifying mixture during saccharification. The energy can also be used for mechanical mixing, *e.g.*, using jet mixers and/or other mixers as described herein.

Primary Process 2, **240** (*e.g.*, fermentation) generates solid residues containing, for example, in addition to the materials found in saccharified residues, yeast cells, bacterial cells, fungal cells or mixtures of these cells. In addition to uses as, for example
10 nutrients for animals and organisms, the residues can be input to the cogeneration process and the energy utilized to maintain the desired fermentation temperature.

The saccharified and optionally fermented biomass material as described above can include less than 35 percent by weight carbohydrates, such as less than 33, 30, 25, 20, 18, 16, 14, 12, 10 or even less than 8 percent on a dry basis. Carbohydrate depleted
15 biomass can have a high heat content. For example, as described below dry lignin can have an energy content of between about 11,000 and 12,500 BTU per pound, compared to 7,000 and 8,000 BTU per pound of holocellulose.

Further processing, including isolation/concentration and or purification **250** of products and or intermediates can also generate by by-products (*e.g.*, waste) that can be
20 used as fuel for the co-generation plant. For example, steps such as by distillation, filtration and centrifugation (*e.g.*, a decanter centrifuge, a continuous centrifuge) can all generate solids with high energy contents. These processes also require energy, for example heating for distillation, and electricity for centrifugation, that can be tapped from the co-generation plant.

25 Post processing **260** (*e.g.*, packaging, distribution and/or storage) require energy for various processes. For example electricity may be needed for packing equipment, conveyors (*e.g.*, for distribution), and climate control (*e.g.*, for storage). These processes can also generate some waste, for example expired products, packaging waste that can be used as a contribution to fuel the co-generation plant.

30 The isolated solids/residues can include inorganic materials, for example including diatomaceous earth, such as celite, a glass, such as a silica glass, such as volcanic amorphous glass, such as perlite, a cellulosic or lignocellulosic material, silica, alumina, zeolite, sand or mixtures of any of these filter aids. For example, filter aids used

during Rotary Vacuum Drum Filtration (RVDF) for removing solid residues after saccharification, fermentation and/or distillation.

Some more details and reiterations of processes for treating a feedstock that can be utilized, for example, with the embodiments already discussed above, or in other
5 embodiments, are described in the following disclosures. In particular, the residues discussed herein can be generated, for example, as a result of the feedstock treatment and processing steps described in the following sections.

SYSTEMS FOR TREATING A FEEDSTOCK

10

Processes for conversion of a feedstock to sugars and other products, in which the methods discussed above may be used (*e.g.*, wherein the feedstock for co-generation can be produced and/or wherein the energy produced by co-gen can be utilized), can include, for example, optionally physically pre-treating the feedstock, *e.g.*, to reduce its size,
15 before and/or after this treatment, optionally treating the feedstock to reduce its recalcitrance (*e.g.*, by irradiation), and saccharifying the feedstock to form a sugar solution. Saccharification can be performed by mixing a dispersion of the feedstock in a liquid medium, *e.g.*, water with an enzyme, as will be discussed in detail below. During or after saccharification, the mixture (if saccharification is to be partially or completely
20 performed en route) or solution can be transported, *e.g.*, by pipeline, railcar, truck or barge, to a manufacturing plant. At the plant, the solution can be bioprocessed, *e.g.*, fermented, to produce a desired product or intermediate, which can then be processed further, *e.g.*, by distillation. The individual processing steps, materials used and examples of products and intermediates that may be formed will be described in detail
25 below

RADIATION TREATMENT

The feedstock can be treated with radiation to modify its structure to reduce its
30 recalcitrance. Such treatment can, for example, reduce the average molecular weight of the feedstock, change the crystalline structure of the feedstock, and/or increase the surface area and/or porosity of the feedstock. Radiation can be by, for example electron beam, ion beam, 100 nm to 280 nm ultraviolet (UV) light, gamma or X-ray radiation. Radiation treatments and systems for treatments are discussed in U.S. Patent 8,142,620,

and U.S. Patent Application Series No. 12/417,731, the entire disclosures of which are incorporated herein by reference.

Each form of radiation ionizes the biomass via particular interactions, as determined by the energy of the radiation. Heavy charged particles primarily ionize matter via Coulomb scattering; furthermore, these interactions produce energetic electrons that may further ionize matter. Alpha particles are identical to the nucleus of a helium atom and are produced by the alpha decay of various radioactive nuclei, such as isotopes of bismuth, polonium, astatine, radon, francium, radium, several actinides, such as actinium, thorium, uranium, neptunium, curium, californium, americium, and plutonium. Electrons interact via Coulomb scattering and bremsstrahlung radiation produced by changes in the velocity of electrons.

When particles are utilized, they can be neutral (uncharged), positively charged or negatively charged. When charged, the charged particles can bear a single positive or negative charge, or multiple charges, *e.g.*, one, two, three or even four or more charges. In instances in which chain scission is desired to change the molecular structure of the carbohydrate containing material, positively charged particles may be desirable, in part, due to their acidic nature. When particles are utilized, the particles can have the mass of a resting electron, or greater, *e.g.*, 500, 1000, 1500, or 2000 or more times the mass of a resting electron. For example, the particles can have a mass of from about 1 atomic unit to about 150 atomic units, *e.g.*, from about 1 atomic unit to about 50 atomic units, or from about 1 to about 25, *e.g.*, 1, 2, 3, 4, 5, 10, 12 or 15 atomic units.

Gamma radiation has the advantage of a significant penetration depth into a variety of material in the sample.

In embodiments in which the irradiating is performed with electromagnetic radiation, the electromagnetic radiation can have, *e.g.*, energy per photon (in electron volts) of greater than 10^2 eV, *e.g.*, greater than 10^3 , 10^4 , 10^5 , 10^6 , or even greater than 10^7 eV. In some embodiments, the electromagnetic radiation has energy per photon of between 10^4 and 10^7 , *e.g.*, between 10^5 and 10^6 eV. The electromagnetic radiation can have a frequency of, *e.g.*, greater than 10^{16} Hz, greater than 10^{17} Hz, 10^{18} , 10^{19} , 10^{20} , or even greater than 10^{21} Hz. In some embodiments, the electromagnetic radiation has a frequency of between 10^{18} and 10^{22} Hz, *e.g.*, between 10^{19} to 10^{21} Hz.

Electron bombardment may be performed using an electron beam device that has a nominal energy of less than 10 MeV, *e.g.*, less than 7 MeV, less than 5 MeV, or less

than 2 MeV, *e.g.*, from about 0.5 to 1.5 MeV, from about 0.8 to 1.8 MeV, or from about 0.7 to 1 MeV. In some implementations the nominal energy is about 500 to 800 keV.

The electron beam may have a relatively high total beam power (the combined beam power of all accelerating heads, or, if multiple accelerators are used, of all
5 accelerators and all heads), *e.g.*, at least 25 kW, *e.g.*, at least 30, 40, 50, 60, 65, 70, 80, 100, 125, or 150 kW. In some cases, the power is even as high as 500 kW, 750 kW, or even 1000 kW or more. In some cases the electron beam has a beam power of 1200 kW or more, *e.g.*, 1400, 1600, 1800, or even 3000 kW.

This high total beam power is usually achieved by utilizing multiple accelerating
10 heads. For example, the electron beam device may include two, four, or more accelerating heads. The use of multiple heads, each of which has a relatively low beam power, prevents excessive temperature rise in the material, thereby preventing burning of the material, and also increases the uniformity of the dose through the thickness of the layer of material.

15 It is generally preferred that the bed of biomass material has a relatively uniform thickness. In some embodiments the thickness is less than about 1 inch (*e.g.*, less than about 0.75 inches, less than about 0.5 inches, less than about 0.25 inches, less than about 0.1 inches, between about 0.1 and 1 inch, between about 0.2 and 0.3 inches).

It is desirable to treat the material as quickly as possible. In general, it is
20 preferred that treatment be performed at a dose rate of greater than about 0.25 Mrad per second, *e.g.*, greater than about 0.5, 0.75, 1, 1.5, 2, 5, 7, 10, 12, 15, or even greater than about 20 Mrad per second, *e.g.*, about 0.25 to 2 Mrad per second. Higher dose rates allow a higher throughput for a target (*e.g.*, the desired) dose. Higher dose rates generally require higher line speeds, to avoid thermal decomposition of the material. In one
25 implementation, the accelerator is set for 3 MeV, 50 mA beam current, and the line speed is 24 feet/minute, for a sample thickness of about 20 mm (*e.g.*, comminuted corn cob material with a bulk density of 0.5 g/cm³).

In some embodiments, electron bombardment is performed until the material receives a total dose of at least 0.1 Mrad, 0.25 Mrad, 1 Mrad, 5 Mrad, *e.g.*, at least 10,
30 20, 30 or at least 40 Mrad. In some embodiments, the treatment is performed until the material receives a dose of from about 10 Mrad to about 50 Mrad, *e.g.*, from about 20 Mrad to about 40 Mrad, or from about 25 Mrad to about 30 Mrad. In some implementations, a total dose of 25 to 35 Mrad is preferred, applied ideally over a couple of passes, *e.g.*, at 5 Mrad/pass with each pass being applied for about one second.

Cooling methods, systems and equipment can be used before, during, after and in between radiations, for example utilizing a cooling screw conveyor and/or a cooled vibratory conveyor.

Using multiple heads as discussed above, the material can be treated in multiple passes, for example, two passes at 10 to 20 Mrad/pass, *e.g.*, 12 to 18 Mrad/pass, separated by a few seconds of cool-down, or three passes of 7 to 12 Mrad/pass, *e.g.*, 5 to 20 Mrad/pass, 10 to 40 Mrad/pass, 9 to 11 Mrad/pass. As discussed herein, treating the material with several relatively low doses, rather than one high dose, tends to prevent overheating of the material and also increases dose uniformity through the thickness of the material. In some implementations, the material is stirred or otherwise mixed during or after each pass and then smoothed into a uniform layer again before the next pass, to further enhance treatment uniformity.

In some embodiments, electrons are accelerated to, for example, a speed of greater than 75 percent of the speed of light, *e.g.*, greater than 85, 90, 95, or 99 percent of the speed of light.

In some embodiments, any processing described herein occurs on lignocellulosic material that remains dry as acquired or that has been dried, *e.g.*, using heat and/or reduced pressure. For example, in some embodiments, the cellulosic and/or lignocellulosic material has less than about 25 wt. % retained water, measured at 25°C and at fifty percent relative humidity (*e.g.*, less than about 20 wt.%, less than about 15 wt.%, less than about 14 wt.%, less than about 13 wt.%, less than about 12 wt.%, less than about 10 wt.%, less than about 9 wt.%, less than about 8 wt.%, less than about 7 wt.%, less than about 6 wt.%, less than about 5 wt.%, less than about 4 wt.%, less than about 3 wt.%, less than about 2 wt.%, less than about 1 wt.%, or less than about 0.5 wt.%.

In some embodiments, two or more ionizing sources can be used, such as two or more electron sources. For example, samples can be treated, in any order, with a beam of electrons, followed by gamma radiation and UV light having wavelengths from about 100 nm to about 280 nm. In some embodiments, samples are treated with three ionizing radiation sources, such as a beam of electrons, gamma radiation, and energetic UV light. The biomass is conveyed through the treatment zone where it can be bombarded with electrons.

It may be advantageous to repeat the treatment to more thoroughly reduce the recalcitrance of the biomass and/or further modify the biomass. In particular the process

parameters can be adjusted after a first (*e.g.*, second, third, fourth or more) pass depending on the recalcitrance of the material. In some embodiments, a conveyor can be used which includes a circular system where the biomass is conveyed multiple times through the various processes described above. In some other embodiments, multiple
5 treatment devices (*e.g.*, electron beam generators) are used to treat the biomass multiple (*e.g.*, 2, 3, 4 or more) times. In yet other embodiments, a single electron beam generator may be the source of multiple beams (*e.g.*, 2, 3, 4 or more beams) that can be used for treatment of the biomass.

The effectiveness in changing the molecular/supramolecular structure and/or
10 reducing the recalcitrance of the carbohydrate-containing biomass depends on the electron energy used and the dose applied, while exposure time depends on the power and dose. In some embodiments, the dose rate and total dose are adjusted so as not to destroy (*e.g.*, char or burn) the biomass material. For example, the carbohydrates should not be damaged in the processing so that they can be released from the biomass intact,
15 *e.g.* as monomeric sugars.

In some embodiments, the treatment (with any electron source or a combination of sources) is performed until the material receives a dose of at least about 0.05 Mrad, *e.g.*, at least about 0.1, 0.25, 0.5, 0.75, 1.0, 2.5, 5.0, 7.5, 10.0, 15, 20, 25, 30, 40, 50, 60, 70, 80, 90, 100, 125, 150, 175, or 200 Mrad. In some embodiments, the treatment is
20 performed until the material receives a dose of between 0.1-100 Mrad, 1-200, 5-200, 10-200, 5-150, 50-150 Mrad, 5-100, 5-50, 5-40, 10-50, 10-75, 15-50, 20-35 Mrad.

In some embodiments, relatively low doses of radiation are utilized, *e.g.*, to increase the molecular weight of a cellulosic or lignocellulosic material (with any radiation source or a combination of sources described herein). For example, a dose of at
25 least about 0.05 Mrad, *e.g.*, at least about 0.1 Mrad or at least about 0.25, 0.5, 0.75, 1.0, 1.5, 2.0, 2.5, 3.0, 3.5, 4.0, or at least about 5.0 Mrad. In some embodiments, the irradiation is performed until the material receives a dose of between 0.1Mrad and 2.0 Mrad, *e.g.*, between 0.5rad and 4.0 Mrad or between 1.0 Mrad and 3.0 Mrad.

It also can be desirable to irradiate from multiple directions, simultaneously or
30 sequentially, in order to achieve a desired degree of penetration of radiation into the material. For example, depending on the density and moisture content of the material, such as wood, and the type of radiation source used (*e.g.*, gamma or electron beam), the maximum penetration of radiation into the material may be only about 0.75 inch. In such a cases, a thicker section (up to 1.5 inch) can be irradiated by first irradiating the material

from one side, and then turning the material over and irradiating from the other side. Irradiation from multiple directions can be particularly useful with electron beam radiation, which irradiates faster than gamma radiation but typically does not achieve as great a penetration depth.

5

RADIATION OPAQUE MATERIALS

The invention can include processing the material (*e.g.*, for some of the processing steps) in a vault and/or bunker that is constructed using radiation opaque materials. In some implementations, the radiation opaque materials are selected to be capable of shielding the components from X-rays with high energy (short wavelength), which can penetrate many materials. One important factor in designing a radiation shielding enclosure is the attenuation length of the materials used, which will determine the required thickness for a particular material, blend of materials, or layered structure. The attenuation length is the penetration distance at which the radiation is reduced to approximately $1/e$ (e = Euler's number) times that of the incident radiation. Although virtually all materials are radiation opaque if thick enough, materials containing a high compositional percentage (*e.g.*, density) of elements that have a high Z value (atomic number) have a shorter radiation attenuation length and thus if such materials are used a thinner, lighter shielding can be provided. Examples of high Z value materials that are used in radiation shielding are tantalum and lead. Another important parameter in radiation shielding is the halving distance, which is the thickness of a particular material that will reduce gamma ray intensity by 50%. As an example for X-ray radiation with an energy of 0.1 MeV the halving thickness is about 15.1 mm for concrete and about 2.7 mm for lead, while with an X-ray energy of 1 MeV the halving thickness for concrete is about 44.45 mm and for lead is about 7.9 mm. Radiation opaque materials can be materials that are thick or thin so long as they can reduce the radiation that passes through to the other side. Thus, if it is desired that a particular enclosure have a low wall thickness, *e.g.*, for light weight or due to size constraints, the material chosen should have a sufficient Z value and/or attenuation length so that its halving length is less than or equal to the desired wall thickness of the enclosure.

In some cases, the radiation opaque material may be a layered material, for example having a layer of a higher Z value material, to provide good shielding, and a

layer of a lower Z value material to provide other properties (*e.g.*, structural integrity, impact resistance, etc.). In some cases, the layered material may be a "graded-Z" laminate, *e.g.*, including a laminate in which the layers provide a gradient from high-Z through successively lower-Z elements. In some cases the radiation opaque materials can be interlocking blocks, for example, lead and/or concrete blocks can be supplied by NELCO Worldwide (Burlington, MA), and reconfigurable vaults can be utilized.

A radiation opaque material can reduce the radiation passing through a structure (*e.g.*, a wall, door, ceiling, enclosure, a series of these or combinations of these) formed of the material by about at least about 10 %, (*e.g.*, at least about 20%, at least about 30%, at least about 40%, at least about 50%, at least about 60%, at least about 70%, at least about 80%, at least about 90%, at least about 95%, at least about 96%, at least about 97%, at least about 98%, at least about 99%, at least about 99.9%, at least about 99.99%, at least about 99.999%) as compared to the incident radiation. Therefore, an enclosure made of a radiation opaque material can reduce the exposure of equipment/system/components by the same amount. Radiation opaque materials can include stainless steel, metals with Z values above 25 (*e.g.*, lead, iron), concrete, dirt, sand and combinations thereof. Radiation opaque materials can include a barrier in the direction of the incident radiation of at least about 1mm (*e.g.*, 5 mm, 10mm, 5 cm, 10 cm, 100cm, 1m, 10m).

RADIATION SOURCES

The type of radiation determines the kinds of radiation sources used as well as the radiation devices and associated equipment. The methods, systems and equipment described herein, for example for treating materials with radiation, can utilized sources as described herein as well as any other useful source.

Sources of gamma rays include radioactive nuclei, such as isotopes of cobalt, calcium, technetium, chromium, gallium, indium, iodine, iron, krypton, samarium, selenium, sodium, thallium, and xenon.

Sources of X-rays include electron beam collision with metal targets, such as tungsten or molybdenum or alloys, or compact light sources, such as those produced commercially by Lyncean.

Alpha particles are identical to the nucleus of a helium atom and are produced by the alpha decay of various radioactive nuclei, such as isotopes of bismuth, polonium,

astatine, radon, francium, radium, several actinides, such as actinium, thorium, uranium, neptunium, curium, californium, americium, and plutonium.

Sources for ultraviolet radiation include deuterium or cadmium lamps.

Sources for infrared radiation include sapphire, zinc, or selenide window ceramic
5 lamps.

Sources for microwaves include klystrons, Slevin type RF sources, or atom beam sources that employ hydrogen, oxygen, or nitrogen gases.

Accelerators used to accelerate the particles (e.g., electrons or ions) can be DC (e.g., electrostatic DC or electrodynamic DC), RF linear, magnetic induction linear or
10 continuous wave. For example, various irradiating devices may be used in the methods disclosed herein, including field ionization sources, electrostatic ion separators, field ionization generators, thermionic emission sources, microwave discharge ion sources, recirculating or static accelerators, dynamic linear accelerators, van de Graaff accelerators, Cockroft Walton accelerators (e.g., PELLETRON® accelerators), LINACS,
15 Dynamitrons (e.g., DYNAMITRON® accelerators), cyclotrons, synchrotrons, betatrons, transformer-type accelerators, microtrons, plasma generators, cascade accelerators, and folded tandem accelerators. For example, cyclotron type accelerators are available from IBA, Belgium, such as the RHODOTRON™ system, while DC type accelerators are available from RDI, now IBA Industrial, such as the DYNAMITRON®. Other suitable
20 accelerator systems include, for example: DC insulated core transformer (ICT) type systems, available from Nissin High Voltage, Japan; S-band LINACs, available from L3-PSD (USA), Linac Systems (France), Mevex (Canada), and Mitsubishi Heavy Industries (Japan); L-band LINACs, available from Iotron Industries (Canada); and ILU-based accelerators, available from Budker Laboratories (Russia). Ions and ion accelerators are
25 discussed in Introductory Nuclear Physics, Kenneth S. Krane, John Wiley & Sons, Inc. (1988), Krsto Prelec, FIZIKA B 6 (1997) 4, 177–206, Chu, William T., “Overview of Light-Ion Beam Therapy”, Columbus-Ohio, ICRU-IAEA Meeting, 18-20 March 2006, Iwata, Y. et al., “Alternating-Phase-Focused IH-DTL for Heavy-Ion Medical Accelerators”, Proceedings of EPAC 2006, Edinburgh, Scotland, and Leitner, C.M. et
30 al., “Status of the Superconducting ECR Ion Source Venus”, Proceedings of EPAC 2000, Vienna, Austria. Some particle accelerators and their uses are disclosed, for example, in U.S. Pat. No. 7,931,784 to Medoff, the complete disclosure of which is incorporated herein by reference.

Electrons may be produced by radioactive nuclei that undergo beta decay, such as isotopes of iodine, cesium, technetium, and iridium. Alternatively, an electron gun can be used as an electron source via thermionic emission and accelerated through an accelerating potential. An electron gun generates electrons, which are then accelerated
5 through a large potential (*e.g.*, greater than about 500 thousand, greater than about 1million, greater than about 2 million, greater than about 5 million, greater than about 6 million, greater than about 7 million, greater than about 8 million, greater than about 9 million, or even greater than 10 million volts) and then scanned magnetically in the x-y plane, where the electrons are initially accelerated in the z direction down the accelerator tube and extracted through a foil window. Scanning the electron beams is useful for
10 increasing the irradiation surface when irradiating materials, *e.g.*, a biomass, that is conveyed through the scanned beam. Scanning the electron beam also distributes the thermal load homogenously on the window and helps reduce the foil window rupture due to local heating by the electron beam. Window foil rupture is a cause of significant
15 down-time due to subsequent necessary repairs and re-starting the electron gun.

Various other irradiating devices may be used in the methods disclosed herein, including field ionization sources, electrostatic ion separators, field ionization generators, thermionic emission sources, microwave discharge ion sources, recirculating or static accelerators, dynamic linear accelerators, van de Graaff accelerators, and folded tandem
20 accelerators. Such devices are disclosed, for example, in U.S. Pat. No. 7,931,784 to Medoff, the complete disclosure of which is incorporated herein by reference.

A beam of electrons can be used as the radiation source. A beam of electrons has the advantages of high dose rates (*e.g.*, 1, 5, or even 10 Mrad per second), high throughput, less containment, and less confinement equipment. Electron beams can also
25 have high electrical efficiency (*e.g.*, 80%), allowing for lower energy usage relative to other radiation methods, which can translate into a lower cost of operation and lower greenhouse gas emissions corresponding to the smaller amount of energy used. Electron beams can be generated, *e.g.*, by electrostatic generators, cascade generators, transformer generators, low energy accelerators with a scanning system, low energy accelerators with
30 a linear cathode, linear accelerators, and pulsed accelerators.

Electrons can also be more efficient at causing changes in the molecular structure of carbohydrate-containing materials, for example, by the mechanism of chain scission. In addition, electrons having energies of 0.5-10 MeV can penetrate low density materials, such as the biomass materials described herein, *e.g.*, materials having a bulk

density of less than 0.5 g/cm^3 , and a depth of 0.3-10 cm. Electrons as an ionizing radiation source can be useful, *e.g.*, for relatively thin piles, layers or beds of materials, *e.g.*, less than about 0.5 inch, *e.g.*, less than about 0.4 inch, 0.3 inch, 0.25 inch, or less than about 0.1 inch. In some embodiments, the energy of each electron of the electron beam is from about 0.3 MeV to about 2.0 MeV (million electron volts), *e.g.*, from about 0.5 MeV to about 1.5 MeV, or from about 0.7 MeV to about 1.25 MeV. Methods of irradiating materials are discussed in U.S. Pat. App. Pub. 2012/0100577 A1, filed October 18, 2011, the entire disclosure of which is herein incorporated by reference.

Electron beam irradiation devices may be procured commercially or built. For example, elements or components such inductors, capacitors, casings, power sources, cables, wiring, voltage control systems, current control elements, insulating material, microcontrollers and cooling equipment can be purchased and assembled into a device. Optionally, a commercial device can be modified and/or adapted. For example, devices and components can be purchased from any of the commercial sources described herein including Ion Beam Applications (Louvain-la-Neuve, Belgium), Wasik Associates Inc. (Dracut, MA), NHV Corporation (Japan), the Titan Corporation (San Diego, CA), Vivirad High Voltage Corp (Billerica, MA) and/or Budker Laboratories (Russia). Typical electron energies can be 0.5 MeV, 1 MeV, 2 MeV, 4.5 MeV, 7.5 MeV, or 10 MeV. Typical electron beam irradiation device power can be 1 kW, 5 kW, 10 kW, 20 kW, 50 kW, 60 kW, 70 kW, 80 kW, 90 kW, 100 kW, 125 kW, 150 kW, 175 kW, 200 kW, 250 kW, 300 kW, 350 kW, 400 kW, 450 kW, 500 kW, 600 kW, 700 kW, 800 kW, 900 kW or even 1000 kW. Accelerators that can be used include NHV irradiators medium energy series EPS-500 (*e.g.*, 500 kV accelerator voltage and 65, 100 or 150 mA beam current), EPS-800 (*e.g.*, 800 kV accelerator voltage and 65 or 100 mA beam current), or EPS-1000 (*e.g.*, 1000 kV accelerator voltage and 65 or 100 mA beam current). Also, accelerators from NHV's high energy series can be used such as EPS-1500 (*e.g.*, 1500 kV accelerator voltage and 65 mA beam current), EPS-2000 (*e.g.*, 2000 kV accelerator voltage and 50 mA beam current), EPS-3000 (*e.g.*, 3000 kV accelerator voltage and 50 mA beam current) and EPS-5000 (*e.g.*, 5000 and 30 mA beam current).

Tradeoffs in considering electron beam irradiation device power specifications include cost to operate, capital costs, depreciation, and device footprint. Tradeoffs in considering exposure dose levels of electron beam irradiation would be energy costs and environment, safety, and health (ESH) concerns. Typically, generators are housed in a

vault, *e.g.*, of lead or concrete, especially for production from X-rays that are generated in the process. Tradeoffs in considering electron energies include energy costs.

The electron beam irradiation device can produce either a fixed beam or a scanning beam. A scanning beam may be advantageous with large scan sweep length
5 and high scan speeds, as this would effectively replace a large, fixed beam width. Further, available sweep widths of 0.5 m, 1 m, 2 m or more are available. The scanning beam is preferred in most embodiments described herein because of the larger scan width and reduced possibility of local heating and failure of the windows.

10

ELECTRON GUNS – WINDOWS

The extraction system for an electron accelerator can include two window foils. The cooling gas in the two foil window extraction system can be a purge gas or a mixture, for example air, or a pure gas. In one embodiment the gas is an inert gas such
15 as nitrogen, argon, helium and or carbon dioxide. It is preferred to use a gas rather than a liquid since energy losses to the electron beam are minimized. Mixtures of pure gas can also be used, either pre-mixed or mixed in line prior to impinging on the windows or in the space between the windows. The cooling gas can be cooled, for example, by using a heat exchange system (*e.g.*, a chiller) and/or by using boil off from a condensed gas (*e.g.*,
20 liquid nitrogen, liquid helium). Window foils are described in PCT/US2013/64332 filed October 10, 2013 the full disclosure of which is incorporated by reference herein.

HEATING AND THROUGHPUT DURING RADIATION TREATMENT

25 Several processes can occur in biomass when electrons from an electron beam interact with matter in inelastic collisions. For example, ionization of the material, chain scission of polymers in the material, cross linking of polymers in the material, oxidation of the material, generation of X-rays (“Bremsstrahlung”) and vibrational excitation of molecules (*e.g.*, phonon generation). Without being bound to a particular mechanism, the
30 reduction in recalcitrance can be due to several of these inelastic collision effects, for example ionization, chain scission of polymers, oxidation and phonon generation. Some of the effects (*e.g.*, especially X-ray generation), necessitate shielding and engineering barriers, for example, enclosing the irradiation processes in a concrete (or other radiation opaque material) vault. Another effect of irradiation, vibrational excitation, is equivalent

to heating up the sample. Heating the sample by irradiation can help in recalcitrance reduction, but excessive heating can destroy the material, as will be explained below.

The adiabatic temperature rise (ΔT) from adsorption of ionizing radiation is given by the equation: $\Delta T = D/C_p$: where D is the average dose in kGy, C_p is the heat capacity in J/g $^{\circ}\text{C}$, and ΔT is the change in temperature in $^{\circ}\text{C}$. A typical dry biomass material will have a heat capacity close to 2. Wet biomass will have a higher heat capacity dependent on the amount of water since the heat capacity of water is very high (4.19 J/g $^{\circ}\text{C}$). Metals have much lower heat capacities, for example 304 stainless steel has a heat capacity of 0.5 J/g $^{\circ}\text{C}$. The temperature change due to the instant adsorption of radiation in a biomass and stainless steel for various doses of radiation is shown in Table 1. In practice, the higher temperatures cause decomposition of the biomass leading to extreme deviation from theory.

Table 1: Calculated Temperature increase for biomass and stainless steel.

Dose (Mrad)	Estimated Biomass ΔT ($^{\circ}\text{C}$)	Steel ΔT ($^{\circ}\text{C}$)
10	50	200
50	250 (decomposed)	1000
100	500 (decomposed)	2000
150	750 (decomposed)	3000
200	1000 (decomposed)	4000

15

High temperatures can destroy and or modify the biopolymers in biomass so that the polymers (*e.g.*, cellulose) are unsuitable for further processing. A biomass subjected to high temperatures can become dark, sticky and give off odors indicating decomposition. The stickiness can even make the material hard to convey. The odors can be unpleasant and be a safety issue. In fact, keeping the biomass below about 200 $^{\circ}\text{C}$ has been found to be beneficial in the processes described herein (*e.g.*, below about 190 $^{\circ}\text{C}$, below about 180 $^{\circ}\text{C}$, below about 170 $^{\circ}\text{C}$, below about 160 $^{\circ}\text{C}$, below about 150 $^{\circ}\text{C}$, below about 140 $^{\circ}\text{C}$, below about 130 $^{\circ}\text{C}$, below about 120 $^{\circ}\text{C}$, below about 110 $^{\circ}\text{C}$, between about 60 $^{\circ}\text{C}$ and 180 $^{\circ}\text{C}$, between about 60 $^{\circ}\text{C}$ and 160 $^{\circ}\text{C}$, between about 60 $^{\circ}\text{C}$ and 150 $^{\circ}\text{C}$, between about 60 $^{\circ}\text{C}$ and 140 $^{\circ}\text{C}$, between about 60 $^{\circ}\text{C}$ and 130 $^{\circ}\text{C}$, between about 60 $^{\circ}\text{C}$ and 120 $^{\circ}\text{C}$, between about 80 $^{\circ}\text{C}$ and 180 $^{\circ}\text{C}$, between about 100 $^{\circ}\text{C}$ and 180 $^{\circ}\text{C}$, between about 120 $^{\circ}\text{C}$ and 180 $^{\circ}\text{C}$, between about 140 $^{\circ}\text{C}$ and 180 $^{\circ}\text{C}$, between about 160 $^{\circ}\text{C}$ and 180 $^{\circ}\text{C}$, between about 100 $^{\circ}\text{C}$ and 140 $^{\circ}\text{C}$, between about 80 $^{\circ}\text{C}$ and 120 $^{\circ}\text{C}$).

25

It has been found that irradiation above about 10 Mrad is desirable for the processes described herein (*e.g.*, reduction of recalcitrance). A high throughput is also desirable so that the irradiation does not become a bottle neck in processing the biomass. The treatment is governed by a Dose rate equation: $M = FP/D \cdot \text{time}$, where M is the mass of irradiated material (Kg), F is the fraction of power that is adsorbed (unit less), P is the emitted power ($\text{kW} = \text{Voltage in MeV} \times \text{Current in mA}$), time is the treatment time (sec) and D is the adsorbed dose (kGy). In an exemplary process where the fraction of adsorbed power is fixed, the Power emitted is constant and a set dosage is desired, the throughput (*e.g.*, M, the biomass processed) can be increased by increasing the irradiation time. However, increasing the irradiation time without allowing the material to cool, can excessively heat the material as exemplified by the calculations shown above. Since biomass has a low thermal conductivity (less than about $0.1 \text{ Wm}^{-1}\text{K}^{-1}$), heat dissipation is slow, unlike, for example metals (greater than about $10 \text{ Wm}^{-1}\text{K}^{-1}$) which can dissipate energy quickly as long as there is a heat sink to transfer the energy to.

ELECTRON GUNS – BEAM STOPS

In some embodiments the systems and methods include a beam stop (*e.g.*, a shutter). For example, the beam stop can be used to quickly stop or reduce the irradiation of material without powering down the electron beam device. Alternatively the beam stop can be used while powering up the electron beam, *e.g.*, the beam stop can stop the electron beam until a beam current of a desired level is achieved. The beam stop can be placed between the primary foil window and a secondary foil window. For example the beam stop can be mounted so that it is movable, that is, so that it can be moved into and out of the beam path. Even partial coverage of the beam can be used, for example, to control the dose of irradiation. The beam stop can be mounted to the floor, to a conveyor for the biomass, to a wall, to the radiation device (*e.g.*, at the scan horn), or to any structural support. Preferably the beam stop is fixed in relation to the scan horn so that the beam can be effectively controlled by the beam stop. The beam stop can incorporate a hinge, a rail, wheels, slots, or other means allowing for its operation in moving into and out of the beam. The beam stop can be made of any material that will stop at least 5% of the electrons, *e.g.*, at least 10%, 20%, 30%, 40%, 50%, 60%, 70%, at

least 80%, 85%, 90%, 91%, 92%, 93%, 94%, 95%, 96%, 97%, 98%, 99% or even about 100% of the electrons.

The beam stop can be made of a metal including, but not limited to, stainless steel, lead, iron, molybdenum, silver, gold, titanium, aluminum, tin, or alloys of these, or
5 laminates (layered materials) made with such metals (*e.g.*, metal-coated ceramic, metal-coated polymer, metal-coated composite, multilayered metal materials).

The beam stop can be cooled, for example, with a cooling fluid such as an aqueous solution or a gas. The beam stop can be partially or completely hollow, for example, with cavities. Interior spaces of the beam stop can be used for cooling fluids
10 and gases. The beam stop can be of any shape, including flat, curved, round, oval, square, rectangular, beveled and wedged shapes.

The beam stop can have perforations so as to allow some electrons through, thus controlling (*e.g.*, reducing) the levels of radiation across the whole area of the window, or in specific regions of the window. The beam stop can be a mesh formed, for example,
15 from fibers or wires. Multiple beam stops can be used, together or independently, to control the irradiation. The beam stop can be remotely controlled, *e.g.*, by radio signal or hard wired to a motor for moving the beam into or out of position.

BEAM DUMPS

20

The embodiments disclosed herein can also include a beam dump when utilizing a radiation treatment. A beam dump's purpose is to safely absorb a beam of charged particles. Like a beam stop, a beam dump can be used to block the beam of charged particles. However, a beam dump is much more robust than a beam stop, and is intended
25 to block the full power of the electron beam for an extended period of time. They are often used to block the beam as the accelerator is powering up.

Beam dumps are also designed to accommodate the heat generated by such beams, and are usually made from materials such as copper, aluminum, carbon, beryllium, tungsten, or mercury. Beam dumps can be cooled, for example, using a
30 cooling fluid that can be in thermal contact with the beam dump.

BIOMASS MATERIALS

Lignocellulosic materials, such as can be used in the methods and equipment described herein include, but are not limited to, wood, particle board, forestry wastes
5 (e.g., sawdust, aspen wood, wood chips), grasses, (e.g., switchgrass, miscanthus, cord grass, reed canary grass), grain residues, (e.g., rice hulls, oat hulls, wheat chaff, barley hulls), agricultural waste (e.g., silage, canola straw, wheat straw, barley straw, oat straw, rice straw, jute, hemp, flax, bamboo, sisal, abaca, corn cobs, corn stover, soybean stover, corn fiber, alfalfa, hay, coconut hair), sugar processing residues (e.g., bagasse, beet pulp,
10 agave bagasse), algae, seaweed, manure, sewage, and mixtures of any of these.

In some cases, the lignocellulosic material includes corncobs. Ground or hammermilled corncobs can be spread in a layer of relatively uniform thickness for irradiation, and after irradiation are easy to disperse in the medium for further processing. To facilitate harvest and collection, in some cases the entire corn plant is
15 used, including the corn stalk, corn kernels, and in some cases even the root system of the plant.

Advantageously, no additional nutrients (other than a nitrogen source, e.g., urea or ammonia) are required during fermentation of corncobs or cellulosic or lignocellulosic materials containing significant amounts of corncobs.

20 Corncobs, before and after comminution, are also easier to convey and disperse, and have a lesser tendency to form explosive mixtures in air than other cellulosic or lignocellulosic materials such as hay and grasses.

Cellulosic materials include, for example, paper, paper products, paper waste, paper pulp, pigmented papers, loaded papers, coated papers, filled papers, magazines,
25 printed matter (e.g., books, catalogs, manuals, labels, calendars, greeting cards, brochures, prospectuses, newsprint), printer paper, polycoated paper, card stock, cardboard, paperboard, materials having a high α -cellulose content such as cotton, and mixtures of any of these. For example, paper products as described in U.S. App. No. 13/396,365 ("Magazine Feedstocks" by Medoff et al., filed February 14, 2012), the full
30 disclosure of which is incorporated herein by reference.

Cellulosic materials can also include lignocellulosic materials which have been partially or fully de-lignified.

In some instances other biomass materials can be utilized, for example starchy materials. Starchy materials include starch itself, *e.g.*, corn starch, wheat starch, potato starch or rice starch, a derivative of starch, or a material that includes starch, such as an edible food product or a crop. For example, the starchy material can be arracacha, buckwheat, banana, barley, cassava, kudzu, oca, sago, sorghum, regular household potatoes, sweet potato, taro, yams, or one or more beans, such as favas, lentils or peas. Blends of any two or more starchy materials are also starchy materials. Mixtures of starchy, cellulosic and or lignocellulosic materials can also be used. For example, a biomass can be an entire plant, a part of a plant or different parts of a plant, *e.g.*, a wheat plant, cotton plant, a corn plant, rice plant or a tree. The starchy materials can be treated by any of the methods described herein.

Microbial materials that can be used as feedstock can include, but are not limited to, any naturally occurring or genetically modified microorganism or organism that contains or is capable of providing a source of carbohydrates (*e.g.*, cellulose), for example, protists, *e.g.*, animal protists (*e.g.*, protozoa such as flagellates, amoeboids, ciliates, and sporozoa) and plant protists (*e.g.*, algae such as alveolates, chlorarachniophytes, cryptomonads, euglenids, glaucophytes, haptophytes, red algae, stramenopiles, and viridaplantae). Other examples include seaweed, plankton (*e.g.*, macroplankton, mesoplankton, microplankton, nanoplankton, picoplankton, and femtoplankton), phytoplankton, bacteria (*e.g.*, gram positive bacteria, gram negative bacteria, and extremophiles), yeast and/or mixtures of these. In some instances, microbial biomass can be obtained from natural sources, *e.g.*, the ocean, lakes, bodies of water, *e.g.*, salt water or fresh water, or on land. Alternatively or in addition, microbial biomass can be obtained from culture systems, *e.g.*, large scale dry and wet culture and fermentation systems.

In other embodiments, the biomass materials, such as cellulosic, starchy and lignocellulosic feedstock materials, can be obtained from transgenic microorganisms and plants that have been modified with respect to a wild type variety. Such modifications may be, for example, through the iterative steps of selection and breeding to obtain desired traits in a plant. Furthermore, the plants can have had genetic material removed, modified, silenced and/or added with respect to the wild type variety. For example, genetically modified plants can be produced by recombinant DNA methods, where genetic modifications include introducing or modifying specific genes from parental varieties, or, for example, by using transgenic breeding wherein a specific gene or genes

are introduced to a plant from a different species of plant and/or bacteria. Another way to create genetic variation is through mutation breeding wherein new alleles are artificially created from endogenous genes. The artificial genes can be created by a variety of ways including treating the plant or seeds with, for example, chemical

5 mutagens (*e.g.*, using alkylating agents, epoxides, alkaloids, peroxides, formaldehyde), irradiation (*e.g.*, X-rays, gamma rays, neutrons, beta particles, alpha particles, protons, deuterons, UV radiation) and temperature shocking or other external stressing and subsequent selection techniques. Other methods of providing modified genes is through error prone PCR and DNA shuffling followed by insertion of the desired modified DNA

10 into the desired plant or seed. Methods of introducing the desired genetic variation in the seed or plant include, for example, the use of a bacterial carrier, biolistics, calcium phosphate precipitation, electroporation, gene splicing, gene silencing, lipofection, microinjection and viral carriers. Additional genetically modified materials have been described in U.S. Application Serial No 13/396,369 filed February 14, 2012 the full

15 disclosure of which is incorporated herein by reference.

Any of the methods described herein can be practiced with mixtures of any biomass materials described herein.

OTHER MATERIALS

20

Other materials (*e.g.*, natural or synthetic materials), for example polymers, can be treated and/or made utilizing so of the methods, equipment and systems described hererin. For example, energy produced by the methods described herein can be used to process materials. For example polyethylene (*e.g.*, linear low density ethylene and high

25 density polyethylene), polystyrenes, sulfonated polystyenes, poly (vinyl chloride), polyesters (*e.g.*, nylons, DACRON™, KODEL™), polyalkylene esters, poly vinyl esters, polyamides (*e.g.*, KEVLAR™), polyethylene terephthalate, cellulose acetate, acetal, poly acrylonitrile, polycarbonates (*e.g.*, LEXAN™), acrylics [*e.g.*, poly (methyl methacrylate), poly(methyl methacrylate), polyacrylonitriles, Poly urethanes,

30 polypropylene, poly butadiene, polyisobutylene, polyacrylonitrile, polychloroprene (*e.g.* neoprene), poly(cis-1,4-isoprene) [*e.g.*, natural rubber], poly(trans-1,4-isoprene) [*e.g.*, gutta percha], phenol formaldehyde, melamine formaldehyde, epoxides, polyesters, poly amines, polycarboxylic acids, polylactic acids, polyvinyl alcohols, polyanhydrides, poly fluoro carbons (*e.g.*, TEFLON™), silicones (*e.g.*, silicone rubber), polysilanes, poly ethers

(*e.g.*, polyethylene oxide, polypropylene oxide), waxes, oils and mixtures of these . Also included are plastics, rubbers, elastomers, fibers, waxes, gels, oils, adhesives, thermoplastics, thermosets, biodegradable polymers, resins made with these polymers, other polymers, other materials and combinations thereof. The polymers can be made by any useful method including cationic polymerization, anionic polymerization, radical polymerization, metathesis polymerization, ring opening polymerization, graft polymerization, addition polymerization. In some cases the treatments disclosed herein can be used, for example, for radically initiated graft polymerization and cross linking. Composites of polymers, for example with glass, metals, biomass (*e.g.*, fibers, particles), ceramics can also be treated and/or made.

Other materials that can be treated by using the methods, systems and equipment disclosed herein are ceramic materials, minerals, metals, inorganic compounds. For example, silicon and germanium crystals, silicon nitrides, metal oxides, semiconductors, insulators, cements and or conductors.

In addition, manufactured multipart or shaped materials (*e.g.*, molded, extruded, welded, riveted, layered or combined in any way) can be treated, for example cables, pipes, boards, enclosures, integrated semiconductor chips, circuit boards, wires, tires, windows, laminated materials, gears, belts, machines, combinations of these. For example, treating a material by the methods described herein can modify the surfaces, for example, making them susceptible to further functionalization, combinations (*e.g.*, welding) and/or treatment can cross link the materials.

BIOMASS MATERIAL PREPARATION – MECHANICAL TREATMENTS

The biomass can be in a dry form (*e.g.*, as described previously), for example with less than about 35% moisture content (*e.g.*, less than about 20 %, less than about 15 %, less than about 10 %, less than about 5 %, less than about 4%, less than about 3 %, less than about 2 % or even less than about 1 %). The biomass can also be delivered in a wet state, for example as a wet solid, a slurry or a suspension with at least about 10 wt% solids (*e.g.*, at least about 20 wt.%, at least about 30 wt. %, at least about 40 wt.%, at least about 50 wt.%, at least about 60 wt.%, at least about 70 wt.%).

The processes disclosed herein can utilize low bulk density materials, for example cellulosic or lignocellulosic feedstocks that have been physically pretreated to have a bulk density of less than about 0.75 g/cm³, *e.g.*, less than about 0.7, 0.65, 0.60,

0.50, 0.35, 0.25, 0.20, 0.15, 0.10, 0.05 or less, *e.g.*, less than about 0.025 g/cm³. Bulk density is determined using ASTM D1895B. Briefly, the method involves filling a measuring cylinder of known volume with a sample and obtaining a weight of the sample. The bulk density is calculated by dividing the weight of the sample in grams by
5 the known volume of the cylinder in cubic centimeters. If desired, low bulk density materials can be densified, for example, by methods described in U.S. Pat. No. 7,971,809 published July 5, 2011, the entire disclosure of which is hereby incorporated by reference.

In some cases, the pre-treatment processing includes screening of the biomass
10 material. Screening can be through a mesh or perforated plate with a desired opening size, for example, less than about 6.35 mm (1/4 inch, 0.25 inch), (*e.g.*, less than about 3.18 mm (1/8 inch, 0.125 inch), less than about 1.59 mm (1/16 inch, 0.0625 inch), is less than about 0.79 mm (1/32 inch, 0.03125 inch), *e.g.*, less than about 0.51 mm (1/50 inch, 0.02000 inch), less than about 0.40 mm (1/64 inch, 0.015625 inch), less than about 0.23
15 mm (0.009 inch), less than about 0.20 mm (1/128 inch, 0.0078125 inch), less than about 0.18 mm (0.007 inch), less than about 0.13 mm (0.005 inch), or even less than about 0.10 mm (1/256 inch, 0.00390625 inch)). In one configuration the desired biomass falls through the perforations or screen and thus biomass larger than the perforations or screen are not irradiated. These larger materials can be re-processed, for example, by
20 comminuting, or they can simply be removed from processing. In another configuration material that is larger than the perforations is irradiated and the smaller material is removed by the screening process or recycled. In this kind of a configuration, the conveyor, such as a vibratory conveyor, itself (for example, a part of the conveyor) can be perforated or made with a mesh. For example, in one particular embodiment the
25 biomass material may be wet and the perforations or mesh allow water to drain away from the biomass before irradiation.

Screening of material can also be by a manual method, for example by an operator or mechanoid (*e.g.*, a robot equipped with a color, reflectivity or other sensor) that removes unwanted material. Screening can also be by magnetic screening wherein a
30 magnet is disposed near the conveyed material and the magnetic material is removed magnetically.

Optional pre-treatment processing can include heating the material (*e.g.*, in addition to for drying or for the purpose of drying the material). For example, a portion of a conveyor conveying the biomass or other material can be sent through a heated

zone. The heated zone can be created, for example, by IR radiation, microwaves, combustion (*e.g.*, gas, coal, oil, biomass), resistive heating and/or inductive coils. The heat can be applied from at least one side or more than one side, can be continuous or periodic and can be for only a portion of the material or all the material. For example, a
5 portion of the conveying trough can be heated by use of a heating jacket. Heating can be, for example, for the purpose of drying the material. In the case of drying the material, this can also be facilitated, with or without heating, by the movement of a gas (*e.g.*, air, oxygen, nitrogen, He, CO₂, Argon) over and/or through the biomass as it is being conveyed.

10 Optionally, pre-treatment processing can include cooling the material. Cooling material is described in U.S. Pat. No. 7,900,857 published March 8, 2011, the disclosure of which is incorporated herein by reference. For example, cooling can be by supplying a cooling fluid, for example, water (*e.g.*, with glycerol), or nitrogen (*e.g.*, liquid nitrogen) to the bottom of the conveying trough. Alternatively, a cooling gas, for example, chilled
15 nitrogen can be blown over the biomass materials or under the conveying system.

 Another optional pre-treatment processing method can include adding a material to the biomass or other feedstocks. The additional material can be added by, for example, by showering, sprinkling and or pouring the material onto the biomass as it is conveyed. Materials that can be added include, for example, metals, ceramics and/or
20 ions as described in U.S. Pat. App. Pub. 2010/0105119 A1 (filed October 26, 2009) and U.S. Pat. App. Pub. 2010/0159569 A1 (filed December 16, 2009), the entire disclosures of which are incorporated herein by reference. Optional materials that can be added include acids and bases. Other materials that can be added are oxidants (*e.g.*, peroxides, chlorates), polymers, polymerizable monomers (*e.g.*, containing unsaturated bonds),
25 water, catalysts, enzymes and/or organisms. Materials can be added, for example, in pure form, as a solution in a solvent (*e.g.*, water or an organic solvent) and/or as a solution. In some cases the solvent is volatile and can be made to evaporate *e.g.*, by heating and/or blowing gas as previously described. The added material may form a uniform coating on the biomass or be a homogeneous mixture of different components
30 (*e.g.*, biomass and additional material). The added material can modulate the subsequent irradiation step by increasing the efficiency of the irradiation, damping the irradiation or changing the effect of the irradiation (*e.g.*, from electron beams to X-rays or heat). The method may have no impact on the irradiation but may be useful for further downstream

processing. The added material may help in conveying the material, for example, by lowering dust levels.

Biomass can be delivered to conveyor (*e.g.*, vibratory conveyors that can be used in the vaults herein described) by a belt conveyor, a pneumatic conveyor, a screw conveyor, a hopper, a pipe, manually or by a combination of these. The biomass can, for example, be dropped, poured and/or placed onto the conveyor by any of these methods. In some embodiments the material is delivered to the conveyor using an enclosed material distribution system to help maintain a low oxygen atmosphere and/or control dust and fines. Lofted or air suspended biomass fines and dust are undesirable because these can form an explosion hazard or damage the window foils of an electron gun (if such a device is used for treating the material).

The material can be leveled to form a uniform thickness between about 0.0312 and 5 inches (*e.g.*, between about 0.0625 and 2.000 inches, between about 0.125 and 1 inches, between about 0.125 and 0.5 inches, between about 0.3 and 0.9 inches, between about 0.2 and 0.5 inches between about 0.25 and 1.0 inches, between about 0.25 and 0.5 inches, 0.100 +/- 0.025 inches, 0.150 +/- 0.025 inches, 0.200 +/- 0.025 inches, 0.250 +/- 0.025 inches, 0.300 +/- 0.025 inches, 0.350 +/- 0.025 inches, 0.400 +/- 0.025 inches, 0.450 +/- 0.025 inches, 0.500 +/- 0.025 inches, 0.550 +/- 0.025 inches, 0.600 +/- 0.025 inches, 0.700 +/- 0.025 inches, 0.750 +/- 0.025 inches, 0.800 +/- 0.025 inches, 0.850 +/- 0.025 inches, 0.900 +/- 0.025 inches, 0.900 +/- 0.025 inches).

Generally, it is preferred to convey the material as quickly as possible through the electron beam to maximize throughput. For example the material can be conveyed at rates of at least 1 ft/min, *e.g.*, at least 2 ft/min, at least 3 ft/min, at least 4 ft/min, at least 5 ft/min, at least 10 ft/min, at least 15 ft/min, 20, 25, 30, 35, 40, 45, 50 ft/min. The rate of conveying is related to the beam current, for example, for a ¼ inch thick biomass and 100 mA, the conveyor can move at about 20 ft/min to provide a useful irradiation dosage, at 50 mA the conveyor can move at about 10 ft/min to provide approximately the same irradiation dosage.

After the biomass material has been conveyed through the radiation zone, optional post-treatment processing can be done. The optional post-treatment processing can, for example, be a process described with respect to the pre-irradiation processing. For example, the biomass can be screened, heated, cooled, and/or combined with additives. Uniquely to post-irradiation, quenching of the radicals can occur, for example, quenching of radicals by the addition of fluids or gases (*e.g.*, oxygen, nitrous oxide,

ammonia, liquids), using pressure, heat, and/or the addition of radical scavengers. For example, the biomass can be conveyed out of the enclosed conveyor and exposed to a gas (*e.g.*, oxygen) where it is quenched, forming carboxylated groups. In one embodiment the biomass is exposed during irradiation to the reactive gas or fluid.

- 5 Quenching of biomass that has been irradiated is described in U.S. Pat. No. 8,083,906 published Dec 27, 2011, the entire disclosure of which is incorporate herein by reference.

If desired, one or more mechanical treatments can be used in addition to irradiation to further reduce the recalcitrance of the carbohydrate-containing material. These processes can be applied before, during and or after irradiation.

- 10 In some cases, the mechanical treatment may include an initial preparation of the feedstock as received, *e.g.*, size reduction of materials, such as by comminution, *e.g.*, cutting, grinding, shearing, pulverizing or chopping. For example, in some cases, loose feedstock (*e.g.*, recycled paper, starchy materials, or switchgrass) is prepared by shearing or shredding. Mechanical treatment may reduce the bulk density of the carbohydrate-
15 containing material, increase the surface area of the carbohydrate-containing material and/or decrease one or more dimensions of the carbohydrate-containing material.

- Alternatively, or in addition, the feedstock material can be treated with another treatment, for example chemical treatments, such as with an acid (HCl, H₂SO₄, H₃PO₄), a base (*e.g.*, KOH and NaOH), a chemical oxidant (*e.g.*, peroxides, chlorates, ozone),
20 irradiation, steam explosion, pyrolysis, sonication, oxidation, chemical treatment. The treatments can be in any order and in any sequence and combinations. For example, the feedstock material can first be physically treated by one or more treatment methods, *e.g.*, chemical treatment including and in combination with acid hydrolysis (*e.g.*, utilizing HCl, H₂SO₄, H₃PO₄), radiation, sonication, oxidation, pyrolysis or steam explosion, and
25 then mechanically treated. This sequence can be advantageous since materials treated by one or more of the other treatments, *e.g.*, irradiation or pyrolysis, tend to be more brittle and, therefore, it may be easier to further change the structure of the material by mechanical treatment. As another example, a feedstock material can be conveyed through ionizing radiation using a conveyor as described herein and then mechanically
30 treated. Chemical treatment can remove some or all of the lignin (for example chemical pulping) and can partially or completely hydrolyze the material. The methods also can be used with pre-hydrolyzed material. The methods also can be used with material that has not been pre hydrolyzed The methods can be used with mixtures of hydrolyzed and non-hydrolyzed materials, for example with about 50% or more non-hydrolyzed

material, with about 60% or more non- hydrolyzed material, with about 70% or more non-hydrolyzed material, with about 80% or more non-hydrolyzed material or even with 90% or more non-hydrolyzed material.

In addition to size reduction, which can be performed initially and/or later in processing, mechanical treatment can also be advantageous for “opening up,” “stressing,” breaking or shattering the carbohydrate-containing materials, making the cellulose of the materials more susceptible to chain scission and/or disruption of crystalline structure during the physical treatment.

Methods of mechanically treating the carbohydrate-containing material include, for example, milling or grinding. Milling may be performed using, for example, a hammer mill, ball mill, colloid mill, conical or cone mill, disk mill, edge mill, Wiley mill, grist mill or other mill. Grinding may be performed using, for example, a cutting/impact type grinder. Some exemplary grinders include stone grinders, pin grinders, coffee grinders, and burr grinders. Grinding or milling may be provided, for example, by a reciprocating pin or other element, as is the case in a pin mill. Other mechanical treatment methods include mechanical ripping or tearing, other methods that apply pressure to the fibers, and air attrition milling. Suitable mechanical treatments further include any other technique that continues the disruption of the internal structure of the material that was initiated by the previous processing steps.

Mechanical feed preparation systems can be configured to produce streams with specific characteristics such as, for example, specific maximum sizes, specific length-to-width, or specific surface areas ratios. Physical preparation can increase the rate of reactions, improve the movement of material on a conveyor, improve the irradiation profile of the material, improve the radiation uniformity of the material, or reduce the processing time required by opening up the materials and making them more accessible to processes and/or reagents, such as reagents in a solution.

The bulk density of feedstocks can be controlled (*e.g.*, increased). In some situations, it can be desirable to prepare a low bulk density material, *e.g.*, by densifying the material (*e.g.*, densification can make it easier and less costly to transport to another site) and then reverting the material to a lower bulk density state (*e.g.*, after transport). The material can be densified, for example from less than about 0.2 g/cc to more than about 0.9 g/cc (*e.g.*, less than about 0.3 to more than about 0.5 g/cc, less than about 0.3 to more than about 0.9 g/cc, less than about 0.5 to more than about 0.9 g/cc, less than about 0.3 to more than about 0.8 g/cc, less than about 0.2 to more than about 0.5 g/cc). For

example, the material can be densified by the methods and equipment disclosed in U.S. Pat. No. 7,932,065 to Medoff and International Publication No. WO 2008/073186 (which was filed October 26, 2007, was published in English, and which designated the United States), the full disclosures of which are incorporated herein by reference.

- 5 Densified materials can be processed by any of the methods described herein, or any material processed by any of the methods described herein can be subsequently densified.

In some embodiments, the material to be processed is in the form of a fibrous material that includes fibers provided by shearing a fiber source. For example, the
10 shearing can be performed with a rotary knife cutter.

For example, a fiber source, *e.g.*, that is recalcitrant or that has had its recalcitrance level reduced, can be sheared, *e.g.*, in a rotary knife cutter, to provide a first fibrous material. The first fibrous material is passed through a first screen, *e.g.*, having an average opening size of 1.59 mm or less (1/16 inch, 0.0625 inch), provide a second
15 fibrous material. If desired, the fiber source can be cut prior to the shearing, *e.g.*, with a shredder. For example, when a paper is used as the fiber source, the paper can be first cut into strips that are, *e.g.*, 1/4- to 1/2-inch wide, using a shredder, *e.g.*, a counter-rotating screw shredder, such as those manufactured by Munson (Utica, N.Y.). As an alternative to shredding, the paper can be reduced in size by cutting to a desired size
20 using a guillotine cutter. For example, the guillotine cutter can be used to cut the paper into sheets that are, *e.g.*, 10 inches wide by 12 inches long.

In some embodiments, the shearing of the fiber source and the passing of the resulting first fibrous material through a first screen are performed concurrently. The shearing and the passing can also be performed in a batch-type process.

- 25 For example, a rotary knife cutter can be used to concurrently shear the fiber source and screen the first fibrous material. A rotary knife cutter includes a hopper that can be loaded with a shredded fiber source prepared by shredding a fiber source.

In some implementations, the feedstock is physically treated prior to saccharification and/or fermentation. Physical treatment processes can include one or
30 more of any of those described herein, such as mechanical treatment, chemical treatment, irradiation, sonication, oxidation, pyrolysis or steam explosion. Treatment methods can be used in combinations of two, three, four, or even all of these technologies (in any order). When more than one treatment method is used, the methods can be applied at the same time or at different times. Other processes that change a molecular structure of a

biomass feedstock may also be used, alone or in combination with the processes disclosed herein.

Mechanical treatments that may be used, and the characteristics of the mechanically treated carbohydrate-containing materials, are described in further detail in U.S. Pat. App. Pub. 2012/0100577 A1, filed October 18, 2011, the full disclosure of which is hereby incorporated herein by reference.

SONICATION, PYROLYSIS, OXIDATION, STEAM EXPLOSION

If desired, one or more sonication, pyrolysis, oxidative, or steam explosion processes can be used instead of or in addition to irradiation to reduce or further reduce the recalcitrance of the carbohydrate-containing material. For example, these processes can be applied before, during and or after irradiation. These processes are described in detail in U.S. Pat. No. 7,932,065 to Medoff, the full disclosure of which is incorporated herein by reference.

INTERMEDIATES AND PRODUCTS

Using the processes described herein, the biomass material can be converted to one or more products, such as energy (*e.g.*, in addition to co-generation as described herein), fuels, foods and materials. For example, intermediates and products such as organic acids, salts of organic acids, anhydrides, esters of organic acids and fuels, *e.g.*, fuels for internal combustion engines or feedstocks for fuel cells can be produced. Systems and processes are described herein that can use as feedstock cellulosic and/or lignocellulosic materials that are readily available, but often can be difficult to process, *e.g.*, municipal waste streams and waste paper streams, such as streams that include newspaper, Kraft paper, corrugated paper or mixtures of these.

Specific examples of products include, but are not limited to, hydrogen, sugars (*e.g.*, glucose, xylose, arabinose, mannose, galactose, fructose, disaccharides, oligosaccharides and polysaccharides), alcohols (*e.g.*, monohydric alcohols or dihydric alcohols, such as ethanol, n-propanol, isobutanol, sec-butanol, tert-butanol or n-butanol), hydrated or hydrous alcohols (*e.g.*, containing greater than 10%, 20%, 30% or even greater than 40% water), biodiesel, organic acids, hydrocarbons (*e.g.*, methane, ethane, propane, isobutene, pentane, n-hexane, biodiesel, bio-gasoline and mixtures thereof), co-

products (*e.g.*, proteins, such as cellulolytic proteins (enzymes) or single cell proteins), and mixtures of any of these in any combination or relative concentration, and optionally in combination with any additives (*e.g.*, fuel additives). Other examples include

5 carboxylic acids, salts of a carboxylic acid, a mixture of carboxylic acids and salts of carboxylic acids and esters of carboxylic acids (*e.g.*, methyl, ethyl and n-propyl esters), ketones (*e.g.*, acetone), aldehydes (*e.g.*, acetaldehyde), alpha and beta unsaturated acids (*e.g.*, acrylic acid) and olefins (*e.g.*, ethylene). Other alcohols and alcohol derivatives include propanol, propylene glycol, 1,4-butanediol, 1,3-propanediol, sugar alcohols (*e.g.*, erythritol, glycol, glycerol, sorbitol, threitol, arabitol, ribitol, mannitol, dulcitol, fucitol,

10 iditol, isomalt, maltitol, lactitol, xylitol and other polyols), and methyl or ethyl esters of any of these alcohols. Other products include methyl acrylate, methylmethacrylate, D-lactic acid, L-lactic acid, pyruvic acid, poly lactic acid, citric acid, formic acid, acetic acid, propionic acid, butyric acid, succinic acid, valeric acid, caproic acid, 3-hydroxypropionic acid, palmitic acid, stearic acid, oxalic acid, malonic acid, glutaric

15 acid, oleic acid, linoleic acid, glycolic acid, gamma-hydroxybutyric acid, and mixtures thereof, salts of any of these acids, mixtures of any of the acids and their respective salts.

Any combination of the above products with each other, and/or of the above products with other products, which other products may be made by the processes described herein or otherwise, may be packaged together and sold as products. The

20 products may be combined, *e.g.*, mixed, blended or co-dissolved, or may simply be packaged or sold together.

Any of the products or combinations of products described herein may be sanitized or sterilized prior to selling the products, *e.g.*, after purification or isolation or even after packaging, to neutralize one or more potentially undesirable contaminants that

25 could be present in the product(s). Such sanitation can be done with electron bombardment, for example, by at a dosage of less than about 20 Mrad, *e.g.*, from about 0.1 to 15 Mrad, from about 0.5 to 7 Mrad, or from about 1 to 3 Mrad.

The processes described herein can produce various by-product streams useful for generating steam and electricity to be used in other parts of the plant (co-generation)

30 or sold on the open market (*e.g.*, as previously described herein). For example, steam generated from burning by-product streams can be used in a distillation process. As another example, electricity generated from burning by-product streams can be used to power electron beam generators used in pretreatment.

The by-products used to generate steam and electricity are derived from a number of sources throughout the process. For example, anaerobic digestion of wastewater can produce a biogas high in methane and a small amount of waste biomass (sludge). As another example, post-saccharification and/or post-distillate solids (*e.g.*, unconverted lignin, cellulose, and hemicellulose remaining from the pretreatment and primary processes) can be used, *e.g.*, burned, as a fuel.

Other intermediates and products, including food and pharmaceutical products, are described in U.S. Pat. App. Pub. 2010/0124583 A1, published May 20, 2010, to Medoff, the full disclosure of which is hereby incorporated by reference herein.

LIGNIN DERIVED PRODUCTS

The spent biomass (*e.g.*, spent lignocellulosic material) from lignocellulosic processing by the methods described are expected to have a high lignin content and in addition to being useful for producing energy through combustion in a Co-Generation plant, may have uses as other valuable products. For example, the lignin can be used as captured as a plastic, or it can be synthetically upgraded to other plastics. In some instances, it can also be converted to lignosulfonates, which can be utilized as binders, dispersants, emulsifiers or sequestrants.

When used as a binder, the lignin or a lignosulfonate can, *e.g.*, be utilized in coal briquettes, in ceramics, for binding carbon black, for binding fertilizers and herbicides, as a dust suppressant, in the making of plywood and particle board, for binding animal feeds, as a binder for fiberglass, as a binder in linoleum paste and as a soil stabilizer.

When used as a dispersant, the lignin or lignosulfonates can be used, *e.g.*, in concrete mixes, clay and ceramics, dyes and pigments, leather tanning and in gypsum board.

When used as an emulsifier, the lignin or lignosulfonates can be used, *e.g.*, in asphalt, pigments and dyes, pesticides and wax emulsions.

When used as a sequestrant, the lignin or lignosulfonates can be used, *e.g.*, in micro-nutrient systems, cleaning compounds and water treatment systems, *e.g.*, for boiler and cooling systems.

For energy production lignin generally has a higher energy content than holocellulose (cellulose and hemicellulose) since it contains more carbon than homocellulose. For example, dry lignin can have an energy content of between about

11,000 and 12,500 BTU per pound, compared to 7,000 and 8,000 BTU per pound of holocellulose. As such, lignin can be densified and converted into briquettes and pellets for burning. For example, the lignin can be converted into pellets by any method described herein. For a slower burning pellet or briquette, the lignin can be crosslinked, such as applying a radiation dose of between about 0.5 Mrad and 5 Mrad. Crosslinking can make a slower burning form factor. The form factor, such as a pellet or briquette, can be converted to a “synthetic coal” or charcoal by pyrolyzing in the absence of air, *e.g.*, at between 400 and 950 DEG C. Prior to pyrolyzing, it can be desirable to crosslink the lignin to maintain structural integrity.

10

SACCHARIFICATION

As previously described, in order to convert the feedstock to a form that can be readily processed the glucan- or xylan-containing cellulose in the feedstock can be hydrolyzed to low molecular weight carbohydrates, such as sugars, by a saccharifying agent, *e.g.*, an enzyme or acid, a process referred to as saccharification. The low molecular weight carbohydrates can then be used, for example, in an existing manufacturing plant, such as a single cell protein plant, an enzyme manufacturing plant, or a fuel plant, *e.g.*, an ethanol manufacturing facility.

As previously disclosed, the feedstock can be hydrolyzed using an enzyme, *e.g.*, by combining the materials and the enzyme in a solvent, *e.g.*, in an aqueous solution.

Alternatively, the enzymes can be supplied by organisms that break down biomass, such as the cellulose and/or the lignin portions of the biomass, contain or manufacture various cellulolytic enzymes (cellulases), ligninases or various small molecule biomass-degrading metabolites. These enzymes may be a complex of enzymes that act synergistically to degrade crystalline cellulose or the lignin portions of biomass. Examples of cellulolytic enzymes include: endoglucanases, cellobiohydrolases, and cellobiases (beta-glucosidases).

During saccharification a cellulosic substrate can be initially hydrolyzed by endoglucanases at random locations producing oligomeric intermediates. These intermediates are then substrates for exo-splitting glucanases such as cellobiohydrolase to produce cellobiose from the ends of the cellulose polymer. Cellobiose is a water-soluble 1,4-linked dimer of glucose. Finally, cellobiase cleaves cellobiose to yield

glucose. The efficiency (*e.g.*, time to hydrolyze and/or completeness of hydrolysis) of this process depends on the recalcitrance of the cellulosic material.

Therefore, the treated biomass materials can be saccharified, by combining the material and a cellulase enzyme in a fluid medium, *e.g.*, an aqueous solution. In some cases, the material is boiled, steeped, or cooked in hot water prior to saccharification, as described in U.S. Pat. App. Pub. 2012/0100577 A1 by Medoff and Masterman, published on April 26, 2012, the entire contents of which are incorporated herein.

The saccharification process can be partially or completely performed in a tank (*e.g.*, a tank having a volume of at least 4000, 40,000, or 500,000 L) in a manufacturing plant, and/or can be partially or completely performed in transit, *e.g.*, in a rail car, tanker truck, or in a supertanker or the hold of a ship. The time required for complete saccharification will depend on the process conditions and the carbohydrate-containing material and enzyme used. If saccharification is performed in a manufacturing plant under controlled conditions, the cellulose may be substantially entirely converted to sugar, *e.g.*, glucose in about 12-96 hours. If saccharification is performed partially or completely in transit, saccharification may take longer.

It is generally preferred that the tank contents be mixed during saccharification, *e.g.*, using jet mixing as described in International App. No. PCT/US2010/035331, filed May 18, 2010, which was published in English as WO 2010/135380 and designated the United States, the full disclosure of which is incorporated by reference herein.

The addition of surfactants can enhance the rate of saccharification. Examples of surfactants include non-ionic surfactants, such as a TWEEN® 20 or TWEEN® 80 polyethylene glycol surfactants, ionic surfactants, or amphoteric surfactants.

It is generally preferred that the concentration of the sugar solution resulting from saccharification be relatively high, *e.g.*, greater than 40%, or greater than 50, 60, 70, 80, 90 or even greater than 95% by weight. Water may be removed, *e.g.*, by evaporation, to increase the concentration of the sugar solution. This reduces the volume to be shipped, and also inhibits microbial growth in the solution.

Alternatively, sugar solutions of lower concentrations may be used, in which case it may be desirable to add an antimicrobial additive, *e.g.*, a broad spectrum antibiotic, in a low concentration, *e.g.*, 50 to 150 ppm. Other suitable antibiotics include amphotericin B, ampicillin, chloramphenicol, ciprofloxacin, gentamicin, hygromycin B, kanamycin, neomycin, penicillin, puromycin, streptomycin. Antibiotics will inhibit growth of microorganisms during transport and storage, and can be used at appropriate

concentrations, *e.g.*, between 15 and 1000 ppm by weight, *e.g.*, between 25 and 500 ppm, or between 50 and 150 ppm. If desired, an antibiotic can be included even if the sugar concentration is relatively high. Alternatively, other additives with anti-microbial or preservative properties may be used. Preferably the antimicrobial additive(s) are food-grade.

A relatively high concentration solution can be obtained by limiting the amount of water added to the carbohydrate-containing material with the enzyme. The concentration can be controlled, *e.g.*, by controlling how much saccharification takes place. For example, concentration can be increased by adding more carbohydrate-containing material to the solution. In order to keep the sugar that is being produced in solution, a surfactant can be added, *e.g.*, one of those discussed above. Solubility can also be increased by increasing the temperature of the solution. For example, the solution can be maintained at a temperature of 40-50 DEG C, 60-80 DEG C, or even higher.

SACCHARIFYING AGENTS

Suitable cellulolytic enzymes include cellulases from species in the genera *Bacillus*, *Coprinus*, *Myceliophthora*, *Cephalosporium*, *Scytalidium*, *Penicillium*, *Aspergillus*, *Pseudomonas*, *Humicola*, *Fusarium*, *Thielavia*, *Acremonium*, *Chrysosporium* and *Trichoderma*, especially those produced by a strain selected from the species *Aspergillus* (see, *e.g.*, EP Pub. No. 0 458 162), *Humicola insolens* (reclassified as *Scytalidium thermophilum*, see, *e.g.*, U.S. Pat. No. 4,435,307), *Coprinus cinereus*, *Fusarium oxysporum*, *Myceliophthora thermophila*, *Meripilus giganteus*, *Thielavia terrestris*, *Acremonium* sp. (including, but not limited to, *A. persicinum*, *A. acremonium*, *A. brachyphenium*, *A. dichromosporum*, *A. obclavatum*, *A. pinkertoniae*, *A. roseogriseum*, *A. incoloratum*, and *A. furatum*). Preferred strains include *Humicola insolens* DSM 1800, *Fusarium oxysporum* DSM 2672, *Myceliophthora thermophila* CBS 117.65, *Cephalosporium* sp. RYM-202, *Acremonium* sp. CBS 478.94, *Acremonium* sp. CBS 265.95, *Acremonium persicinum* CBS 169.65, *Acremonium acremonium* AHU 9519, *Cephalosporium* sp. CBS 535.71, *Acremonium brachyphenium* CBS 866.73, *Acremonium dichromosporum* CBS 683.73, *Acremonium obclavatum* CBS 311.74, *Acremonium pinkertoniae* CBS 157.70, *Acremonium roseogriseum* CBS 134.56, *Acremonium incoloratum* CBS 146.62, and *Acremonium furatum* CBS 299.70H.

Cellulolytic enzymes may also be obtained from *Chrysosporium*, preferably a strain of *Chrysosporium lucknowense*. Additional strains that can be used include, but are not limited to, *Trichoderma* (particularly *T. viride*, *T. reesei*, and *T. koningii*), alkalophilic *Bacillus* (see, for example, U.S. Pat. No. 3,844,890 and EP Pub. No. 0 458 162), and
5 *Streptomyces* (see, *e.g.*, EP Pub. No. 0 458 162).

In addition to or in combination to enzymes, acids, bases and other chemicals (*e.g.*, oxidants) can be utilized to saccharify lignocellulosic and cellulosic materials. These can be used in any combination or sequence (*e.g.*, before, after and/or during addition of an enzyme). For example strong mineral acids can be utilized (*e.g.* HCl,
10 H₂SO₄, H₃PO₄) and strong bases (*e.g.*, NaOH, KOH).

SUGARS

In the processes described herein, for example after saccharification, sugars (*e.g.*,
15 glucose and xylose) can be isolated and/or purified. For example sugars can be isolated and/or purified by precipitation, crystallization, chromatography (*e.g.*, simulated moving bed chromatography, high pressure chromatography), electrodialysis, centrifugation, extraction, any other isolation method known in the art, and combinations thereof.

HYDROGENATION AND OTHER CHEMICAL TRANSFORMATIONS

The processes described herein can include hydrogenation. For example glucose and xylose can be hydrogenated to sorbitol and xylitol respectively. Hydrogenation can be accomplished by use of a catalyst (*e.g.*, Pt/gamma-Al₂O₃, Ru/C, Raney Nickel, or
25 other catalysts known in the art) in combination with H₂ under high pressure (*e.g.*, 10 to 12000 psi). Other types of chemical transformation of the products from the processes described herein can be used, for example production of organic sugar derived products (*e.g.*, furfural and furfural-derived products). Chemical transformations of sugar derived products are described in USSN 13/934,704 filed July 3, 2013, the entire disclosure of
30 which is incorporated herein by reference in its entirety.

FERMENTATION

Yeast and Zymomonas bacteria, for example, can be used for fermentation or conversion of sugar(s) to alcohol(s). Other microorganisms are discussed below. The optimum pH for fermentations is about pH 4 to 7. For example, the optimum pH for yeast is from about pH 4 to 5, while the optimum pH for Zymomonas is from about pH 5 to 6. Typical fermentation times are about 24 to 168 hours (*e.g.*, 24 to 96 hrs) with temperatures in the range of 20°C to 40°C (*e.g.*, 26°C to 40°C), however thermophilic microorganisms prefer higher temperatures.

In some embodiments, *e.g.*, when anaerobic organisms are used, at least a portion of the fermentation is conducted in the absence of oxygen, *e.g.*, under a blanket of an inert gas such as N₂, Ar, He, CO₂ or mixtures thereof. Additionally, the mixture may have a constant purge of an inert gas flowing through the tank during part of or all of the fermentation. In some cases, anaerobic condition, can be achieved or maintained by carbon dioxide production during the fermentation and no additional inert gas is needed.

In some embodiments, all or a portion of the fermentation process can be interrupted before the low molecular weight sugar is completely converted to a product (*e.g.*, ethanol). The intermediate fermentation products include sugar and carbohydrates in high concentrations. The sugars and carbohydrates can be isolated via any means known in the art. These intermediate fermentation products can be used in preparation of food for human or animal consumption. Additionally or alternatively, the intermediate fermentation products can be ground to a fine particle size in a stainless-steel laboratory mill to produce a flour-like substance. Jet mixing may be used during fermentation, and in some cases saccharification and fermentation are performed in the same tank.

Nutrients for the microorganisms may be added during saccharification and/or fermentation, for example the food-based nutrient packages described in U.S. Pat. App. Pub. 2012/0052536, filed July 15, 2011, the complete disclosure of which is incorporated herein by reference.

“Fermentation” includes the methods and products that are disclosed in application Nos. PCT/US2012/71093 published June 27, 2013, PCT/US2012/71907 published June 27, 2012, and PCT/US2012/71083 published June 27, 2012 the contents of which are incorporated by reference herein in their entirety.

Mobile fermenters can be utilized, as described in International App. No. PCT/US2007/074028 (which was filed July 20, 2007, was published in English as WO 2008/011598 and designated the United States) and has a US issued Patent No. 8,318,453, the contents of which are incorporated herein in its entirety. Similarly, the
 5 saccharification equipment can be mobile. Further, saccharification and/or fermentation may be performed in part or entirely during transit.

FERMENTATION AGENTS

10 The microorganism(s) used in fermentation can be naturally-occurring microorganisms and/or engineered microorganisms. For example, the microorganism can be a bacterium (including, but not limited to, *e.g.*, a cellulolytic bacterium), a fungus, (including, but not limited to, *e.g.*, a yeast), a plant, a protist, *e.g.*, a protozoa or a fungus-like protest (including, but not limited to, *e.g.*, a slime mold), or an alga. When the
 15 organisms are compatible, mixtures of organisms can be utilized.

Suitable fermenting microorganisms have the ability to convert carbohydrates, such as glucose, fructose, xylose, arabinose, mannose, galactose, oligosaccharides or polysaccharides into fermentation products. Fermenting microorganisms include strains of the genus *Saccharomyces spp.* (including, but not limited to, *S. cerevisiae* (baker's yeast), *S. distaticus*, *S. uvarum*), the genus *Kluyveromyces*, (including, but not limited to, *K. marxianus*, *K. fragilis*), the genus *Candida* (including, but not limited to, *C. pseudotropicalis*, and *C. brassicae*), *Pichia stipitis* (a relative of *Candida shehatae*), the genus *Clavispora* (including, but not limited to, *C. lusitaniae* and *C. opuntiae*), the genus *Pachysolen* (including, but not limited to, *P. tannophilus*), the genus *Bretannomyces*
 20 (including, but not limited to, *e.g.*, *B. clausenii* (Philippidis, G. P., 1996, Cellulose bioconversion technology, in Handbook on Bioethanol: Production and Utilization, Wyman, C.E., ed., Taylor & Francis, Washington, DC, 179-212)). Other suitable microorganisms include, for example, *Zymomonas mobilis*, *Clostridium spp.* (including, but not limited to, *C. thermocellum* (Philippidis, 1996, supra), *C. saccharobutylaceticum*, *C. tyrobutyricum*, *C. saccharobutylicum*, *C. Puniceum*, *C. beijerinckii*, and *C. acetobutylicum*), *Moniliella spp.* (including but not limited to *M. pollinis*, *M. tomentosa*, *M. madida*, *M. nigrescens*, *M. oedocephali*, *M. megachiliensis*), *Yarrowia lipolytica*, *Aureobasidium sp.*, *Trichosporonoides sp.*, *Trigonopsis variabilis*, *Trichosporon sp.*, *Moniliellaacetoabutans sp.*, *Typhula variabilis*, *Candida magnoliae*,

Ustilaginomycetes sp., *Pseudozyma tsukubaensis*, yeast species of genera *Zygosaccharomyces*, *Debaryomyces*, *Hansenula* and *Pichia*, and fungi of the dematioid genus *Torula* (e.g., *T.corallina*).

Additional microorganisms include the *Lactobacillus* group. Examples include
 5 *Lactobacillus casei*, *Lactobacillus rhamnosus*, *Lactobacillus delbrueckii*, *Lactobacillus plantarum*, *Lactobacillus coryniformis*, e.g., *Lactobacillus coryniformis* subspecies *torquens*, *Lactobacillus pentosus*, *Lactobacillus brevis*. Other microorganisms include *Pediococcus penosaceus*, *Rhizopus oryzae*.

Several organisms, such as bacteria, yeasts and fungi, can be utilized to ferment
 10 biomass derived products such as sugars and alcohols to succinic acid and similar products. For example, organisms can be selected from; *Actinobacillus succinogenes*, *Anaerobiospirillum succiniciproducens*, *Mannheimia succiniciproducens*, *Ruminococcus flaverfaciens*, *Ruminococcus albus*, *Fibrobacter succinogenes*, *Bacteroides fragilis*, *Bacteroides ruminicola*, *Bacteroides amylophilus*, *Bacteriodes succinogenes*,
 15 *Mannheimia succiniciproducens*, *Corynebacterium glutamicum*, *Aspergillus niger*, *Aspergillus fumigatus*, *Byssoschlamys nivea*, *Lentinus degener*, *Paecilomyces varioti*, *Penicillium viniferum*, *Saccharomyces cerevisiae*, *Enterococcus faecali*, *Prevotella ruminicolas*, *Debaryomyces hansenii*, *Candida catenulata* VKM Y-5, *C. mycoderma* VKM Y-240, *C. rugosa* VKM Y-67, *C. paludigena* VKM Y-2443, *C. utilis* VKM Y-74,
 20 *C. utilis* 766, *C. zeylanoides* VKM Y-6, *C. zeylanoides* VKM Y-14, *C. zeylanoides* VKM Y-2324, *C. zeylanoides* VKM Y-1543, *C. zeylanoides* VKM Y-2595, *C. valida* VKM Y-934, *Kluyveromyces wickerhamii* VKM Y-589, *Pichia anomala* VKM Y-118, *P. besseyi* VKM Y-2084, *P. media* VKM Y-1381, *P. guilliermondii* H-P-4, *P. guilliermondii* 916, *P. inositolovora* VKM Y-2494, *Saccharomyces cerevisiae* VKM Y-381, *Torulopsis*
 25 *candida* 127, *T. candida* 420, *Yarrowia lipolytica* 12a, *Y. lipolytica* VKM Y-47, *Y. lipolytica* 69, *Y. lipolytica* VKM Y-57, *Y. lipolytica* 212, *Y. lipolytica* 374/4, *Y. lipolytica* 585, *Y. lipolytica* 695, *Y. lipolytica* 704, and mixtures of these organisms.

Many such microbial strains are publicly available, either commercially or through depositories such as the ATCC (American Type Culture Collection, Manassas,
 30 Virginia, USA), the NRRL (Agricultural Research Service Culture Collection, Peoria, Illinois, USA), or the DSMZ (Deutsche Sammlung von Mikroorganismen und Zellkulturen GmbH, Braunschweig, Germany), to name a few.

Commercially available yeasts include, for example, RED STAR®/Lesaffre Ethanol Red (available from Red Star/Lesaffre, USA), FALI® (available from

Fleischmann's Yeast, a division of Burns Philip Food Inc., USA), SUPERSTART® (available from Alltech, now Lalemand), GERT STRAND® (available from Gert Strand AB, Sweden) and FERMOL® (available from DSM Specialties).

5

DISTILLATION

As previously described, after fermentation, the resulting fluids can be distilled using, for example, a "beer column" to separate ethanol and other alcohols from the majority of water and residual solids. The vapor exiting the beer column can be, *e.g.*,
10 35% by weight ethanol and can be fed to a rectification column. A mixture of nearly azeotropic (92.5%) ethanol and water from the rectification column can be purified to pure (99.5%) ethanol using vapor-phase molecular sieves. The beer column bottoms can be sent to the first effect of a three-effect evaporator. The rectification column reflux condenser can provide heat for this first effect. After the first effect, solids can be
15 separated using a centrifuge and dried in a rotary dryer. A portion (25%) of the centrifuge effluent can be recycled to fermentation and the rest sent to the second and third evaporator effects. Most of the evaporator condensate can be returned to the process as fairly clean condensate with a small portion split off to waste water treatment to prevent build-up of low-boiling compounds.

20

HYDROCARBON-CONTAINING MATERIALS

In other embodiments utilizing the methods and systems described herein, hydrocarbon-containing materials, for example, mixed with biomass can be processed.
25 For example, the energy generated in a cogeneration plant can be used to process hydrocarbon containing materials, or hydrocarbon containing materials can be used in producing energy by providing fuel for a boiler. Some of the process described herein can be used to treat any hydrocarbon-containing material herein described. "Hydrocarbon-containing materials," as used herein, is meant to include oil sands, oil
30 shale, tar sands, coal dust, coal slurry, bitumen, various types of coal, and other naturally-occurring and synthetic materials that include both hydrocarbon components and solid matter. The solid matter can include rock, sand, clay, stone, silt, drilling slurry, or other solid organic and/or inorganic matter. The term can also include waste products such as drilling waste and by-products, refining waste and by-products, or other waste

products containing hydrocarbon components, such as asphalt shingling and covering, asphalt pavement, etc.

CONVEYING SYSTEMS

5

Various conveying systems can be used to convey the biomass material, for example, as discussed, to a vault, and under an electron beam in a vault. Exemplary conveyors are belt conveyors, pneumatic conveyors, screw conveyors, carts, trains, trains or carts on rails, elevators, front loaders, backhoes, cranes, various scrapers and shovels, trucks, and throwing devices can be used. For example, vibratory conveyors can be used in various processes described herein. Vibratory conveyors are described in PCT/US2013/64289 filed October 10, 2013 the full disclosure of which is incorporated by reference herein.

Vibratory conveyors are particularly useful for spreading the material and producing a uniform layer on the conveyor trough surface. For example the initial feedstock can form a pile of material that can be at least four feet high (e.g., at least about 3 feet, at least about 2 feet, at least about 1 foot, at least about 6 inches, at least about 5 inches, at least about, 4 inches, at least about 3 inches, at least about 2 inches, at least about 1 inch, at least about ½ inch) and spans less than the width of the conveyor (e.g., less than about 10%, less than about 20%, less than about 30%, less than about 40%, less than about 50%, less than about 60%, less than about 70%, less than about 80%, less than about 90%, less than about 95%, less than about 99%). The vibratory conveyor can spread the material to span the entire width of the conveyor trough and have a uniform thickness, preferably as discussed above. In some cases, an additional spreading method can be useful. For example, a spreader such as a broadcast spreader, a drop spreader (e.g., a CHRISTY SPREADER™) or combinations thereof can be used to drop (e.g., place, pour, spill and/or sprinkle) the feedstock over a wide area. Optionally, the spreader can deliver the biomass as a wide shower or curtain onto the vibratory conveyor. Additionally, a second conveyor, upstream from the first conveyor (e.g., the first conveyor is used in the irradiation of the feedstock), can drop biomass onto the first conveyor, where the second conveyor can have a width transverse to the direction of conveying smaller than the first conveyor. In particular, when the second conveyor is a vibratory conveyor, the feedstock is spread by the action of the second and first conveyor. In some optional embodiments, the second conveyor ends in a bias cross cut

discharge (e.g., a bias cut with a ratio of 4:1) so that the material can be dropped as a wide curtain (e.g., wider than the width of the second conveyor) onto the first conveyor. The initial drop area of the biomass by the spreader (e.g., broadcast spreader, drop spreader, conveyor, or cross cut vibratory conveyor) can span the entire width of the first
5 vibratory conveyor, or it can span part of this width. Once dropped onto the conveyor, the material is spread even more uniformly by the vibrations of the conveyor so that, preferably, the entire width of the conveyor is covered with a uniform layer of biomass. In some embodiments combinations of spreaders can be used. Some methods of spreading a feed stock are described in U.S. Patent No. 7,153,533, filed July 23, 2002
10 and published December 26, 2006, the entire disclosure of which is incorporated herein by reference.

Generally, it is preferred to convey the material as quickly as possible through an electron beam to maximize throughput. For example, the material can be conveyed at rates of at least 1 ft/min, e.g., at least 2 ft/min, at least 3 ft/min, at least 4 ft/min, at least
15 ft/min, at least 10 ft/min, at least 15 ft/min, at least 20 ft/min, at least 25 ft/min, at least 30 ft/min, at least 40 ft/min, at least 50 ft/min, at least 60 ft/min, at least 70 ft/min, at least 80 ft/min, at least 90 ft/min. The rate of conveying is related to the beam current and targeted irradiation dose, for example, for a ¼ inch thick biomass spread over a 5.5 foot wide conveyor and 100 mA, the conveyor can move at about 20 ft/min to provide a
20 useful irradiation dosage (e.g. about 10 Mrad for a single pass), at 50 mA the conveyor can move at about 10 ft/min to provide approximately the same irradiation dosage.

The rate at which material can be conveyed depends on the shape and mass of the material being conveyed, and the desired treatment. Flowing materials e.g., particulate materials, are particularly amenable to conveying with vibratory conveyors. Conveying
25 speeds can, for example be, at least 100 lb/hr (e.g., at least 500 lb/hr, at least 1000 lb/hr, at least 2000 lb/hr, at least 3000 lb/hr, at least 4000 lb/hr, at least 5000 lb/hr, at least 10,000 lb/hr, at least 15,000 lb/hr, or even at least 25,000 lb/hr). Some typical conveying speeds can be between about 1000 and 10,000 lb/hr, (e.g., between about 1000 lb/hr and 8000 lb/hr, between about 2000 and 7000 lb/hr, between about 2000 and 6000 lb/hr,
30 between about 2000 and 5000 lb/hr, between about 2000 and 4500 lb/hr, between about 1500 and 5000 lb/hr, between about 3000 and 7000 lb/hr, between about 3000 and 6000 lb/hr, between about 4000 and 6000 lb/hr and between about 4000 and 5000 lb/hr). Typical conveying speeds depend on the density of the material. For example, for a biomass with a density of about 35 lb/ft³, and a conveying speed of about 5000 lb/hr, the

material is conveyed at a rate of about 143 ft³/hr, if the material is ¼" thick and is in a trough 5.5 ft wide, the material is conveyed at a rate of about 1250 ft/hr (about 21 ft/min). Rates of conveying the material can therefore vary greatly. Preferably, for example, a ¼" thick layer of biomass, is conveyed at speeds of between about 5 and 100 ft/min (e.g. between about 5 and 100 ft/min, between about 6 and 100 ft/min, between about 7 and 100 ft/min, between about 8 and 100 ft/min, between about 9 and 100 ft/min, between about 10 and 100 ft/min, between about 11 and 100 ft/min, between about 12 and 100 ft/min, between about 13 and 100 ft/min, between about 14 and 100 ft/min, between about 15 and 100 ft/min, between about 20 and 100 ft/min, between about 30 and 100 ft/min, between about 40 and 100 ft/min, between about 2 and 60 ft/min, between about 3 and 60 ft/min, between about 5 and 60 ft/min, between about 6 and 60 ft/min, between about 7 and 60 ft/min, between about 8 and 60 ft/min, between about 9 and 60 ft/min, between about 10 and 60 ft/min, between about 15 and 60 ft/min, between about 20 and 60 ft/min, between about 30 and 60 ft/min, between about 40 and 60 ft/min, between about 2 and 50 ft/min, between about 3 and 50 ft/min, between about 5 and 50 ft/min, between about 6 and 50 ft/min, between about 7 and 50 ft/min, between about 8 and 50 ft/min, between about 9 and 50 ft/min, between about 10 and 50 ft/min, between about 15 and 50 ft/min, between about 20 and 50 ft/min, between about 30 and 50 ft/min, between about 40 and 50 ft/min). It is preferable that the material be conveyed at a constant rate, for example, to help maintain a constant irradiation of the material as it passes under the electron beam (e.g., shower, field).

The vibratory conveyors described can include screens used for sieving and sorting materials. Port openings on the side or bottom of the troughs can be used for sorting, selecting or removing specific materials, for example, by size or shape. Some conveyors have counterbalances to reduce the dynamic forces on the support structure. Some vibratory conveyors are configured as spiral elevators, are designed to curve around surfaces and/or are designed to drop material from one conveyor to another (e.g., in a step, cascade or as a series of steps or a stair). Along with conveying materials conveyors can be used, by themselves or coupled with other equipment or systems, for screening, separating, sorting, classifying, distributing, sizing, inspection, picking, metal removing, freezing, blending, mixing, orienting, heating, cooking, drying, dewatering, cleaning, washing, leaching, quenching, coating, de-dusting and/or feeding. The conveyors can also include covers (e.g., dust-tight covers), side discharge gates, bottom discharge gates, special liners (e.g., anti-stick, stainless steel, rubber, custom steal, and or

grooved), divided troughs, quench pools, screens, perforated plates, detectors (e.g., metal detectors), high temperature designs, food grade designs, heaters, dryers and or coolers. In addition, the trough can be of various shapes, for example, flat bottomed, vee shaped bottom, flanged at the top, curved bottom, flat with ridges in any direction, tubular, half
5 pipe, covered or any combinations of these. In particular, the conveyors can be coupled with an irradiation systems and/or equipment.

The conveyors (e.g., vibratory conveyor) can be made of corrosion resistant materials. The conveyors can utilize structural materials that include stainless steel (e.g., 304, 316 stainless steel, HASTELLOY® ALLOYS and INCONEL® Alloys). For
10 example, HASTELLOY® Corrosion-Resistant alloys from Hynes (Kokomo, Indiana, USA) such as HASTELLOY® B-3® ALLOY, HASTELLOY® HYBRID-BC1® ALLOY, HASTELLOY® C-4 ALLOY, HASTELLOY® C-22® ALLOY, HASTELLOY® C-22HS® ALLOY, HASTELLOY® C-276 ALLOY, HASTELLOY® C-2000® ALLOY, HASTELLOY® G-30® ALLOY, HASTELLOY® G-35® ALLOY,
15 HASTELLOY® N ALLOY and HASTELLOY® ULTIMET® alloy.

The vibratory conveyors can include non-stick release coatings, for example, TUFFLON™ (Dupont, Delaware, USA). The vibratory conveyors can also include corrosion resistant coatings. For example, coatings that can be supplied from Metal Coatings Corp (Houston, Texas, USA) and others such as Fluoropolymer, Xylan®,
20 Molybdenum Disulfide, Epoxy Phenolic, Phosphate- ferrous metal coating, Polyurethane- high gloss topcoat for epoxy, inorganic zinc, Poly Tetrafluoro ethylene, PPS/Ryton®, fluorinated ethylene propylene, PVDF/DYKOR®, ECTFE/HALAR® and Ceramic Epoxy Coating. The coatings can improve resistance to process gases (e.g., ozone), chemical corrosion, pitting corrosion, galling corrosion and oxidation.

25 Optionally, in addition to the conveying systems described herein, one or more other conveying systems can be enclosed. When using an enclosure, the enclosed conveyor can also be purged with an inert gas so as to maintain an atmosphere at a reduced oxygen level. Keeping oxygen levels low avoids the formation of ozone which in some instances is undesirable due to its reactive and toxic nature. For example, the
30 oxygen can be less than about 20% (e.g., less than about 10%, less than about 1%, less than about 0.1%, less than about 0.01%, or even less than about 0.001% oxygen). Purging can be done with an inert gas including, but not limited to, nitrogen, argon, helium or carbon dioxide. This can be supplied, for example, from a boil off of a liquid source (e.g., liquid nitrogen or helium), generated or separated from air *in situ*, or

supplied from tanks. The inert gas can be recirculated and any residual oxygen can be removed using a catalyst, such as a copper catalyst bed. Alternatively, combinations of purging, recirculating and oxygen removal can be done to keep the oxygen levels low.

The enclosed conveyor can also be purged with a reactive gas that can react with the biomass. This can be done before, during or after the irradiation process. The reactive gas can be, but is not limited to, nitrous oxide, ammonia, oxygen, ozone, hydrocarbons, aromatic compounds, amides, peroxides, azides, halides, oxyhalides, phosphides, phosphines, arsines, sulfides, thiols, boranes and/or hydrides. The reactive gas can be activated in the enclosure, *e.g.*, by irradiation (*e.g.*, electron beam, UV irradiation, microwave irradiation, heating, IR radiation), so that it reacts with the biomass. The biomass itself can be activated, for example by irradiation. Preferably the biomass is activated by the electron beam, to produce radicals which then react with the activated or unactivated reactive gas, *e.g.*, by radical coupling or quenching.

Purging gases supplied to an enclosed conveyor can also be cooled, for example below about 25°C, below about 0°C, below about -40°C, below about -80°C, below about -120°C. For example, the gas can be boiled off from a compressed gas such as liquid nitrogen or sublimed from solid carbon dioxide. As an alternative example, the gas can be cooled by a chiller or part of or the entire conveyor can be cooled.

20

OTHER EMBODIMENTS

Any material, processes or processed materials discussed herein can be used to make products and/or intermediates such as composites, fillers, binders, plastic additives, adsorbents and controlled release agents. The methods can include densification, for example, by applying pressure and heat to the materials. For example composites can be made by combining fibrous materials with a resin or polymer. For example radiation cross-linkable resin, *e.g.*, a thermoplastic resin can be combined with a fibrous material to provide a fibrous material/cross-linkable resin combination. Such materials can be, for example, useful as building materials, protective sheets, containers and other structural materials (*e.g.*, molded and/or extruded products). Absorbents can be, for example, in the form of pellets, chips, fibers and/or sheets. Adsorbents can be used, for example, as pet bedding, packaging material or in pollution control systems. Controlled release matrices can also be the form of, for example, pellets, chips, fibers and or sheets. The controlled release matrices can, for example, be used to release drugs, biocides, fragrances. For

example, composites, absorbents and control release agents and their uses are described in International Serial No. PCT/US2006/010648, filed March 23, 2006, and US Patent No. 8,074,910 filed November 22, 2011, the entire disclosures of which are herein incorporated by reference.

5 In some instances the biomass material is treated at a first level to reduce recalcitrance, *e.g.*, utilizing accelerated electrons, to selectively release one or more sugars (*e.g.*, xylose). The biomass can then be treated to a second level to release one or more other sugars (*e.g.*, glucose). Optionally the biomass can be dried between treatments. The treatments can include applying chemical and biochemical treatments to
10 release the sugars. For example, a biomass material can be treated to a level of less than about 20 Mrad (*e.g.*, less than about 15 Mrad, less than about 10 Mrad, less than about 5 Mrad, less than about 2 Mrad) and then treated with a solution of sulfuric acid, containing less than 10% sulfuric acid (*e.g.*, less than about 9%, less than about 8%, less than about 7%, less than about 6%, less than about 5%, less than about 4%, less than
15 about 3%, less than about 2%, less than about 1%, less than about 0.75%, less than about 0.50 %, less than about 0.25%) to release xylose. Xylose, for example that is released into solution, can be separated from solids and optionally the solids washed with a solvent/solution (*e.g.*, with water and/or acidified water). Optionally, the solids can be dried, for example in air and/or under vacuum optionally with heating (*e.g.*, below about
20 150 deg C, below about 120 deg C) to a water content below about 25 wt% (below about 20 wt.%, below about 15 wt.%, below about 10 wt.%, below about 5 wt.%). The solids can then be treated with a level of less than about 30 Mrad (*e.g.*, less than about 25 Mrad, less than about 20 Mrad, less than about 15 Mrad, less than about 10 Mrad, less than about 5 Mrad, less than about 1 Mrad or even not at all) and then treated with an enzyme
25 (*e.g.*, a cellulase) to release glucose. The glucose (*e.g.*, glucose in solution) can be separated from the remaining solids. The solids can then be further processed, for example utilized to make energy or other products (*e.g.*, lignin derived products).

FLAVORS, FRAGRANCES AND COLORANTS

30

Any of the products and/or intermediates described herein, for example, produced by the processes, systems and/or equipment described herein, can be combined with flavors, fragrances, colorants and/or mixtures of these. For example, any one or more of (optionally along with flavors, fragrances and/or colorants) sugars, organic acids, fuels,

polyols, such as sugar alcohols, biomass, fibers and composites can be combined with (e.g., formulated, mixed or reacted) or used to make other products. For example, one or more such product can be used to make soaps, detergents, candies, drinks (e.g., cola, wine, beer, liquors such as gin or vodka, sports drinks, coffees, teas), syrups

5 pharmaceuticals, adhesives, sheets (e.g., woven, none woven, filters, tissues) and/or composites (e.g., boards). For example, one or more such product can be combined with herbs, flowers, petals, spices, vitamins, potpourri, or candles. For example, the formulated, mixed or reacted combinations can have flavors/fragrances of grapefruit, orange, apple, raspberry, banana, lettuce, celery, cinnamon, chocolate, vanilla,

10 peppermint, mint, onion, garlic, pepper, saffron, ginger, milk, wine, beer, tea, lean beef, fish, clams, olive oil, coconut fat, pork fat, butter fat, beef bouillon, legume, potatoes, marmalade, ham, coffee and cheeses.

Flavors, fragrances and colorants can be added in any amount, such as between about 0.001 wt.% to about 30 wt.%, e.g., between about 0.01 to about 20, between about

15 0.05 to about 10, or between about 0.1 wt.% to about 5 wt.%. These can be formulated, mixed and or reacted (e.g., with any one of more product or intermediate described herein) by any means and in any order or sequence (e.g., agitated, mixed, emulsified, gelled, infused, heated, sonicated, and/or suspended). Fillers, binders, emulsifier, antioxidants can also be utilized, for example protein gels, starches and silica.

20 In one embodiment the flavors, fragrances and colorants can be added to the biomass immediately after the biomass is irradiated such that the reactive sites created by the irradiation may react with reactive compatible sites of the flavors, fragrances, and colorants.

The flavors, fragrances and colorants can be natural and/or synthetic materials.

25 These materials can be one or more of a compound, a composition or mixtures of these (e.g., a formulated or natural composition of several compounds). Optionally the flavors, fragrances, antioxidants and colorants can be derived biologically, for example, from a fermentation process (e.g., fermentation of saccharified materials as described herein). Alternatively, or additionally these flavors, fragrances and colorants can be harvested

30 from a whole organism (e.g., plant, fungus, animal, bacteria or yeast) or a part of an organism. The organism can be collected and or extracted to provide color, flavors, fragrances and/or antioxidant by any means including utilizing the methods, systems and equipment described herein, hot water extraction, supercritical fluid extraction, chemical extraction (e.g., solvent or reactive extraction including acids and bases), mechanical

extraction (*e.g.*, pressing, comminuting, filtering), utilizing an enzyme, utilizing a bacteria such as to break down a starting material, and combinations of these methods. The compounds can be derived by a chemical reaction, for example, the combination of a sugar (*e.g.*, as produced as described herein) with an amino acid (Maillard reaction).

- 5 The flavor, fragrance, antioxidant and/or colorant can be an intermediate and or product produced by the methods, equipment or systems described herein, for example and ester and a lignin derived product.

Some examples of flavor, fragrances or colorants are polyphenols. Polyphenols are pigments responsible for the red, purple and blue colorants of many fruits,
 10 vegetables, cereal grains, and flowers. Polyphenols also can have antioxidant properties and often have a bitter taste. The antioxidant properties make these important preservatives. One class of polyphenols are the flavonoids, such as Anthocyanidines, flavanonols, flavan-3-ols, s, flavanones and flavanonols. Other phenolic compounds that can be used include phenolic acids and their esters, such as chlorogenic acid and
 15 polymeric tannins.

Among the colorants inorganic compounds, minerals or organic compounds can be used, for example titanium dioxide, zinc oxide, aluminum oxide, cadmium yellow (*E.g.*, CdS), cadmium orange (*e.g.*, CdS with some Se), alizarin crimson (*e.g.*, synthetic or non-synthetic rose madder), ultramarine (*e.g.*, synthetic ultramarine, natural
 20 ultramarine, synthetic ultramarine violet), cobalt blue, cobalt yellow, cobalt green, viridian (*e.g.*, hydrated chromium(III)oxide), chalcophylite, conichalcite, cornubite, cornwallite and lironite. Black pigments such as carbon black and self-dispersed blacks may be used.

Some flavors and fragrances that can be utilized include ACALEA TBHQ,
 25 ACET C-6, ALLYL AMYL GLYCOLATE, ALPHA TERPINEOL, AMBRETTOLIDE, AMBRINOL 95, ANDRANE, APHERMATE, APPLELIDE, BACDANOL®, BERGAMAL, BETA IONONE EPOXIDE, BETA NAPHTHYL ISO-BUTYL ETHER, BICYCLONONALACTONE, BORNAFIX®, CANTHOXAL, CASHMERAN®, CASHMERAN® VELVET, CASSIFFIX®, CEDRAFIX, CEDRAMBER®, CEDRYL
 30 ACETATE, CELESTOLIDE, CINNAMALVA, CITRAL DIMETHYL ACETATE, CITROLATE™, CITRONELLOL 700, CITRONELLOL 950, CITRONELLOL COEUR, CITRONELLYL ACETATE, CITRONELLYL ACETATE PURE, CITRONELLYL FORMATE, CLARYCET, CLONAL, CONIFERAN, CONIFERAN PURE, CORTEX ALDEHYDE 50% PEOMOSA, CYCLABUTE, CYCLACET®,

CYCLAPROP®, CYCLEMAX™, CYCLOHEXYL ETHYL ACETATE, DAMASCOL,
DELTA DAMASCONE, DIHYDRO CYCLACET, DIHYDRO MYRCENOL,
DIHYDRO TERPINEOL, DIHYDRO TERPINYL ACETATE, DIMETHYL
CYCLORMOL, DIMETHYL OCTANOL PQ, DIMYRCETOL, DIOLA, DIPENTENE,
5 DULCINYL® RECRYSTALLIZED, ETHYL-3-PHENYL GLYCIDATE,
FLEURAMONE, FLEURANIL, FLORAL SUPER, FLORALOZONE, FLORIFFOL,
FRAISTONE, FRUCTONE, GALAXOLIDE® 50, GALAXOLIDE® 50 BB,
GALAXOLIDE® 50 IPM, GALAXOLIDE® UNDILUTED, GALBASCONA,
GERALDEHYDE, GERANIOL 5020, GERANIOL 600 TYPE, GERANIOL 950,
10 GERANIOL 980 (PURE), GERANIOL CFT COEUR, GERANIOL COEUR,
GERANYL ACETATE COEUR, GERANYL ACETATE, PURE, GERANYL
FORMATE, GRISALVA, GUAIYL ACETATE, HELIONAL™, HERBAC,
HERBALIME™, HEXADECANOLIDE, HEXALON, HEXENYL SALICYLATE CIS
3-, HYACINTH BODY, HYACINTH BODY NO. 3, HYDRATROPIC
15 ALDEHYDE.DMA, HYDROXYOL, INDOLAROME, INTRELEVEN ALDEHYDE,
INTRELEVEN ALDEHYDE SPECIAL, IONONE ALPHA, IONONE BETA, ISO
CYCLO CITRAL, ISO CYCLO GERANIOL, ISO E SUPER®, ISOBUTYL
QUINOLINE, JASMAL, JESSEMAL®, KHARISMAL®, KHARISMAL® SUPER,
KHUSINIL, KOAVONE®, KOHINOOL®, LIFFAROMET™, LIMOXAL,
20 LINDENOL™, LYRAL®, LYRAME SUPER, MANDARIN ALD 10% TRI ETH,
CITR, MARITIMA, MCK CHINESE, MEIJIFF™, MELAFLEUR, MELOZONE,
METHYL ANTHRANILATE, METHYL IONONE ALPHA EXTRA, METHYL
IONONE GAMMA A, METHYL IONONE GAMMA COEUR, METHYL IONONE
GAMMA PURE, METHYL LAVENDER KETONE, MONTAVERDI®, MUGUESIA,
25 MUGUET ALDEHYDE 50, MUSK Z4, MYRAC ALDEHYDE, MYRCENYL
ACETATE, NECTARATE™, NEROL 900, NERYL ACETATE, OCIMENE,
OCTACETAL, ORANGE FLOWER ETHER, ORIVONE, ORRINIFF 25%,
OXASPIRANE, OZOFLEUR, PAMPLEFLEUR®, PEOMOSA, PHENOXANOL®,
PICONIA, PRECYCLEMONE B, PRENYL ACETATE, PRISMANTOL, RESEDA
30 BODY, ROSALVA, ROSAMUSK, SANJINOL, SANTALIFF™, SYVERTAL,
TERPINEOL, TERPINOLENE 20, TERPINOLENE 90 PQ, TERPINOLENE RECT.,
TERPINYL ACETATE, TERPINYL ACETATE JAX, TETRAHYDRO, MUGUOL®,
TETRAHYDRO MYRCENOL, TETRAMERAN, TIMBERSILK™, TOBACAROL,
TRIMOFIX® O TT, TRIPLAL®, TRISAMBER®, VANORIS, VERDOX™,

VERDOX™ HC, VERTENEX®, VERTENEX® HC, VERTOPIX® COEUR,
 VERTOLIFF, VERTOLIFF ISO, VIOLIFF, VIVALDIE, ZENOLIDE, ABS INDIA 75
 PCT MIGLYOL, ABS MOROCCO 50 PCT DPG, ABS MOROCCO 50 PCT TEC,
 ABSOLUTE FRENCH, ABSOLUTE INDIA, ABSOLUTE MD 50 PCT BB,
 5 ABSOLUTE MOROCCO, CONCENTRATE PG, TINCTURE 20 PCT, AMBERGRIS,
 AMBRETTE ABSOLUTE, AMBRETTE SEED OIL, ARMOISE OIL 70 PCT
 THUYONE, BASIL ABSOLUTE GRAND VERT, BASIL GRAND VERT ABS MD,
 BASIL OIL GRAND VERT, BASIL OIL VERVEINA, BASIL OIL VIETNAM, BAY
 OIL TERPENELESS, BEESWAX ABS N G, BEESWAX ABSOLUTE, BENZOIN
 10 RESINOID SIAM, BENZOIN RESINOID SIAM 50 PCT DPG, BENZOIN RESINOID
 SIAM 50 PCT PG, BENZOIN RESINOID SIAM 70.5 PCT TEC, BLACKCURRANT
 BUD ABS 65 PCT PG, BLACKCURRANT BUD ABS MD 37 PCT TEC,
 BLACKCURRANT BUD ABS MIGLYOL, BLACKCURRANT BUD ABSOLUTE
 BURGUNDY, BOIS DE ROSE OIL, BRAN ABSOLUTE, BRAN RESINOID,
 15 BROOM ABSOLUTE ITALY, CARDAMOM GUATEMALA CO2 EXTRACT,
 CARDAMOM OIL GUATEMALA, CARDAMOM OIL INDIA, CARROT HEART,
 CASSIE ABSOLUTE EGYPT, CASSIE ABSOLUTE MD 50 PCT IPM, CASTOREUM
 ABS 90 PCT TEC, CASTOREUM ABS C 50 PCT MIGLYOL, CASTOREUM
 ABSOLUTE, CASTOREUM RESINOID, CASTOREUM RESINOID 50 PCT DPG,
 20 CEDROL CEDRENE, CEDRUS ATLANTICA OIL REDIST, CHAMOMILE OIL
 ROMAN, CHAMOMILE OIL WILD, CHAMOMILE OIL WILD LOW LIMONENE,
 CINNAMON BARK OIL CEYLAN, CISTE ABSOLUTE, CISTE ABSOLUTE
 COLORLESS, CITRONELLA OIL ASIA IRON FREE, CIVET ABS 75 PCT PG,
 CIVET ABSOLUTE, CIVET TINCTURE 10 PCT, CLARY SAGE ABS FRENCH
 25 DECOL, CLARY SAGE ABSOLUTE FRENCH, CLARY SAGE C'LESS 50 PCT PG,
 CLARY SAGE OIL FRENCH, COPAIBA BALSAM, COPAIBA BALSAM OIL,
 CORIANDER SEED OIL, CYPRESS OIL, CYPRESS OIL ORGANIC, DAVANA OIL,
 GALBANOL, GALBANUM ABSOLUTE COLORLESS, GALBANUM OIL,
 GALBANUM RESINOID, GALBANUM RESINOID 50 PCT DPG, GALBANUM
 30 RESINOID HERCOLYN BHT, GALBANUM RESINOID TEC BHT, GENTIANE
 ABSOLUTE MD 20 PCT BB, GENTIANE CONCRETE, GERANIUM ABS EGYPT
 MD, GERANIUM ABSOLUTE EGYPT, GERANIUM OIL CHINA, GERANIUM OIL
 EGYPT, GINGER OIL 624, GINGER OIL RECTIFIED SOLUBLE, GUAIAACWOOD
 HEART, HAY ABS MD 50 PCT BB, HAY ABSOLUTE, HAY ABSOLUTE MD 50

- PCT TEC, HEALINGWOOD, HYSSOP OIL ORGANIC, IMMORTELLE ABS YUGO MD 50 PCT TEC, IMMORTELLE ABSOLUTE SPAIN, IMMORTELLE ABSOLUTE YUGO, JASMIN ABS INDIA MD, JASMIN ABSOLUTE EGYPT, JASMIN ABSOLUTE INDIA, ASMIN ABSOLUTE MOROCCO, JASMIN ABSOLUTE
- 5 SAMBAC, JONQUILLE ABS MD 20 PCT BB, JONQUILLE ABSOLUTE France, JUNIPER BERRY OIL FLG, JUNIPER BERRY OIL RECTIFIED SOLUBLE, LABDANUM RESINOID 50 PCT TEC, LABDANUM RESINOID BB, LABDANUM RESINOID MD, LABDANUM RESINOID MD 50 PCT BB, LAVANDIN ABSOLUTE H, LAVANDIN ABSOLUTE MD, LAVANDIN OIL ABRIAL ORGANIC,
- 10 LAVANDIN OIL GROSSO ORGANIC, LAVANDIN OIL SUPER, LAVENDER ABSOLUTE H, LAVENDER ABSOLUTE MD, LAVENDER OIL COUMARIN FREE, LAVENDER OIL COUMARIN FREE ORGANIC, LAVENDER OIL MAILLETTE ORGANIC, LAVENDER OIL MT, MACE ABSOLUTE BB, MAGNOLIA FLOWER OIL LOW METHYL EUGENOL, MAGNOLIA FLOWER
- 15 OIL, MAGNOLIA FLOWER OIL MD, MAGNOLIA LEAF OIL, MANDARIN OIL MD, MANDARIN OIL MD BHT, MATE ABSOLUTE BB, MOSS TREE ABSOLUTE MD TEX IFRA 43, MOSS-OAK ABS MD TEC IFRA 43, MOSS-OAK ABSOLUTE IFRA 43, MOSS-TREE ABSOLUTE MD IPM IFRA 43, MYRRH RESINOID BB, MYRRH RESINOID MD, MYRRH RESINOID TEC, MYRTLE OIL IRON FREE,
- 20 MYRTLE OIL TUNISIA RECTIFIED, NARCISSE ABS MD 20 PCT BB, NARCISSE ABSOLUTE FRENCH, NEROLI OIL TUNISIA, NUTMEG OIL TERPENELESS, OEILLET ABSOLUTE, OLIBANUM RESINOID, OLIBANUM RESINOID BB, OLIBANUM RESINOID DPG, OLIBANUM RESINOID EXTRA 50 PCT DPG, OLIBANUM RESINOID MD, OLIBANUM RESINOID MD 50 PCT DPG,
- 25 OLIBANUM RESINOID TEC, OPOPONAX RESINOID TEC, ORANGE BIGARADE OIL MD BHT, ORANGE BIGARADE OIL MD SCFC, ORANGE FLOWER ABSOLUTE TUNISIA, ORANGE FLOWER WATER ABSOLUTE TUNISIA, ORANGE LEAF ABSOLUTE, ORANGE LEAF WATER ABSOLUTE TUNISIA, ORRIS ABSOLUTE ITALY, ORRIS CONCRETE 15 PCT IRONE, ORRIS
- 30 CONCRETE 8 PCT IRONE, ORRIS NATURAL 15 PCT IRONE 4095C, ORRIS NATURAL 8 PCT IRONE 2942C, ORRIS RESINOID, OSMANTHUS ABSOLUTE, OSMANTHUS ABSOLUTE MD 50 PCT BB, PATCHOULI HEART N°3, PATCHOULI OIL INDONESIA, PATCHOULI OIL INDONESIA IRON FREE, PATCHOULI OIL INDONESIA MD, PATCHOULI OIL REDIST, PENNYROYAL

HEART, PEPPERMINT ABSOLUTE MD, PETITGRAIN BIGARADE OIL TUNISIA,
 PETITGRAIN CITRONNIER OIL, PETITGRAIN OIL PARAGUAY TERPENELESS,
 PETITGRAIN OIL TERPENELESS STAB, PIMENTO BERRY OIL, PIMENTO LEAF
 OIL, RHODINOL EX GERANIUM CHINA, ROSE ABS BULGARIAN LOW
 5 METHYL EUGENOL, ROSE ABS MOROCCO LOW METHYL EUGENOL, ROSE
 ABS TURKISH LOW METHYL EUGENOL, ROSE ABSOLUTE, ROSE ABSOLUTE
 BULGARIAN, ROSE ABSOLUTE DAMASCENA, ROSE ABSOLUTE MD, ROSE
 ABSOLUTE MOROCCO, ROSE ABSOLUTE TURKISH, ROSE OIL BULGARIAN,
 ROSE OIL DAMASCENA LOW METHYL EUGENOL, ROSE OIL TURKISH,
 10 ROSEMARY OIL CAMPHOR ORGANIC, ROSEMARY OIL TUNISIA,
 SANDALWOOD OIL INDIA, SANDALWOOD OIL INDIA RECTIFIED,
 SANTALOL, SCHINUS MOLLE OIL, ST JOHN BREAD TINCTURE 10 PCT,
 STYRAX RESINOID, STYRAX RESINOID, TAGETE OIL, TEA TREE HEART,
 TONKA BEAN ABS 50 PCT SOLVENTS, TONKA BEAN ABSOLUTE, TUBEROSE
 15 ABSOLUTE INDIA, VETIVER HEART EXTRA, VETIVER OIL HAITI, VETIVER
 OIL HAITI MD, VETIVER OIL JAVA, VETIVER OIL JAVA MD, VIOLET LEAF
 ABSOLUTE EGYPT, VIOLET LEAF ABSOLUTE EGYPT DECOL, VIOLET LEAF
 ABSOLUTE FRENCH, VIOLET LEAF ABSOLUTE MD 50 PCT BB, WORMWOOD
 OIL TERPENELESS, YLANG EXTRA OIL, YLANG III OIL and combinations of
 20 these.

The colorants can be among those listed in the Color Index International by the
 Society of Dyers and Colourists. Colorants include dyes and pigments and include those
 commonly used for coloring textiles, paints, inks and inkjet inks. Some colorants that
 can be utilized include carotenoids, arylide yellows, diarylide yellows, β -naphthols,
 25 naphthols, benzimidazolones, disazo condensation pigments, pyrazolones, nickel azo
 yellow, phthalocyanines, quinacridones, perylenes and perinones, isoindolinone and
 isoindoline pigments, triarylcarbonium pigments, diketopyrrolo-pyrrole pigments,
 thioindigoids. Carotenoids include, for example, alpha-carotene, beta-carotene, gamma-
 carotene, lycopene, lutein and astaxanthin Annatto extract, Dehydrated beets (beet
 30 powder), Canthaxanthin, Caramel, β -Apo-8'-carotenal, Cochineal extract, Carmine,
 Sodium copper chlorophyllin, Toasted partially defatted cooked cottonseed flour,
 Ferrous gluconate, Ferrous lactate, Grape color extract, Grape skin extract (enocianina),
 Carrot oil, Paprika, Paprika oleoresin, Mica-based pearlescent pigments, Riboflavin,
 Saffron, Titanium dioxide, Tomato lycopene extract; tomato lycopene concentrate,

Turmeric, Turmeric oleoresin, FD&C Blue No. 1, FD&C Blue No. 2, FD&C Green No. 3, Orange B, Citrus Red No. 2, FD&C Red No. 3, FD&C Red No. 40, FD&C Yellow No. 5, FD&C Yellow No. 6, Alumina (dried aluminum hydroxide), Calcium carbonate, Potassium sodium copper chlorophyllin (chlorophyllin-copper complex),
 5 Dihydroxyacetone, Bismuth oxychloride, Ferric ammonium ferrocyanide, Ferric ferrocyanide, Chromium hydroxide green, Chromium oxide greens, Guanine, Pyrophyllite, Talc, Aluminum powder, Bronze powder, Copper powder, Zinc oxide, D&C Blue No. 4, D&C Green No. 5, D&C Green No. 6, D&C Green No. 8, D&C Orange No. 4, D&C Orange No. 5, D&C Orange No. 10, D&C Orange No. 11, FD&C
 10 Red No. 4, D&C Red No. 6, D&C Red No. 7, D&C Red No. 17, D&C Red No. 21, D&C Red No. 22, D&C Red No. 27, D&C Red No. 28, D&C Red No. 30, D&C Red No. 31, D&C Red No. 33, D&C Red No. 34, D&C Red No. 36, D&C Red No. 39, D&C Violet No. 2, D&C Yellow No. 7, Ext. D&C Yellow No. 7, D&C Yellow No. 8, D&C Yellow No. 10, D&C Yellow No. 11, D&C Black No. 2, D&C Black No. 3 (3), D&C Brown No.
 15 1, Ext. D&C, Chromium-cobalt-aluminum oxide, Ferric ammonium citrate, Pyrogallol, Logwood extract, 1,4-Bis[(2-hydroxy-ethyl)amino]-9,10-anthracenedione bis(2-propenoic)ester copolymers, 1,4-Bis [(2-methylphenyl)amino] -9,10-anthracenedione, 1,4-Bis[4- (2-methacryloxyethyl) phenylamino] anthraquinone copolymers, Carbazole violet, Chlorophyllin-copper complex, Chromium-cobalt-aluminum oxide,, C.I. Vat
 20 Orange 1, 2-[[2,5-Diethoxy- 4-[(4-methylphenyl)thiol] phenyl]azo] -1,3,5-benzenetriol, 16,23-Dihydrodinaphtho [2,3-a:2',3'-i] naphth [2',3':6,7] indolo [2,3-c] carbazole-5,10,15,17,22,24-hexone, N,N'-(9,10-Dihydro- 9,10-dioxo- 1,5-anthracenediyl) bisbenzamide, 7,16-Dichloro- 6,15-dihydro- 5,9,14,18-anthrazinetetrone, 16,17-Dimethoxydinaphtho (1,2,3-cd:3',2',1'-lm) perylene-5,10-dione, Poly(hydroxyethyl
 25 methacrylate) -dye copolymers(3), Reactive Black 5, Reactive Blue 21, Reactive Orange 78, Reactive Yellow 15, Reactive Blue No. 19, Reactive Blue No. 4, C.I. Reactive Red 11, C.I. Reactive Yellow 86, C.I. Reactive Blue 163, C.I. Reactive Red 180, 4-[(2,4-dimethylphenyl)azo]- 2,4-dihydro- 5-methyl-2-phenyl- 3H-pyrazol-3-one (solvent Yellow 18), 6-Ethoxy-2- (6-ethoxy-3-oxobenzo[b] thien-2(3H)- ylidene)
 30 benzo[b]thiophen- 3(2H)-one, Phthalocyanine green, Vinyl alcohol/methyl methacrylate-dye reaction products, C.I. Reactive Red 180, C.I. Reactive Black 5, C.I. Reactive Orange 78, C.I. Reactive Yellow 15, C.I. Reactive Blue 21, Disodium 1-amino-4-[[4-[(2-bromo-1-oxoallyl)amino]-2-sulphonatophenyl]amino]-9,10-dihydro-9,10-

dioxoanthracene-2-sulphonate (Reactive Blue 69), D&C Blue No. 9, [Phthalocyaninato(2-)] copper and mixtures of these.

Other than in the examples herein, or unless otherwise expressly specified, all of the numerical ranges, amounts, values and percentages, such as those for amounts of materials, elemental contents, times and temperatures of reaction, ratios of amounts, and others, in the following portion of the specification and attached claims may be read as if prefaced by the word “about” even though the term “about” may not expressly appear with the value, amount, or range. Accordingly, unless indicated to the contrary, the numerical parameters set forth in the following specification and attached claims are approximations that may vary depending upon the desired properties sought to be obtained by the present invention. At the very least, and not as an attempt to limit the application of the doctrine of equivalents to the scope of the claims, each numerical parameter should at least be construed in light of the number of reported significant digits and by applying ordinary rounding techniques.

Notwithstanding that the numerical ranges and parameters setting forth the broad scope of the invention are approximations, the numerical values set forth in the specific examples are reported as precisely as possible. Any numerical value, however, inherently contains error necessarily resulting from the standard deviation found in its underlying respective testing measurements. Furthermore, when numerical ranges are set forth herein, these ranges are inclusive of the recited range end points (*e.g.*, end points may be used). When percentages by weight are used herein, the numerical values reported are relative to the total weight.

Also, it should be understood that any numerical range recited herein is intended to include all sub-ranges subsumed therein. For example, a range of “1 to 10” is intended to include all sub-ranges between (and including) the recited minimum value of 1 and the recited maximum value of 10, that is, having a minimum value equal to or greater than 1 and a maximum value of equal to or less than 10. The terms “one,” “a,” or “an” as used herein are intended to include “at least one” or “one or more,” unless otherwise indicated.

Any patent, publication, or other disclosure material, in whole or in part, that is said to be incorporated by reference herein is incorporated herein only to the extent that the incorporated material does not conflict with existing definitions, statements, or other disclosure material set forth in this disclosure. As such, and to the extent necessary, the disclosure as explicitly set forth herein supersedes any conflicting material incorporated

herein by reference. Any material, or portion thereof, that is said to be incorporated by reference herein, but which conflicts with existing definitions, statements, or other disclosure material set forth herein will only be incorporated to the extent that no conflict arises between that incorporated material and the existing disclosure material.

5 While this invention has been particularly shown and described with references to preferred embodiments thereof, it will be understood by those skilled in the art that various changes in form and details may be made therein without departing from the scope of the invention encompassed by the appended claims.

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APPENDIX

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5. Biomass Conversion Technologies

In the context of this document, biomass conversion refers to the process of converting biomass into energy that will in turn be used to generate electricity and/or heat. The principal categories of biomass conversion technologies for power and heat production are **direct-fired** and **gasification** systems. Within the direct-fired category, specific technologies include stoker boilers, fluidized bed boilers, and cofiring. Within the gasification category, specific technologies include fixed bed gasifiers and fluidized bed gasifiers. Anaerobic digesters are also considered a biomass conversion technology; however, extensive information about digesters is readily available from EPA's AgSTAR Program <www.epa.gov/agstar> and therefore, will not be discussed within this chapter.

Biomass power systems are typically below 50 MW in size, compared to coal-fired plants, which are in the 100- to 1,000-MW range. Most of today's biomass power plants are **direct-fired systems**. The biomass fuel is burned in a boiler to produce high-pressure steam that is used to power a steam turbine-driven power generator. In many applications, steam is extracted from the turbine at medium pressures and temperatures and is used for process heat, space heating, or space cooling. **Cofiring** involves substituting biomass for a portion of the coal in an existing power plant boiler. It is the most economic near-term option for introducing new biomass power generation. Because much of the existing power plant equipment can be used without major modifications, cofiring is far less expensive than building a new biomass power plant. Compared to the coal it replaces, biomass reduces SO₂, NO_x, CO₂, and other air emissions.

Biomass **gasification** systems operate by heating biomass in an environment where the solid biomass breaks down to form a flammable gas. The gas produced—synthesis gas, or syngas—can be cleaned, filtered, and then burned in a gas turbine in simple or combined-cycle mode, comparable to LFG or biogas produced from an anaerobic digester. In smaller systems, the syngas can be fired in reciprocating engines, microturbines, Stirling engines, or fuel cells. Gasification technologies using biomass byproducts are popular in the pulp and paper industry where they improve chemical recovery and generate process steam and electricity at higher efficiencies and with lower capital costs than conventional technologies. Pulp and paper industry byproducts that can be gasified include hogged wood, bark, and spent black liquor.

Table 5-1 provides a summary of biomass conversion technologies for producing heat and power.

Table 5-1. Summary of Biomass CHP Conversion Technologies

Biomass Conversion Technology	Common Fuel Types	Feed Size	Moisture Content	Capacity Range
Stoker grate, underfire stoker boilers	Sawdust, bark, chips, hog fuel, shavings, end cuts, sander dust	0.25–2 in.	10–50%	4 to 300 MW (many in the 20 to 50 MW range)
Fluidized bed boiler	Wood residue, peat, wide variety of fuels	< 2 in.	< 60%	Up to 300 MW (many in the 20 to 25 MW range)
Cofiring—pulverized coal boilers	Sawdust, bark, shavings, sander dust	< 0.25 in.	< 25%	Up to 1000 MW
Cofiring—stoker, fluidized bed boilers	Sawdust, bark, shavings, hog fuel	< 2 in.	10–50%	Up to 300 MW
Fixed bed gasifier	Chipped wood or hog fuel, rice hulls, shells, sewage sludge	0.25–4 in.	< 20%	Up to 50 MW
Fluidized bed gasifier	Most wood and agriculture residues	0.25–2 in.	15–30%	Up to 25 MW

Source: Based on Wright, 2006.

Modular systems employ some of the same technologies mentioned above, but on a smaller scale that is more applicable to farms, institutional buildings, and small industry. A number of modular systems are now under development and could be most useful in remote areas where biomass is abundant and electricity is scarce.

5.1 Direct-Fired Systems

The most common utilization of solid fuel biomass is direct combustion with the resulting hot flue gases producing steam in a boiler—a technology that goes back to the 19th century. Boilers today burn a variety of fuels and continue to play a major role in industrial process heating, commercial and institutional heating, and electricity generation. Boilers are differentiated by their configuration, size, and the quality of the steam or hot water produced. Boiler size is most often measured by the fuel input in MMBtu per hour (MMBtu/hr), but it may also be measured by output in pounds of steam per hour. Because large boilers are often used to generate electricity, it can also be useful to relate boiler size to power output in electric generating applications. Using typical boiler and steam turbine generating efficiencies, 100 MMBtu/hr heat input provides about 10 MW electric output.

The two most commonly used types of boilers for biomass firing are stoker boilers and fluidized bed boilers. Either of these can be fueled entirely by biomass fuel or cofired with a combination of biomass and coal. The efficiency, availability, operating issues, equipment and installed costs, O&M requirements and costs, and commercial status of each of these options are discussed below.

5.1.1 Boilers

Characterization

Stoker Boilers

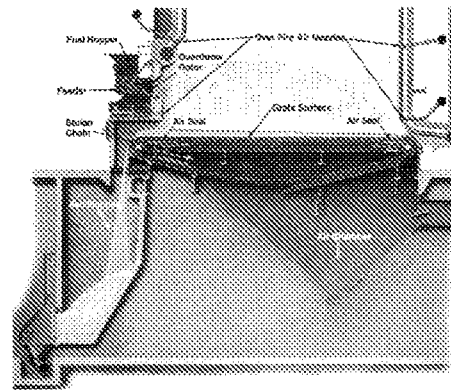
Stoker boilers employ direct fire combustion of solid fuels with excess air, producing hot flue gases, which then produce steam in the heat exchange section of the boiler. The steam is used directly for heating purposes or passed through a steam turbine generator to produce electric power. Stoker-fired boilers were first introduced in the 1920s for coal; in the late 1940s the Detroit Stoker Company installed the first traveling grate spreader stoker boiler for wood. Mechanical stokers are the traditional technology that has been used to automatically supply solid fuels to a boiler. All stokers are designed to feed fuel onto a grate where it burns with air passing up through it. The stoker is located within the furnace section of the boiler and is designed to remove the ash residue after combustion. Stoker units use mechanical means to shift and add fuel to the fire that burns on and above the grate located near the base of the boiler. Heat is transferred from the fire and combustion gases to water tubes on the walls of the boiler.

Modern mechanical stokers consist of four elements, 1) a fuel admission system, 2) a stationary or moving grate assembly that supports the burning fuel and provides a pathway for the primary combustion air, 3) an overfire air system that supplies additional air to complete combustion and minimize atmospheric emissions, and 4) an ash discharge system. Figure 5-1 illustrates the different sections of a stoker boiler.

A successful stoker installation requires selecting the correct size and type of stoker for the fuel being used and for the load conditions and capacity being served. Stoker boilers are typically described by their method of adding and distributing fuel. There are two general types of systems—**underfeed** and **overfeed**. Underfeed stokers supply both the fuel and air from under the grate, while overfeed stokers supply fuel from above the grate and air from below. Overfeed stokers are further divided into two types—**mass feed** and **spreader**. In the mass feed stoker, fuel is continuously fed onto one end of the grate

surface and travels horizontally across the grate as it burns. The residual ash is discharged from the opposite end. Combustion air is introduced from below the grate and moves up through the burning bed of fuel. In the spreader stoker, the most common type of stoker boiler, combustion air is again introduced primarily from below the grate but the fuel is thrown or spread uniformly across the grate area. The finer particles of fuel combust in suspension as they fall against the upward moving air. The remaining heavier pieces fall and burn on the grate surface, with any residual ash removed from the discharge end of the grate. Chain grate, traveling grate, and water-cooled vibrating grate stokers are other less common configurations that use various means to maintain an even, thin bed of burning fuel on the grate. Other specialized stoker boilers include balanced draft, cyclone-fired, fixed bed, shaker hearth, tangential-fired, and, consequently, the maximum steam generation rates are limited to about 100,000 pounds per hour (lb/hr), for wood or other biomass fuels.

Figure 5-1. Cut-Away View of a Travelling Grate Stoker Boiler

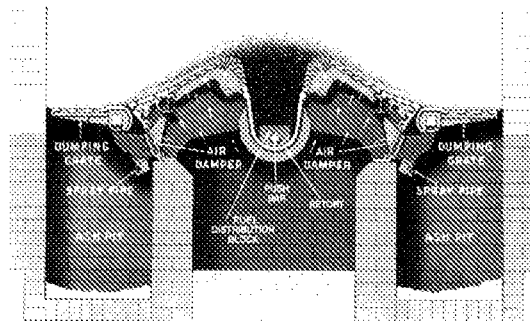


Source: ORNL, 2002.

Underfeed Stokers

Underfeed stokers supply both fuel and primary combustion air from beneath the grate so that the top of the fuel pile is not cooled by cold and moist fuel or cold air. The fuel is moved into a hopper and onto the grate by either a screw- or ram-driven mechanism. Underfeed stokers push the fuel into the bottom of the bed of fuel while heat causes volatilization and complete combustion of the fuel by the time it rises to the top of the bed as ash and is discharged. As the fuel moves out over the grate where it is exposed to air and radiant heat, it begins to burn and transfer heat to the water tubes. As with any combustion process, ash accumulates as the fuel is burned. The two basic types of underfeed stokers are: 1) the horizontal-feed, side-ash discharge type and 2) the gravity-feed, rear-ash discharge type. A cross-section of an underfeed, side-ash discharge stoker is shown in **Figure 5-2**. The demand for underfeed stokers has diminished due to cost and environmental considerations. Underfeed stokers are best suited for relatively dry fuel (under 40 to 45 percent moisture.)

Figure 5-2. Cross Section of Underfeed, Side-Ash Discharge Stoker

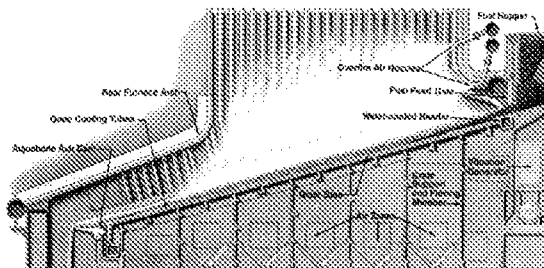


Source: ORNL, 2002.

Overfeed Stokers

Overfeed stokers are generally classified by the way the fuel is distributed and burned within the boiler. The primary designations are mass-feed or spreader stokers. Mass-feed stokers introduce fuel continuously at one end of a grate. As the fuel moves into the boiler, it falls onto the grate by gravity. To control the amount of fuel that enters the boiler, a gate can be moved up or down, or the speed at which the fuel moves beneath the gate can be adjusted. Inside the boiler, the fuel burns as it travels along the grate. Primary combustion air flows upward from beneath the grate and through the burning bed of fuel, allowing for complete combustion. Any ash that remains on the grate is then discharged at the opposite end of the system. The two primary mass-feed stokers are 1) water-cooled vibrating grate and 2) moving (chain and traveling) grate stokers. A cross-section of an overfeed, water-cooled vibrating grate mass-feed stoker is presented in Figure 5-3.

Figure 5-3. Cross Section of Overfeed, Water-Cooled, Vibrating-Grate, Mass-Feed Stoker



Source: ORNL, 2002.

Spreader Stokers

Spreader stokers are the most commonly used stokers because of their versatility. They are capable of distributing fuel evenly and to a uniform depth over the entire grate surface by using a device that propels the individual fuel particles into the air above the grate. Methods used to propel the fuel particles include air injection and underthrow and overthrow rotors. As the fuel is thrown into the boiler, fine particles ignite and burn while suspended in the combustion air. Due to suspension burning, response times of spreader stokers are better than for mass feed or underfeed stokers. The coarser particles that fall onto the grate end up burning in a thin bed of fuel on the grate. Primary combustion air is supplied from beneath the grate. Because the fuel is evenly distributed across the active grate area, the combustion air is uniformly distributed under and through the grate. A portion of the total combustion air is admitted through ports above the grate as overfire air, completing the combustion process. Grates for spreader stokers are generally designed to move rather than remain stationary. Therefore, traveling grates, air-cooled vibrating grates, and water-cooled vibrating grates are designs that have been used effectively. Modern boilers with spreader stokers incorporate:

- Equipment that distributes fuel uniformly over the grate.
- Specially designed air-metering grates.
- Dust collection and reinjection equipment.
- Forced draft fans for both undergrate and overfire air.
- Combustion controls to coordinate fuel and air supply with steam demand.⁵⁰

⁵⁰ ORNL, 2002.

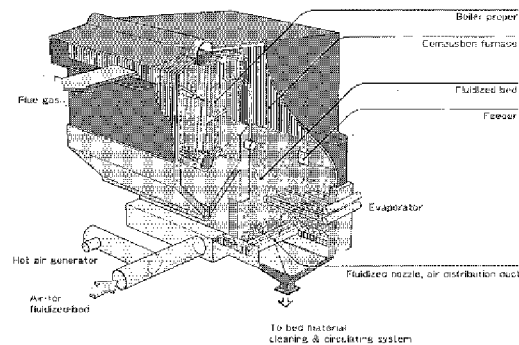
Along with the fuel feed system and furnace section geometry, air system design plays an important role in efficient and complete combustion of biomass fuels in stoker boilers. Excess air for bark, wood, and most biomass fuels is set at 25 percent or above for stoker firing. Because biomass fuels are typically highly volatile on a dry basis, are heterogeneous in size, and more often burn in suspension compared to coal, biomass combustion air systems are designed to provide more overfire air than those used for coal. Modern designs use undergrate and overfire quantities of 40 and 60 percent, respectively.

Fluidized Bed Boilers

Fluidized bed boilers are the most recent type of boiler developed for solid fuel combustion. The primary driving force for development of fluidized bed combustion is reduced SO_2 and NO_x emissions from coal combustion. As the technology developed, it became apparent that the process could efficiently burn biomass and other low-grade fuels that are difficult or impractical to burn with conventional methods.

In this method of combustion, fuel is burned in a bed of hot inert, or incombustible, particles suspended by an upward flow of combustion air that is injected from the bottom of the combustor to keep the bed in a floating or “fluidized” state. The scrubbing action of the bed material on the fuel enhances the combustion process by stripping away the CO_2 and solids residue (char) that normally forms around the fuel particles. This process allows oxygen to reach the combustible material more readily and increases the rate and efficiency of the combustion process. One advantage of mixing in the fluidized bed is that it allows a more compact design than in conventional water tube boiler designs. Natural gas or fuel oil can also be used as a start-up fuel to preheat the fluidized bed or as an auxiliary fuel when additional heat is required. The effective mixing of the bed makes fluidized bed boilers well-suited to burn solid refuse, wood waste, waste coals, and other non-standard fuels. **Figure 5-4** shows the components of a fluidized bed combustion boiler.

Figure 5-4. Cut-Away View of a Fluidized Bed Combustion Boiler



Source: Babcock & Wilcox, 2005.

The fluidized bed combustion process provides a means for efficiently mixing fuel with air for combustion. When fuel is introduced to the bed, it is quickly heated above its ignition temperature, ignites, and becomes part of the burning mass. The flow of air and fuel to the dense bed is controlled so that the desired amount of heat is released to the furnace section on a continuous basis. Typically, biomass is burned with 20 percent or higher excess air. Only a small fraction of the bed is combustible material; the remainder is comprised of inert material, such as sand. This inert material provides a large inventory of heat in the furnace section, dampening the effect of brief fluctuations in fuel supply or heating value on boiler steam output.

Fuels that contain a high concentration of ash, sulfur, and nitrogen can be burned efficiently in fluidized bed boilers while meeting stringent emission limitations. Due to long residence time and high intensity of mass transfer, fuel can be efficiently burned in a fluidized bed combustor at temperatures

considerably lower than in conventional combustion processes (1,400 to 1,600° F compared to 2,200° F for a spreader stoker boiler). The lower temperatures produce less NO_x, a significant benefit with high nitrogen-content wood and biomass fuels. SO₂ emissions from wood waste and biomass are generally insignificant, but where sulfur contamination of the fuel is an issue, limestone can be added to the fluid bed to achieve a high degree of sulfur capture. Fuels that are typically contaminated with sulfur include construction debris and some paper mill sludges.

Fluidized bed boilers are categorized as either atmospheric or pressurized units. Atmospheric fluidized bed boilers are further divided into bubbling-bed and circulating-bed units; the fundamental difference between bubbling-bed and circulating-bed boilers is the fluidization velocity (higher for circulating). Circulating fluidized bed boilers separate and capture fuel solids entrained in the high-velocity exhaust gas and return them to the bed for complete combustion. Atmospheric-pressure bubbling fluidized bed boilers are most commonly used with biomass fuels. The type of fluid bed selected is a function of the as-specified heating value of the biomass fuel. Bubbling bed technology is generally selected for fuels with lower heating values. The circulating bed is most suitable for fuels of higher heating values.

In a pressurized fluidized bed boiler, the entire fluidized bed combustor is encased inside a large pressure vessel. Burning solid fuels in a pressurized fluidized bed boiler produces a high-pressure stream of combustion gases. After the combustion gases pass through a hot gas cleanup system, they are fed into a gas turbine to make electricity, and the heat in the hot exhaust gas stream can be recovered to boil water for a steam turbine. Therefore, a pressurized fluidized bed boiler is more efficient, but also more complicated and expensive. Capital costs of pressurized fluidized bed combustion technology are higher than atmospheric fluidized beds.

Efficiency

Boiler efficiency is defined as the percentage of the fuel energy that is converted to steam energy. Major efficiency factors in biomass combustion are moisture content of the fuel, excess air introduced into the boiler, and the percentage of uncombusted or partially combusted fuel. According to the Council of Industrial Boiler Owners (CIBO), the general efficiency range of stoker and fluidized bed boilers is between 65 and 85 percent efficient.⁵¹ Fuel type and availability have a major effect on efficiency because fuels with high heating values and low moisture content can yield efficiencies up to 25 percent higher than fuels having low heating values and high-moisture contents.

Biomass boilers are typically run with a considerable amount of excess air so that they can achieve complete combustion, but this has a negative impact on efficiency. A CIBO rule of thumb indicates that boiler efficiency can be increased 1 percent for each 15 percent reduction in excess air.⁵²

Table 5-2 compares the efficiency of a biomass stoker and a fluidized bed boiler that are operated with 50 percent excess air with a final flue gas exit temperature of 350° F. The efficiencies are estimated based on the heat-loss method, which is a way of determining boiler efficiency by measuring the individual heat losses (expressed as a percent of heat input) and subtracting them from 100 percent. As can be seen in the table, the largest energy loss in a boiler is the heat that leaves the stack. This loss could amount to as much as 30 to 35 percent of the fuel input in older, poorly maintained boilers. The table shows that decreasing fuel moisture content from 30 to 0 percent increases thermal efficiency by about 6 percentage points. This estimate assumes that the air-fuel ratio is maintained by adjusting air input based on the input moisture content. If the quantity of air is not reduced when wetter fuel enters the boiler then efficiency will drop even more as fuel moisture is increased.

⁵¹ Council of Industrial Boiler Owners, 1997.

⁵² ORNL, 2002.

The primary difference in efficiency between a stoker boiler and a fluidized bed boiler is the amount of fuel that remains unburned. As shown in Table 5-2, the efficiency of fluidized bed boilers compares favorably with stoker boilers due to lower combustion losses. Stoker boilers can have 30 to 40 percent carbon in the ash and additional volatiles and CO in the flue gases, while fluidized bed boiler systems typically achieve nearly 100 percent fuel combustion. The turbulence in the combustor combined with the thermal inertia of the bed material provide for complete, controlled, and uniform combustion. These factors are key to maximizing the thermal efficiency, minimizing char, and controlling emissions.

Table 5-2. Biomass Boiler Efficiency as a Function of Input Fuel and Combustion Characteristics

Characteristics	Biomass Stoker		Biomass Fluidized Bed	
	Dry	As Received	Dry	As Received
Excess air (%)	50	50	50	50
Dry flue gas (lb/lb fuel)	15.25	10.675	15.25	10.675
Final exhaust temp (°F)	350	350	350	350
High heating value (HHV) of the fuel (Btu/lb)	8,500	5,950	8,500	5,950
Moisture content of fuel (%)	0	30	0	30
Hydrogen percent in the fuel (%)	4.59	3.21	4.59	3.21
Efficiency Losses				
Dry flue gas losses (%)	11.63	11.63	11.63	11.63
Moisture in fuel (%)	0.00	5.90	0.00	5.90
Latent heat (%)	5.69	5.69	5.69	5.69
Unburned fuel (%) (1)	3.50	3.50	0.25	0.25
Radiation and miscellaneous (%) (2)	2.03	2.03	2.03	2.03
Total Combustion Losses (%)	22.85	28.74	19.60	25.49
Boiler Efficiency HHV Basis (%)	77.15	71.26	80.40	74.51

(1) Estimated

(2) Includes radiation, moisture in air, and other miscellaneous issues.

When considering factors that influence boiler performance, it should be noted that efficiency is not constant throughout the entire operating range of a boiler. Peak efficiency generally occurs at a particular boiler output that is determined by design characteristics. Whenever boiler operations deviate from this output, the resulting performance is usually below peak efficiency. Operating continuously at peak efficiency is not practical due to seasonal demands, load variations and fuel property variations; however, operating at a steady load and avoiding cyclic or on-off operation can improve efficiency.

Operating Availability⁵³

Typically, both stoker and fluidized boilers are designed for continuous operation, and design performance is in the 90+ percent availability range. Seasonal variability in fuel availability and/or quality can affect the plant availability, but this is a feedstock issue, not an issue of boiler performance. A well

⁵³ The availability of a power generation system is the percentage of time that the system can operate, or is "available" to operate. Both planned maintenance and unplanned outages have a negative effect upon system availability. Therefore an availability of 100% would represent a system that never broke down or needed maintenance (impossible to achieve in real operation).

designed biomass steam system has a reasonable expectation of operating in the 92 to 98 percent availability range.⁵⁴

Operating Advantages and Disadvantages

Stoker and fluidized bed boilers have specific operating advantages and disadvantages with biomass fuels depending on the fuel characteristics and site requirements. Biomass fuels are extremely variable in terms of heating value, moisture content, and other factors that affect combustion. Wood and most other biomass fuels are composed primarily of cellulose and moisture. As discussed previously, the high proportion of moisture is significant because it acts as a heat sink during the combustion process. The latent heat of evaporation depresses flame temperature, taking heat energy away from steam production, and contributing to the difficulty of efficiently burning biomass fuels. Cellulose, in addition to containing the chemical energy released in combustion, contains fuel-bound oxygen. This oxygen decreases the theoretical air requirements for combustion and, accordingly, the amount of nitrogen included in the products of combustion. A few general guidelines for direct firing of wood and biomass in boilers include:

- Maintain stable combustion, which can be achieved in most water-cooled boilers with fuel moisture contents as high as 65 percent by weight, as received.
- Use of preheated combustion air reduces the time required for fuel drying prior to ignition and is essential to spreader stoker combustion systems. Design air temperatures will vary directly with moisture content.
- A high proportion of the combustible content of wood and other biomass fuels burns in the form of volatile compounds. A large proportion of the combustion air requirement, therefore, is added above the fuel in stoker and other conventional combustion boilers as overfire air.
- Solid chars produced in the initial stages of combustion of biomass fuels are of very low density. Conservative selection of furnace section size is used to reduce gas velocity and keep char entrainment into the flue gases and possibly out the stack at acceptable levels.

To ensure smooth fuel feeding, biomass fuels have to be carefully sized and processed. As discussed above, the moisture content of wood and other biomass waste can vary over a wide range, from 10 percent to more than 60 percent. To ensure steady heat input into the boiler using volumetric feeders, efficient homogenization of fuel with different moisture contents at the fuel yard is a necessity.

Biomass-based fuels can increase the risk of slagging and fouling of heat transfer surfaces and, in some cases, the risk of fireside corrosion as well. Potassium ash content is relatively high in fresh wood, green particles, and fast-growing biomass, which causes the ash to melt at low temperatures and leads to a tendency for fouling and slagging. Additionally, biomass fuels can contain chlorine, which, together with alkalis, can induce aggressive corrosion.

Table 5-3 provides a comparison of combustion characteristics and fuel issues for stoker and fluidized bed boilers. Stoker boilers have been around for a long time and are a relatively basic technology, whereas fluidized bed technology is newer and more complex, but offers more flexibility and operating control. Fluidized bed systems offer significant operating flexibility because they can operate under a wide range of load conditions. The thermal inertia of the bed material allows it to withstand changes in moisture and heating content of the fuel without negative impacts. Additionally, the low fuel

⁵⁴ Energy Products of Idaho, a company that provides fluidized bed boilers, has reported operating availabilities of 98 percent for their units, <www.energyproducts.com/fluidized_bed_combustors.htm>.

inventory present in the unit makes it responsive to variable loads. Another advantage is that the fluidized bed can also maintain efficiency during system turn-down. Fluidized bed manufacturers have reported that the operating flexibility of their units has allowed their customers to take advantage of utility incentive programs for generation that follows electric demand.⁵⁵

Table 5-3. Comparison of Stoker and Fluidized Bed Boilers

Feature	Boiler Type	
	Stoker	Fluidized Bed
Combustion Mechanism		
Flow of solid fuel	Transported on stoker	Fluidized by combustion air and circulated through the combustion chamber and cyclone
Combustion zone	On the stoker	Entire area of the combustion furnace
Mass transfer	Slow	Active vertical movement-mass and heat transfer
Combustion Control		
Responsiveness	Slow response	Quick response
Excess air control	Difficult	Possible
Fuel Issues		
Applicability to various fuels	Fair	High
Fuel pretreatment	Generally not necessary	Lumps must be crushed
Environmental Factors		
Low sulfur oxide (SO _x) combustion	In-furnace desulfurization not possible	High rate of in-furnace desulfurization
Low NO _x combustion	Difficult	Inherently low NO _x
Appropriate facility size	Small	Medium to large

Equipment and Installed Costs

A biomass boiler system is a complex installation with many interrelated subsystems. An integrated steam system will include the fuel prep-yard and handling equipment, the boiler itself, induced and forced air fans, controls, and water treatment systems. Varying levels of emission control equipment will normally be needed as well. Most installations will include cyclone separators to capture large fly ash, a baghouse for fine particulate matter (PM), and a dry scrubber system. NO_x emissions control in stoker boilers is provided by a selective non-catalytic reduction system using urea or ammonia that is installed in the top of the boiler. Other control equipment includes acid gas removal system, stack, ash handling, and continuous emissions monitoring equipment if required.

Table 5-4 provides total capital cost estimates (equipment and installation) for both stoker and circulating fluidized bed steam systems for three biomass fuel feed rates: 100 tons/day, 600 tons/day and 900 tons/day. These feed rates are comparable to steam systems producing 20,000; 150,000 to 185,000; and 250,000 to 275,000 lb/hr of steam, respectively, depending on steam temperature and pressure. Installed costs can vary significantly depending on the scope of the equipment included, output steam conditions, geographical area, competitive market conditions, site requirements, emission control requirements, and prevailing labor rates. The estimates presented in the table are budgetary estimates based on published data and discussions with equipment suppliers and developers. The estimates are

⁵⁵ Energy Product of Idaho, n.d.

based on steam conditions that might be typical for a process heating-only application in the small 100 tons/day biomass unit (250 pounds per square inch gauge [psig] saturated steam), and higher steam pressures (750 psig) for a steam turbine CHP configuration in the larger units. The range of expected cost variations can be as high as +/- 35 percent depending on the site and system variables listed above. Steam conditions also have a significant impact on boiler cost; higher temperatures and pressures require thicker tubes and more expensive materials (see Table 5-5).

Table 5-4. Estimated Installed Capital Costs for a Biomass-Fueled Steam Plant

Characteristics	Biomass Fuel Feed (tons/day)		
	100	600	900
Biomass heat input (MMBtu/hr)	35.4	297.5	446.3
Steam pressure (psig)	275	750	750
Stoker Boiler Integrated Steam Plant			
Steam output (lb/hr)	20,000	165,000	250,000
Stoker boiler equipment cost	\$1,195,000	\$7,980,000	\$10,790,000
Other equipment and installation	\$795,000	\$10,020,000	\$12,460,000
Total Installed Boiler System Cost	\$1,990,000	\$18,000,000	\$23,250,000
Total Installed Biomass Prep-Yard*	\$2,640,000	\$5,430,000	\$7,110,000
Total Installed Steam Plant Cost	\$4,630,000	\$23,430,000	\$30,360,000
Unit Cost (\$/lb steam)	\$232	\$142	\$121
Fluidized Bed Integrated Steam Plant			
Steam output (lb/hr)	20,000	175,000	260,000
Fluidized bed boiler equipment cost	\$6,175,000	\$14,490,000	\$19,790,000
Other equipment and installation	\$795,000	\$10,020,000	\$12,460,000
Total Installed Boiler System Cost	\$6,970,000	\$24,510,000	\$32,250,000
Total Installed Biomass Prep-Yard*	\$2,640,000	\$5,430,000	\$7,110,000
Total Installed Steam Plant Cost	\$9,610,000	\$29,940,000	\$39,360,000
Unit Cost (\$/lb steam)	\$480	\$171	\$151

*Prep-Yard costs are estimated based on the capital cost curve developed in section 4.1.5

Source: Based on data from Antares Group, Inc., 2003; discussion with equipment suppliers and developers.

As shown in Table 5-4, the prep-yard and fuel handling system represents a significant portion of the total steam system costs, ranging from 15 to 25 percent of the total steam system costs for the larger sized units and 25 to 50 percent of the total cost of the 100 tons/day steam system. Fluidized bed boiler equipment costs are higher than the simpler stoker technology; the fluidized bed boiler itself is more than three times as expensive as a stoker boiler in the smallest size shown; in the larger sizes, the fluidized bed boiler is 35 to 40 percent more expensive. The unit capital costs (\$/lb steam) for a biomass-fueled steam plant, including the prep-yard costs, are 20 to 25 percent more expensive for the larger fluidized bed systems. A portion of the higher capital cost is offset by the higher output due to higher efficiency.

The cost of the boiler is also a function of the steam output conditions as shown in Table 5-5. Generating higher pressure and temperature steam requires special and more expensive alloys and thicker water tubes. Boilers producing very high pressure steam can be more than twice as expensive as boilers generating low pressure steam.

Table 5-5. Effect of Steam Output Conditions on Boiler Capital Costs

Steam Conditions	Boiler Cost Factor
150–250 psig	1.0
600–750 psig	1.15–1.25
1,250–1,500 psig	1.5–2.0

Source: Matches, 2003.

O&M Costs

Estimated non-fuel O&M costs for stoker and fluidized bed boiler systems are provided in Table 5-6 for the three steam system sizes, based on published data and discussion with manufacturers. The O&M costs are evaluated within the context of an integrated plant. Total O&M costs include the labor for the prep-yard, and labor, materials, and parts for the boiler system itself. Boiler system O&M estimates were based on an annual non-labor component for spare parts and maintenance equipment assumed to be 2 percent of boiler capital costs. Variable costs for chemicals, water, and electricity needed to run blowers and auxiliary equipment were assumed to be approximately \$0.20 to \$0.25 per thousand pounds of steam output.

Table 5-6. Annual O&M Costs for a Biomass-Fueled Steam Plant

Characteristics	Biomass Fuel Feed (tons/day)		
	100	600	900
Stoker Boiler Integrated Steam Plant			
Steam output (lb/hr)	20,000	165,000	250,000
Prep-yard labor	\$400,000	\$320,000	\$320,000
Boiler section O&M	\$160,000	\$1,095,000	\$1,110,000
Total Annual O&M	\$560,000	\$1,415,000	\$1,430,000
Total Annual O&M (\$/1,000 lb Steam)*	\$3.55	\$1.09	\$0.73
Fluidized Bed Integrated Steam Plant			
Steam output (lb/hr)	20,000	175,000	260,000
Prep-yard labor	\$400,000	\$320,000	\$320,000
Boiler section O&M	\$260,000	\$1,190,000	\$1,205,000
Total Annual O&M	\$660,000	\$1,510,000	\$1,525,000
Total Annual O&M, (\$/1,000 lb Steam)*	\$4.19	\$1.09	\$0.74

*Based on 90 to 95 percent steam system capacity factor.

Source: Based on data from Antares Group, Inc., 2003; discussions with developers.

As shown in Table 5-6, the two boiler types are assumed to have the identical prep-yard labor requirement for the same output. The 100 tons/day plant uses a less automated system, so the labor requirement is higher than for the larger plants using an automated prep-yard. On a unit cost basis, O&M costs are higher for the fluidized bed boiler in the 100 tons/day size, but equal to the stoker boiler O&M costs for the two larger sizes.

Commercialization Status

Stoker boilers have long been a standard technology for biomass as well as coal, and are offered

by a number of manufacturers. Fluidized bed boilers are a more recent technology, but are also commercially available through a number of manufacturers. Until recently, however, fluidized bed boiler use has been more widespread in Europe than the United States, and many of the suppliers are European-based.

As shown in Table 5-6, when evaluated within the context of an integrated plant on a unit cost basis, O&M costs are higher for a smaller circulating fluidized bed processing 100 tons/day, but lower than the stoker boiler for the two larger sizes evaluated in this study.

Overall Cost and Performance Characteristics

A summary of the cost and performance of typical biomass steam systems is shown in Table 5-7.

Table 5-7. Summary of Biomass Combustion Boiler System Cost and Performance

System	Biomass Fuel Feed (tons/day)		
	100	600	900
Biomass Fuel Characteristics			
Energy content (dry) (Btu/lb)	8,500	8,500	8,500
Moisture content (%)	50	30	30
Energy content (as received) (Btu/lb)	4,250	5,950	5,950
Stoker Boiler Integrated Steam Plant			
Steam output (lb/hr)	20,000	165,000	250,000
Boiler efficiency (zero moisture) (%)	77	77	77
Boiler efficiency (moisture adjusted) (%)	63	71	71
Heat input to boiler (MMBtu/hr)	35.4	297.5	446.3
Heat input to steam (MMBtu/hr)	22.5	212.0	318.0
Capacity factor (%)	95	95	95
Cost Factors			
Total installed boiler costs	\$1,990,000	\$18,000,000	\$23,250,000
Total installed steam system costs	\$4,630,000	\$23,430,000	\$30,360,000
Unit capital cost (\$/lb steam)	\$232	\$142	\$121
Non-fuel O&M cost (\$/1,000 lb steam)	\$3.55	\$1.09	\$0.73
Fluidized Bed Integrated Steam Plant			
Steam output (lb/hr)	20,000	175,000	260,000
Boiler efficiency (zero moisture) (%)	80	80	80
Boiler efficiency (moisture adjusted) (%)	67	75	75
Heat input to boiler (MMBtu/hr)	35.4	297.5	446.3
Heat input to steam (MMBtu/hr)	23.6	221.7	332.5
Capacity factor (%)	95	95	95
Cost Factors			
Total installed boiler costs	\$6,970,000	\$24,510,000	\$32,250,000
Total installed steam system costs	\$9,610,000	\$29,940,000	\$39,360,000
Unit capital cost (\$/lb steam)	\$480	\$171	\$151
Non-fuel O&M cost (\$/1,000 lb steam)	\$4.19	\$1.09	\$0.74

Source: NREL, 2003.

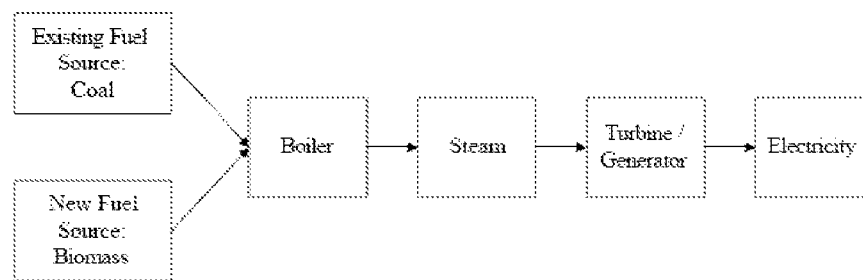
5.1.2 Cofiring

One of the most cost effective and easily implemented biomass energy technologies is cofiring with coal in existing coal-fired boilers. Cofiring refers to the practice of mixing biomass with a fossil fuel in high-efficiency boilers as a supplementary energy source. In biomass cofiring, biomass can substitute for up to 20 percent of the coal used in the boiler. Cofiring is typically used when either the supply of biomass is intermittent or when the moisture content of the biomass is high. At large plants, biomass is cofired with coal, and more coal is typically used than biomass. At small plants, biomass is cofired with natural gas, and more biomass is typically used than natural gas because the natural gas is used to stabilize combustion when biomass with high-moisture content is fed into the boiler.

Characterization

Figure 5-5 shows a process diagram for a standard coal-based cofiring plant. Biomass has been cofired with coal economically in commercial plants, which is principally viewed as a fuel cost reduction strategy. In certain situations, cofiring has provided opportunities for utilities to get fuel from wood manufacturing and other businesses at zero or negative cost. Overall production cost savings can also be achieved by replacing coal with inexpensive biomass fuel sources such as wood waste and waste paper. Typically, biomass fuel supplies should cost at least 20 percent less, on a thermal basis, than coal supplies before a cofiring project can be economically attractive.

Figure 5-5. Biomass Cofiring in Coal Power Plant



Source: Antares Group, Inc., 2003.

Biomass cofiring is mainly a retrofit application. A basic principle of cofiring is that significant changes to the boiler are not required beyond some minor burner modifications or additions necessary to introduce and burn the supplemental fuel. To meet this objective, cofiring biomass fuels is usually done on a limited basis, with the amount of biomass ranging from 5 to 15 percent of the total heat input to the boiler.⁵⁶ Biomass fuels that have been successfully cofired include wood and pelletized waste paper. Interest is growing in cofiring biomass among electric utilities and other users of coal boilers, chiefly due to the need to improve air emissions from coal-burning facilities, as well as to diversify fuel supplies.

Table 5-8 gives a sense of the size of typical utility cofiring power plants, the percentage of biomass fuel used (generally about 10 percent, but up to 50 percent), and the types of biomass feedstock used (wood, wood waste, wood residues, and sawdust).

⁵⁶ Fehrs and Donovan, 1999.

Table 5-8. Utility Cofiring Biomass With Coal (Continuous Operation)

Plant Name	Location	Biomass Feedstock	Total Plant (MW)	Biomass (MW)	Boiler Type
6th Street—Alliant Energy	Cedar Rapids, IA	Agricultural and wood waste	85	6.5	Fluidized bed
Bay Front—Northern States	Ashland, WI	Wood residues	34	5.0	Stoker
Colbert—Tennessee Valley Authority	Tuscumbia, AL	Wood residues	190	3.0	Pulverized coal
Greenridge—AES Corporation	Dresden, NY	Wood residues	108	10.0	Pulverized coal
King—Northern States Power	Bayport, MN	Sawdust	560	10.0	Cyclone
Tacoma Steam Plant #2	Tacoma, WA	Wood	25	12.5	Fluidized bed
Willow Island—Allegheny Energy	Pleasants, WV	Sawdust, tire-derived fuel	188	2.3	Cyclone
Yates—Southern Co./Georgia Power	Newnan, GA	Wood residues	150	2.0	Pulverized coal

Source: Antares Group, 2003

Efficiency

Usually, no major changes in boiler efficiency result from cofiring. However, some design and operational changes might be needed to maximize boiler efficiency while maintaining acceptable opacity, baghouse performance, and other operating requirements. Without these adjustments, boiler efficiency and performance can decrease. For example, at a biomass heat input level of 10 percent, boiler efficiency losses of 2 percent were measured during cofiring tests at a facility with a pulverized coal boiler when no adjustments were made.⁵⁷ Numerous cofiring projects have demonstrated that efficiency and performance losses can be minimized with proper awareness of operational issues.

Operating Availability

The availability of biomass and coal cofired boilers is similar to that of regular coal boilers, if proper modifications are made to the system. If some of the potential operating issues mentioned in the next section manifest, then availability might be negatively affected.

Operating Advantages and Disadvantages

Typically, cofiring biomass in an existing coal boiler requires modifications or additions to fuel handling, processing, storage, and feed systems. Slight modifications to existing operational procedures, such as increasing overfire air, might also be necessary, as well as increasing fuel feeder rates to compensate for the lower density and heating value of biomass.

As covered in Chapter 4, fuel characteristics and processing can greatly affect the ability to use biomass as a fuel in boilers. Wood chips are preferable to mulch-like material for cofiring with coal in stoker boilers because the chips are similar to stoker coal in terms of size and flow characteristics. This

⁵⁷ Tillman, 2000.

similarity minimizes problems with existing coal handling systems. When using a mulch-like material or a biomass supply with a high fraction of fine particles (sawdust size or smaller), periodic blockage of fuel flow openings in various areas of the conveying, storage, and feed systems can occur. These blockages can cause significant maintenance increases and operational problems; therefore, fuel should be processed to avoid difficulties with existing fuel feeding systems.

Another fuel consideration when dealing with biomass is the potential for problems with slagging, fouling, and corrosion. Some biomass fuels have high alkali (principally potassium) or chlorine content that can lead to unmanageable ash deposition problems on heat exchange and ash-handling surfaces. Chlorine in combustion gases, particularly at high temperatures, can cause accelerated corrosion of combustion system and flue gas cleanup components. These problems can be minimized or avoided by screening fuel supplies for materials high in chlorine and alkalis, limiting the biomass contribution to boiler heat input to 15 percent or less, using fuel additives, or increasing soot-blowing. The most troublesome biomass resource tends to be agricultural residues, including grasses and straws, which have high alkali and chlorine contents. In contrast, most woody materials and waste papers are relatively low in alkali and chlorine and should not present this problem.

Currently, about 25 percent of the fly ash from coal-fired power plants is used as a feedstock for cement and concrete production, while another 15 percent is used as a feedstock in other applications.⁵⁸ According to current industry standards,⁵⁹ only fly ash from coal combustion qualifies for use in cement/concrete applications. Cofiring biomass in a coal power plant would keep the fly ash from meeting the current standard. Similarly, coal fly ash will sometimes not meet the current standard when certain emissions control techniques are used, such as ammonia injection. Though these restrictions can impact the economics of biomass cofiring, the value of finding a productive use for fly ash and other coal combustion products is primarily the avoidance of a roughly \$20/ton landfill fee. For coal with 10 percent ash content, this value would be worth about \$2/ton of the input fuel cost. While the current restrictions are a barrier to considering cofiring in some applications, other uses of fly ash are not affected, and researchers are currently studying the impact of using fly ash from biomass and biomass/coal cofiring on concrete characteristics. Early results show that biomass and cofired fuels do not adversely affect the usefulness of fly ash in cement and concrete, and in fact might have some advantages.⁶⁰ It is likely that this work will eventually lead to a reevaluation of the standard and inclusion of fly ash from cofiring as an acceptable cement/concrete feedstock as has already happened in Europe.⁶¹

Equipment and Installed Costs

Cofiring typically does not involve added investment for the boiler equipment that is already in place for the coal-fired plant. There are additional costs for new fuel handling and processing equipment, boiler modifications, controls, engineering fees, and contingency. For blended fuel input systems, in which the biomass is added upstream of the coal fuel preparation equipment, the costs for the added feed preparation are on the order of 15 to 30 percent of the costs shown in the previous section in Table 5.4 for a dedicated biomass system. For systems using a separate fuel feed system, the costs are comparable to the costs (\$/ton of biomass feed) for a dedicated biomass plant.

⁵⁸ American Coal Ash Association, n.d.

⁵⁹ ASTM C-618.

⁶⁰ Wang, 2007.

⁶¹ In 2004, European Standard EN 450 dealing with fly ash specifications for use in concrete was approved for modification to include fly ash from a wide range of cofired biomass and waste feedstocks. These changes are in the process of being adopted by the European Union member countries.

O&M Issues

As discussed under capital costs, additional O&M to the boiler section attributable to the addition of biomass for cofiring is minimal. Maintenance requirements for boilers cofiring biomass and coal are similar to those for coal-only boilers. However, slight changes to previous operational procedures, such as increasing overfire air and fuel feeder speeds, might be needed. Increases in O&M costs for biomass cofiring with coal are almost entirely for the biomass receiving and feed preparation. For a blended system, the adjustments to feed preparation O&M are also on the order of 15 to 30 percent of the cost of a dedicated biomass plant.

Commercialization Status

Organizations such as electric utilities, DOE, and the Electric Power Research Institute (EPRI), have conducted research and field tests on biomass cofiring in small- and large-scale utility boilers for a number of years. These tests have shown that cofiring with biomass has been successfully accomplished in a wide range of boiler types, including cyclone, stoker, pulverized coal, and bubbling and circulating fluidized bed boilers. According to the Federal Energy Management Program, at least 182 separate boilers and organizations in the United States have cofired biomass with fossil fuels although this number is not comprehensive. Of the 182 cofiring operations, 114 (or 63 percent) have been at industrial facilities, 32 at utility-owned power plants, 18 at municipal boilers, 10 at educational institutions, and eight at federal facilities⁶².

5.2 Gasification Technologies

Biomass gasification for power production involves heating solid biomass in an oxygen-starved environment to produce a low or medium calorific gas. Depending on the carbon and hydrogen content of the biomass and the gasifier's properties, the heating value of the syngas, can range anywhere from 100 to 500 Btu/cubic foot (10 to 50 percent that of natural gas). The heating value of syngas generally comes from CO and hydrogen produced by the gasification process. The remaining constituents are primarily CO₂ and other incombustible gases. Biomass gasification offers certain advantages over directly burning the biomass because the gas can be cleaned and filtered to remove problem chemical compounds before it is burned. Gasification can also be accomplished using chemicals or biologic action (e.g., anaerobic digestion); however, thermal gasification is currently the only commercial or near commercial option.

The fuel output from the gasification process is generally called *syngas*, though in common usage it might be called *wood gas*, *producer gas*, or *biogas*. Syngas can be produced through direct heating in an oxygen-starved environment, partial oxidation, or indirect heating in the absence of oxygen. Most gasification processes include several steps. The primary conversion process, called pyrolysis, is the thermal decomposition of solid biomass (in an oxygen-starved environment) to produce gases, liquids (tar), and char. Pyrolysis releases the volatile components of the biomass feed at around 1,100° F through a series of complex reactions. Biomass fuels are an ideal choice for pyrolysis because they have so many volatile components (70 to 85 percent on dry basis, compared to 30 percent for coal). The next step involves a further gasification process that converts the leftover tars and char into CO using steam and/or partial combustion. In coal gasification, pure oxygen or oxygen-enriched air is preferred as the oxidant because the resulting syngas produced has a higher heating value, and the process is more efficient. In biomass gasification, oxygen is generally not used because biomass ash has a lower melting point than coal ash, and because the scale of the plants is generally smaller.

⁶² DOE, 2004.

Very high temperature processes involving passing the biomass through a plasma arc have been developed and tested primarily for waste remediation, contaminated wastes, and MSW. Plasma processes are not discussed in this report.

Compared with direct-fired biomass systems, gasification is not yet an established commercial technology. There is great interest, however, in the development and demonstration of biomass gasification for a number of reasons:

A gaseous fuel is more versatile than a solid fuel. It can be used in boilers, process heaters, turbines, engines and fuel cells, distributed in pipelines, and blended with natural gas or other gaseous fuels.

Gasification can remove fuel contaminants and reduce emissions compared to direct-fired systems.

Gasification can be designed to handle a wide range of biomass feedstocks, from woody residues to agricultural residues to dedicated crops, without major changes in the basic process.

Gasification can be used to process waste fuels, providing safe removal of biohazards and entrainment of heavy metals in non-reactive slag.

A gaseous fuel can be used in a high-efficiency power generation system, such as a gas turbine-combined cycle or fuel cells, provided it is cleaned of contaminants. When equipment is added to recover the heat from the turbine exhaust, system efficiencies can increase to 80 percent.

Like the direct combustion processes described in the previous section, two principal types of gasifiers have emerged: fixed bed and fluidized bed. Fixed bed gasifiers are typically simpler, less expensive, and produce a lower heat content syngas. Fluidized bed gasifiers are more complicated, more expensive, and produce a syngas with a higher heating value.

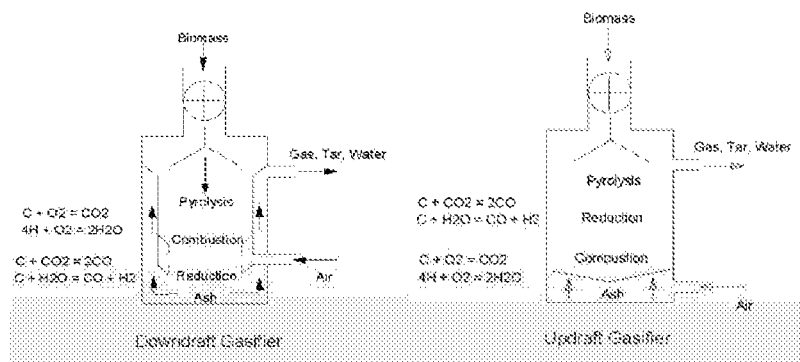
5.2.1 Gasifiers

Characterization

Fixed Bed Gasifiers

Fixed bed gasifiers typically have a fixed grate inside a refractory-lined shaft. The fresh biomass fuel is typically placed on top of the pile of fuel, char, and ash inside the gasifier. A further distinction is based on the direction of air (or oxygen) flow: downdraft (air flows down through the bed and leaves as biogas under the grate), updraft (air flows up through the grate and biogas is collected above the bed), or crossflow (air flows across the bed, exiting as biogas). Schematics of the primary section of the fixed bed gasifier types are shown in Figure 5-6.

Figure 5-6. Fixed Bed Gasifier Types



Source: Bain, 2006.

Table 5-9 compares fixed bed gasifier types. **Table 5-10** provides typical physical characteristics of a fixed bed gasifier. Fixed bed gasifiers are usually limited in capacity, typically used for generation systems that are able to produce less than 5 MW. The physics of the refractory-lined shaft reactor vessel limits the diameter and thus the throughput. Developers have identified a good match between fixed bed gasifiers and small-scale distributed power generation equipment. However, the variable economics of biomass collection and feeding, coupled with the gasifier's low efficiency, make the economic viability of the technology particularly site-specific.

Table 5-9. Comparison of Fixed Bed Gasification Technologies

	Type of Gasifier		
	Downdraft	Updraft	Crossflow
Operation	Biomass is introduced from the top and moves downward. Oxidizer (air) is introduced at the top and flows downward. Syngas is extracted at the bottom at grate level.	Biomass is introduced from the top and moves downward. Oxidizer is introduced at the bottom and flows upward. Some drying occurs. Syngas is extracted at the top.	Biomass is introduced from the top and moves downward. Oxidizer is introduced at the bottom and flows across the bed. Syngas is extracted opposite the air nozzle at the grate.
Advantages	Tars and particulate in the syngas are lower, allowing direct use in some engines without cleanup. The grate is not exposed to high temperatures.	Can handle higher-moisture biomass. Higher temperatures can destroy some toxins and slag minerals and metal. Higher tar content adds to heating value.	Simplest of designs. Stronger circulation in the hot zone. Lower temperatures allow the use of less expensive construction materials.
Disadvantages	Biomass must be very dry (<20 percent moisture content). The syngas is hot and must be cooled if compression or extensive cleanup is required. About 4 to 7 percent of the carbon is unconverted and remains in the ash.	Higher tar content can foul engines or compressors. The grate is exposed to high temperatures and must be cooled or otherwise protected.	More complicated to operate. Reported issues with slagging. High levels of carbon (33%) in the ash.

Table 5-10. Typical Characteristics of a Fixed Bed Gasifier

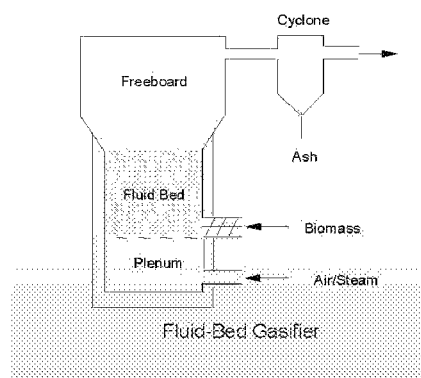
Parameter	Fixed Bed, Downdraft
Fuel size (inches)	0.4-4
Fuel ash content (% weight)	<6
Operating temperature (°F)	1450-2550
Control	Simple
Turn-down ratio	4:1
Construction material	Mild steel + refractory
Capacity (MW _{thermal}) (tons biomass/day)	<5 (<30)
Start-up time	Minutes
Operator attention	Low
Tar content (lb/MMBtu product gas)	<1.2
Heating value (Btu/scf) HHV	130

Source: GasNet, n.d.

Fluidized Bed Gasifiers

Fluidized bed gasifiers utilize the same gasification processes and offer higher performance than fixed bed systems, but with greater complexity and cost. Similar to fluidized bed boilers, the primary gasification process takes place in a bed of hot inert materials suspended by an upward motion of oxygen-deprived gas (Figure 5-7). As the amount of gas is augmented to achieve greater throughput, the bed will begin to levitate and become “fluidized.” Sand or alumina is often used to further improve the heat transfer. Notable benefits of fluidized bed devices are their high productivity (per area of bed) and flexibility. Fluidized bed gasifiers can also handle a wider range of biomass feedstocks with moisture contents up to 30 percent on average.

Figure 5-7. Fluidized Bed Gasifier



Source: Bain, 2006.

There are three stages of fluidization that can occur on the gasifier depending on the design: bubbling, recirculating, and entrained flow. At the lower end of fluidization, the bed expands and begins to act as a fluid. As the velocity is increased, the bed will begin to “bubble.” With a further increase in airflow, the bed material begins to lift off the bed. This material is typically separated in a cyclone and “recirculated” to the bed. With still higher velocities, the bed material is entrained (i.e., picked up and carried off in the airflow).

Fluidized bed gasifiers can be designed to use a portion of the pyrolysis gases to generate the heat to drive the process, or they can be externally fired. Operating the gasifier at higher pressures increases the throughput; however, this also increases the gasifier’s complexity and cost. In these units, the biomass is fully converted after going through the pyrolysis and char conversion processes.

By reducing the quantity of air and process temperature, it is possible to operate fluidized bed boilers as gasifiers. In this operating mode, the gasifiers produce a gas with a heating value of slightly more than 100 Btu/cubic foot (ft³). This gas is burned above the bed as additional air supply is injected upstream of the boiler tube section.

Table 5-11 provides typical physical characteristics of a fluidized bed gasifier. A number of advanced-concept fluidized bed gasifiers aiming to produce a syngas with a heating value between 250 and 400 Btu/ft³ are under development. This type of syngas would be more appropriate for use in gas

turbines, fuel cells, and reciprocating internal combustion engines; however, these advanced concept gasifiers have not reached the point where they are proven in commercial operation.

Table 5-11. Typical Characteristics of a Fluidized Bed Gasifier

Parameter	Fluidized Bed
Fuel size (inches)	0-0.8
Fuel ash content (% weight)	<25
Operating temperature (°F)	1,350-1,750
Control	Average
Turn-down ratio	3
Construction material	Heat-resistant steel
Capacity (MW _{thermal}) (biomass tons/day)	5 and up (> 30)
Start-up time	Hours
Operator attention	Average
Tar content (lb/MMBtu product gas)	<2
Heating value (Btu/scf) HHV	150

Source: GasNet, n.d.

Efficiency

Both fixed and fluidized bed biomass gasification uses similar types of equipment as direct combustion. The biomass fuel is fed into a combustion/reaction vessel with either a fixed, fluidized, or moving bed. The thermodynamics of heat loss are similar, but gasification conditions are different from direct combustion. In direct combustion, 10 to 14 times the weight of the fuel is introduced as air. In gasification, the air entering the reactor, if any, is only one to two times the weight of the fuel. This difference reduces heat losses from the reaction zone. On the other hand, the syngas exits the gasification reactor at very high temperatures (1,200 to 1,500° F); some of this heat loss can be recovered either directly through the use of heat exchangers in the gas cooling section, or indirectly through the use of heat recovery from the combustion of the syngas in the power generation section. To the extent that heat is used to preheat incoming air, introduce high-temperature steam, or dry the incoming biomass, the efficiency of biomass to syngas conversion will be increased. Heat that is recovered from the hot gas cooling section can also be added to the CHP heat recovery. In this case, the intermediate efficiency value of syngas conversion is not increased but the overall CHP efficiency is. These differences combine to produce biomass to syngas efficiencies (heating value of the syngas divided by the heating value of the biomass) of 60 to 80 percent. In integrated configurations, however, additional steam can be generated from cooling the hot syngas exiting the reactor prior to cleanup.

Operating Availability

Due to the fact that commercialization of biomass gasification plants is in its early stages, no facility survey information was found on their availability or reliability. Plants are designed for continuous operation, and design performance is in the 90+ percent range. Actual experience with emerging technology tends to result in lower availability than is experienced during broad commercial use, as materials handling problems, control issues, and component failures cause more frequent unplanned outages than are seen after accumulating additional operating experience. With a newly established support infrastructure, outages also tend to last longer before being fixed or solved. A well

designed system, however, has a reasonable expectation of operating in the 85 to 95 percent availability range.

Operating Issues

As discussed above, moisture content, gas cleanup, and operating pressure can all affect operation of a gasifier. There are a number of operating issues common to the different types of gasification systems.

Moisture Content

Green biomass, defined as freshly harvested plant material, can contain a significant amount of water by weight (up to 60 percent). This water does not contribute to the heat content of the syngas while consuming a significant amount of energy in gasification. Even though water cannot be burned (oxidized) at elevated temperatures, it will dissociate into its elemental components—hydrogen and oxygen. The hydrogen will contribute to the calorific value of the syngas. This reaction is very temperature-sensitive, and the hydrogen and oxygen will usually recombine into water vapor as the syngas cools. Therefore, the moisture content of biomass must be strictly limited. If there is excess moisture, the gasification process cannot sustain itself without an external source of heat. As the moisture content of the biomass increases, the net energy available in the syngas decreases. Fixed bed gasifiers that use internal combustion of the syngas typically utilize biomass with less than 20 percent moisture content. Fluidized bed gasifiers typically require less than 30 percent moisture content.

Green biomass is the most readily available and inexpensive biomass product. The drying process requires a considerable additional capital investment and increases the O&M costs. Unfortunately, the cost of the drying equipment (equipment cost and O&M cost) seldom covers the cost savings of using green biomass.

Gas Cleanup

As syngas leaves the gasifier, it contains several types of contaminants that are harmful to downstream equipment, ash handling, and emissions. The degree of gas cleanup must be appropriately matched to its intended use. For use in reciprocating engines, gas turbines, and especially fuel cells, a very clean gas is required. As discussed in Table 5-12, the primary contaminants in syngas are tars, particles, alkali compounds, and ammonia. The types of contaminants that are observed depend on the biomass feedstock and the gasification process used.

Table 5-12. Gas Cleanup Issues

Contaminant	Description	Treatment
Tar	Tars (creosote) are complex hydrocarbons that persist as condensable vapors.	Wet scrubbers, electrostatic precipitators, barrier filters, catalysts, or combustion.
Particles	Particles are very small, solid materials that typically include ash and unconverted biomass.	Cyclone separators, fabric filters, electrostatic precipitators, and wet scrubbers.
Alkali compounds	Potassium, alkali salts, and condensed alkali vapors are part of the chemical composition of biomass.	First, cool syngas below 1,200° F, causing the alkali vapors to condense. Second, use cyclone separators, fine fabric filters, electrostatic precipitators, and wet scrubbers.
Ammonia	Ammonia is formed from nitrogen (fuel-bound and in air) and hydrogen (in fuel and in moisture content). When syngas is burned, ammonia is converted to NO _x .	Catalysts, hydrocarbon reforming, or wet scrubbing.

Because gasification occurs at an elevated temperature, syngas can have as much as a third of its total energy in sensible heat. Cleaning the gas while it is hot would be advantageous from an energy use perspective, but this task is currently difficult to accomplish. Research is ongoing regarding hot gas filters, which can be applied in coal gasification, as well as other high-temperature processes. Wet scrubbers are currently one of the most reliable and least expensive options for gas cleanup, even though they sacrifice a large portion of the sensible heat of the syngas. Cooling the hot syngas can provide a source of steam for the cleaning process, power generation, or end-use.

Operating Pressure

Gasifiers can be operated at either atmospheric or elevated pressures. Air-blown, atmospheric gasifiers produce a very low Btu gas 110 to 170 Btu/scf. To introduce this gas into a gas turbine in the power generation section of the plant requires considerable compression energy, up to a third of the turbine's output. Therefore, it would be advantageous to produce the syngas at a high pressure so that it can be introduced directly into the combustion section of a gas turbine without additional compression. Pressurized reactors, however, do need to compress any combustion air or oxygen that is introduced into the reactor and maintain a pressure seal on the biomass input and ash removal systems.

Advantages and Disadvantages

Fixed bed and fluidized bed gasifiers have specific operating advantages and disadvantages with biomass fuels depending on the biomass characteristics and site requirements. Table 5-13 provides a qualitative comparison of gasifier characteristics and operating issues for fixed bed and fluidized bed systems.

Table 5-13. Relative Advantages/Disadvantages of Gasifier Types

Gasifier	Advantages	Disadvantages
Updraft fixed bed	Mature for heat Small-scale applications Can handle high moisture No carbon in ash	Feed size limits High tar yields Scale limitations Low Btu gas Slagging potential
Downdraft fixed bed	Small-scale applications Low particulates Low tar	Feed size limits Scale limitations Low Btu gas Moisture-sensitive
Bubbling fluid bed	Large-scale applications Feed characteristics Direct/indirect heating Can produce higher Btu gas	Medium tar yield Higher particle loading
Circulating fluid bed	Large-scale applications Feed characteristics Can produce higher Btu gas	Medium tar yield Higher particle loading
Entrained flow fluid bed	Can be scaled Potential for low tar Potential for low methane Can produce higher Btu gas	Large amount of carrier gas Higher particle loading Particle size limits

Equipment and Installed Costs

The main cost for the gasification train is the primary gasification reactor itself. Supplementary processing can occur in a tar cracker. Indirect gasifiers have separate char combustors to supply heat. The next major part is the gas cleanup section, which includes ash removal, quench, bag filter, wet scrubber, and heat exchangers to cool the syngas and provide heat to other parts of the process or to contribute to the CHP heat utilization. Capital costs for the gasification section and for a biomass-to-syngas plant are shown in Table 5-14. These costs are estimated based on published estimates (Antares Group, Inc., 2003) and discussions with equipment suppliers. The unit costs do not show a uniform declining trend as a function of size, but instead vary depending on the process considered.

Table 5-14. Biomass Gasification Capital Costs to Produce Syngas

	Gasifier Cases			
	Atmospheric Gasification	Atmospheric Gasification	Atmospheric Gasification	High-Pressure Gasifier
Gasifier type	Fixed	Fluidized	Fluidized	Fluidized/ high-pressure
Tons/day (as received)	100	260	450	1,200
Gasifier equipment	\$1,225,000	\$10,050,000	\$15,158,000	\$34,682,000
Installation	\$612,000	\$5,024,000	\$7,578,000	\$17,338,000
Total Installed Gasification	\$1,837,000	\$15,074,000	\$22,736,000	\$52,020,000
Biomass Prep Yard*	\$2,639,700	\$3,947,400	\$4,972,000	\$9,685,766
Total Installed Capital Cost	\$4,476,700	\$19,021,400	\$27,708,000	\$61,705,766
Unit Cost (\$/MMBtu/hr) (syngas)	\$127,164	\$209,425	\$174,130	\$161,270

*Prep-Yard costs are estimated based on the capital cost curve developed in section 4.1.5

Source: Based on data from Antares Group, Inc., 2003; discussion with equipment suppliers and developers.

O&M Costs

Non-fuel O&M costs for gasification include O&M labor, supervisory labor, water, ash removal, insurance, taxes, royalties, and other operating materials. These costs are estimated in Table 5-15 based on published estimates and discussions with equipment suppliers.⁶³

⁶³ Antares Group Inc., 2003

Table 5-15. Gasification O&M Cost Estimates for Syngas Production

	Gasifier Cases			
	Atmospheric Gasification	Atmospheric Gasification	Atmospheric Gasification	High-Pressure Gasifier
Gasifier type	Fixed	Fluidized	Fluidized	Fluidized/ high-pressure
Tons/day (as received)	100	260	450	1,200
Net capacity, MMBtu/hr	35.2	90.8	159.1	382.6
Pre-yard labor costs	\$400,000	\$320,000	\$320,000	\$400,000
Gasifier section O&M	\$502,000	\$634,500	\$789,500	\$2,235,800
Total Annual O&M (to syngas)	\$902,000	\$954,500	\$1,109,500	\$2,635,800
Gasification O&M (\$/MMBtu)	\$3.250	\$1.333	\$0.884	\$0.874

Source: Based on data from Antares Group, Inc., 2003; discussion with equipment suppliers and developers.

A summary of the cost and performance for the range of biomass gasification systems considered is provided in Table 5-16.

Table 5-16. Biomass Gasification Cost and Performance

	Gasification Technologies			
	Atmospheric Gasification	Atmospheric Gasification	Atmospheric Gasification	High-Pressure Gasifier
Gasifier type	Fixed	Fluidized	Fluidized	Fluidized/ high-pressure
Tons/day (as received)	100	260	450	1,200
Feedstock Characteristics				
Energy content dry (Btu/lb)	8,500	8,500	8,500	8,476
Moisture content (%)	30	30	30	38
Energy content as received (Btu/lb)	5,950	5,950	5,950	5,255
Biomass Conversion				
Gasifier efficiency (moisture adjusted)(%)	65	71	71	72
Biomass fuel value to gasifier (MMBtu/hr)	49.6	127.9	224.1	531.9
Fuel produced (MMBtu/hr)	32.2	90.8	159.1	382.6
Heating value (Btu/scf HHV)	110.0	110.0	110.0	128.8
Fuel pressure (psig)	Atmospheric	Atmospheric	Atmospheric	Pressurized
Plant capacity factor (%)	90	90	90	90
Capital Costs				
Gasifier equipment	\$1,225,000	\$10,050,000	\$15,158,000	\$34,682,000
Installation	\$612,000	\$5,024,000	\$7,578,000	\$17,338,000
Total Installed Gasification Section	\$1,837,000	\$15,074,000	\$22,736,000	\$52,020,000
Biomass Prep-Yard	\$2,639,700	\$3,947,400	\$4,972,000	\$9,685,766
Total Installed Capital Cost	\$4,476,700	\$19,021,400	\$27,708,000	\$61,705,766
Unit Cost (\$/MMBtu/hr) (syngas)	\$127,164	\$209,425	\$174,130	\$161,270

Source: Based on data from Antares Group, Inc., 2003; discussion with equipment suppliers and developers.

Commercial Status

The majority of commercial gasification projects use coal or petroleum coke as a feedstock. Biomass gasification technologies have been a subject of commercial interest for several decades. By the 1990s, CHP had been identified as a potential near-term technology. Research and development concentrated on integrated gasification combined cycle and gasification cofiring demonstrations, which led to a number of commercial-scale systems. In the United States, projects mostly processed hard-to-manage feedstocks like bagasse and alfalfa. Low-energy gasifiers are now commercially available, and dozens of small-scale facilities are in operation.

A review of gasifier manufacturers in Europe, the United States, and Canada⁶⁴ identified 50 manufacturers offering commercial gasification plants in which 75 percent of the designs were fixed bed downdraft type; 20 percent of the designs were fluidized bed systems. The actual number of biomass gasification systems in operation worldwide is unknown, but is estimated to be below 50 based on literature review and discussions with industry sources. There are only a handful of commercially operating biomass gasification systems in the United States at this time, and many of these are partially government-funded demonstration units. In comparison, there are currently more than 100 biomass-fueled fluidized bed boilers in operation around the world.

There is still a considerable amount of development activity underway to address existing technical and operational issues:

- **Gasification**—Some gasification technologies using biomass and black liquor have developed to the point of large-scale demonstration. However, gasifier systems have not reached widespread commercial availability for systems suitable for integration with hydrogen separation technologies for fuel cells or fuel synthesis. This is due in part to areas of fuel chemistry that are not established enough to support the commercial demonstration programs and facilitate the development and scale-up of advanced gasifiers and gas cleanup systems.
- **Syngas cleanup and conditioning**—The raw gases from biomass systems do not currently meet strict quality standards for downstream fuel, chemical synthesis catalysts, or those for some power technologies. These gases will require cleaning and conditioning to remove contaminants such as tar, particulates, alkali, ammonia, chlorine, and sulfur. Available cleanup technologies do not yet meet the needed cost, performance, or environmental criteria needed to achieve commercial implementation.
- **Sensors and controls**—Development of effective process controls is needed to maintain plant performance and emissions at target levels with varying load, fuel properties, and atmospheric conditions. New sensors and analytical instruments are under development to optimize control systems for thermochemical systems.
- **Process integration**—As with all new process technologies, demonstrating sustained integrated performance that meets technical, environmental, and safety requirements at sufficiently large scale is essential to supporting commercialization. Applications such as black liquor integration in paper mills has the added complexity of being attached to an existing commercial process where the unit operations associated with steam production, power, pulping, and chemical recovery must all be integrated.

⁶⁴ European Biomass Industry Association, n.d.

- **Containment (materials of construction)**—Experience with existing gasifiers indicates that gasification reactions are difficult to contain and that materials development for reactor shells and internals, refractory materials to line containment vessels, vessel design, and increased knowledge of bed behavior and agglomeration will improve performance over the long term.

5.3 Modular Systems

Modular biomass-fueled CHP systems are defined as small systems, less than 5 MW, though typically smaller, with the main operating components coming in one or more pre-engineered and packaged modules for simple installation at the user's site. The systems typically include a fuel processor (combustion or gasification), necessary intermediate fuel cleanup, an electric generator, and heat recovery from both the power generation and energy conversion sections. An automatic fuel storage and delivery system must be added for a complete operating system.

Small modular biomass systems can supply electricity to rural areas, farms, businesses, and remote villages. These systems use locally available biomass fuels such as wood, crop waste, animal manure, and LFG. Development of biomass-fueled modular power systems is of great interest internationally as a means to bring power to isolated communities in areas lacking power and fuel infrastructure. In the United States, there is interest in small systems to utilize opportunity fuels from a local area, such as crop wastes or fire control forest thinning.

A partial listing of specific developer/manufacture modular systems is provided in Appendix D.

Characterization

Modular systems are essentially scaled down versions of larger systems. There are systems that use direct-fired technology with steam power, and systems that use gasification technology and gaseous fuel burning power technologies (discussed in Chapter 6) such as internal combustion engines, microturbines, and Stirling engines. There are also direct fired systems that use Stirling engines for power production, as well as systems that employ gasification, wherein the hot raw gas is combusted to raise steam.

Modular Gasification Systems

Figure 5-8 shows a schematic of a 75-kW modular biomass gasification system that is representative of systems under development. The figure shows that there are eight submodules included in the basic system and that the storage and feed submodules are not included.

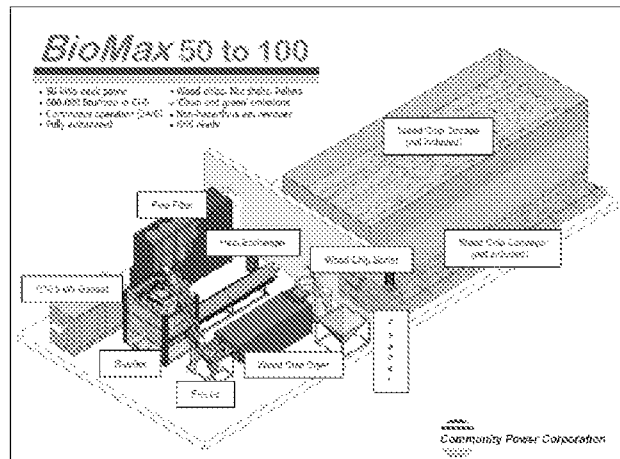
Basic Package Modules

1. Automatic biomass feed system.
2. Dryer to reduce the feedstock moisture content.
3. Chip sorter for sizing.
4. Heat exchanger that extracts heat from the gasifier for use in the dryer and for onsite thermal applications.
5. Gasifier feeder.

6. A downdraft gasifier producing low Btu gas (heating value of about 110 Btu/scf—HHV).
7. Filtering stages that remove particulates.
8. The power module—this can be an internal combustion engine designed to run on low Btu fuel, a microturbine, a Stirling engine, or even a fuel cell. The power module also has heat recovery equipment to provide additional useable thermal energy for onsite use. Because the gas is of such a low Btu content, propane or natural gas is required on system start-up. After start-up, the system can run on the syngas alone.

Systems such as these will require feedstock storage with an in-place delivery system. An in-ground storage bunker with a moving bed would allow direct delivery of fuel loads into the automated system. This can consist of a permanently installed live bottom van into which dump trucks can deliver a sized fuel supply.

Figure 5-8. Example Modular Biomass Gasification System



Source: Community Power Corporation, n.d.

Modular Combustion Systems⁶⁵

Direct combustion in fixed bed combustors is a commercial technology in larger sizes. In these larger systems, as characterized previously, power is generated by steam turbines. In modular systems, other power systems are being developed that are more suitable for small-sized applications. The typical power and heat cycles being employed or explored for use are as follows:

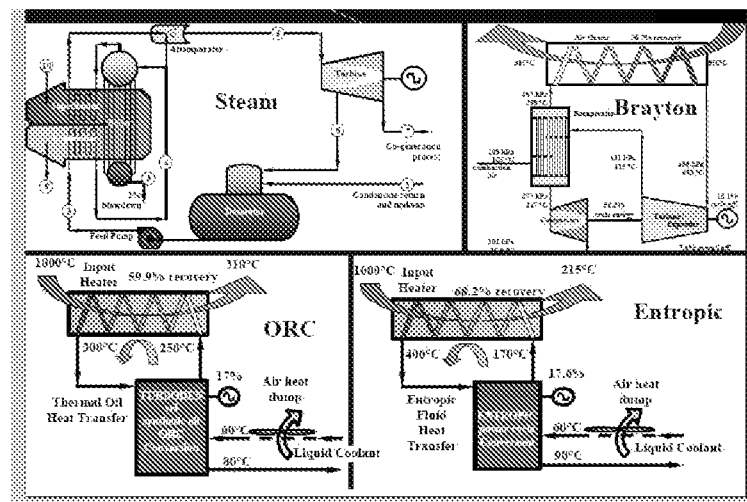
- Steam cycle
- Organic Rankine cycle (ORC)

⁶⁵ Example shown, BioMax, is developed by Community Power Corporation.

- Brayton cycle, hot air turbine
- Entropic cycle, as defined by its developer, similar to Organic Rankine cycle but with a higher temperature differential producing higher efficiencies
- Stirling Engine, external combustion

Modular power and heat cycles that can be driven by biomass combustion are shown in Figure 5-9.

Figure 5-9. Heat Engine Power Cycles for Modular Biomass Combustion Systems⁶⁶



Source: Smith, 2006.

In addition to the four power cycles shown, very small (500 watts to 10 kW) modular systems are being developed using Stirling engine technology. The generators will convert various biomass fuels (wood, wood pellets, sawdust, chips, or biomass waste) to electricity and useful heat.⁶⁷ These systems typically convert 10 to 20 percent of the fuel energy to electricity; 60 to 70 percent of fuel energy is then available for heating water and spaces. The burner for the prototype system includes a ceramic fire box and a fuel hopper with a fuel capacity of 24 hours. It accomplishes complete two-stage combustion with comparatively low emissions. The Stirling engine-alternator requires minimal maintenance because its gas bearings eliminate contact, friction, and wear. Its projected life is 40,000 hours.

Modular Hybrid Gasification/Combustion Systems

The modular hybrid gasification/combustion system operates functionally like a direct combustion system. Power is derived by a back-pressure steam turbine that also provides steam for onsite thermal energy requirements. The difference is that the combustion chamber is actually a gasification

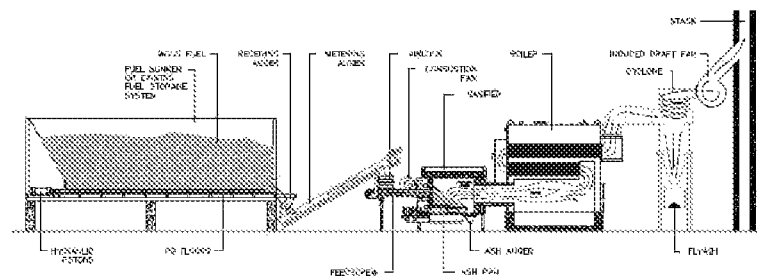
⁶⁶ Smith, 2006.

⁶⁷ A system under development by Sunpower Stirling engine technology licensee is External Power LLC of Indianapolis.

system that uses a two-chamber gasifier approach. The system is similar to a two-stage combustion boiler design. This approach allows the production of gas in a relatively cool chamber at temperatures from 1,000°F to 1,400°F, and then combustion in a relatively hot chamber—the boiler—at temperatures up to 2,300°F. These temperatures allow the complete removal of carbon from the fuel in the gasifier, and more complete oxidation of complex organics in the oxidation zone. The combination of these features results in a clean-burning, fuel-efficient system. CHP units include small back-pressure steam turbines from 100 kW up to several megawatts.

This approach combines the simplicity and low cost of a combustion system with the gasification advantages of more complete carbon conversion and cleaner combustion characteristics. An example of a modular gasification/combustion system is shown in Figure 5-10. This system has the capability to use fuels with moisture contents ranging from 6 to 55 percent (wet basis). The system also has a 20:1 turn-down ratio to allow it to idle during periods of low heat demand.

Figure 5-10. Example of Modular Gasification/Combustion Process



Source: Chiptec® Wood Energy Systems, n.d.⁶⁸

Efficiency

Modular system electric generation efficiencies are typically fairly low as shown in Table 5-17. In applications requiring considerable thermal energy, the overall CHP efficiencies are comparable to gas-fired systems. However, the electric to thermal ratio for these systems is much lower, so more of the total useful energy is delivered in the form of heat rather than in the form of higher value electricity.

⁶⁸ Example shown is a patented process by Chiptec® Wood Energy Systems, Burlington, Vermont.

Table 5-17. Efficiencies of Modular Biomass Systems, Based on Conversion of Switchgrass at 20 Percent Moisture

System Type	Electric Efficiency	Thermal Energy Delivered	Overall CHP Efficiency
Small steam	6%	59%	65%
Air Brayton	8%	41%	49%
Organic Rankine	11%	56%	67%
Entropic	13%	63%	76%
Stirling	13%	64%	77%
Modular gasifier	16–22%	29–53%	55–75%
Hybrid gasifier/combustor	<15%	45–55%	60–70%

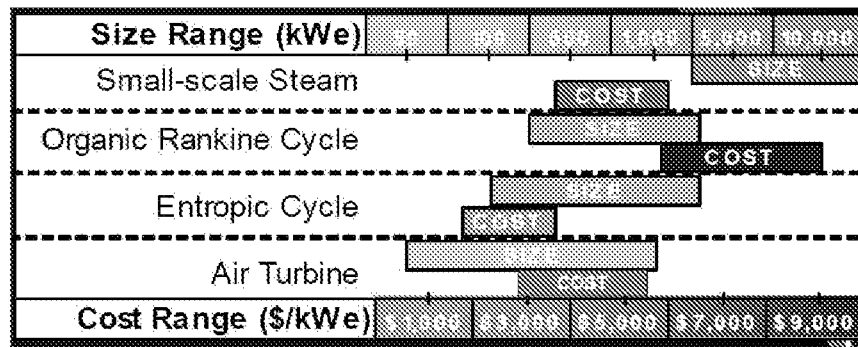
Operating Advantages and Disadvantages

The main operating advantages today are in the use of opportunity biomass fuels of low value such as wood chips or forest thinnings. In addition, many of the systems are targeted at remote applications where it would be too costly to connect to grid electricity.

The main disadvantage affecting all types of modular systems is the comparatively high capital costs associated with all of the required equipment. This equipment also takes up considerable space compared to conventional gas-fired CHP systems. The engine generator systems occupy only about 5 percent of the total space required for the modular biomass system. Another disadvantage is the need for maintenance and repairs associated with the many subsystems, particularly the solids handling components and filters.

Equipment and Installed Cost

Equipment costs are speculative. Information in this section is as provided by the vendors and secondary sources. Figure 5-11 shows a range of costs (\$/kW) for different types of direct-fired systems. It is not clear that these costs include the costs of feedstock storage and delivery, which would add another \$600 to 1,000/kW to the overall costs.

Figure 5-11. Size and Cost Ranges for Direct-Fired Modular Systems⁶⁹

Source: Smith, 2006.

Modular gasification costs are estimated to be between \$2,500 to \$4,000/kW for the basic equipment with another \$600 to \$1,000/kW for a biomass storage bunker and \$1,000 to \$2,000/kW for installation.

The hybrid gasification/combustion system by itself costs about \$300/kW. This component must be matched with feedstock storage and delivery (\$600 to \$1,000/kW), small-scale boiler, small-scale steam turbine generator (\$900 to \$1,200/kW), and other equipment, including controls, cyclone fly ash recovery system, and exhaust stack. Overall installed capital costs would be \$12,000 to \$18,000/kW.

O&M Costs

Most modular systems are characterized by continuous operation, automatic ash and char extraction, automatic feed, and automatic process control. Maintenance of 0.5 to 3 hours per week is required for monitoring feedstock deliveries, ash removal, filter cleaning or replacement, and inspecting and fixing problems with the automatic feed system. In addition, prime movers such as internal combustion engines or microturbines require similar maintenance attention as for gas-fired systems.

The overall costs and reliability of these systems has not yet been established.

Commercial Status

There are a number of small development companies working on modular biomass heat and power systems (listed in Appendix D). Most of the systems that have been installed in the United States are part of research, development, and demonstration projects funded by a variety of federal and state sources. DOE has an active research and development program on modular biomass as does USDA and the U.S. Forest Service. The United Nations also has an ongoing program in this area to develop village power systems using biomass.

⁶⁹ Smith, 2006.

Biomass Technology Review

October 21, 2010

Prepared for
Biomass Power Association

Prepared by
McHale & Associates, Inc.
70 Center Street
Portland, ME 04101



Executive Summary

This study was performed for the Biomass Power Association to review current technology that is available for high efficiency biomass power generation. The available technology is listed with a brief description of the technology.

The Massachusetts Department of Environmental Resources (DOER) has proposed new requirements for biomass Renewable Energy Credits (RECs). The minimum standard is a net plant efficiency of 40% to receive ½ credit and a net efficiency of 60% to receive a full credit¹. This study concludes that such efficiency standards are not achievable by a power generation unit currently in operation or by any new unit to be built any time in the foreseeable future.

Eleven existing plants were in the United States and Canada were reviewed. The average efficiency for a biomass power generation project is 23%. The heat rate for power generation at biomass leaders in the industry is between 11,700 Btu/kWh (29.2%) and 20,000 Btu/kWh (17.1%).

Regarding new facilities, the Report concludes that no new existing, financeable, commercially proven technology is available to meet the proposed efficiency standards.

The proposed efficiency standards can only be met by using cogeneration, or Combined Heat and Power (so-called "CHP"), which changes the economics of biomass energy from electricity-only to providing electricity as a by-product of thermal production. An existing facility that currently qualifies under the Massachusetts RPS program is not likely to draw a large industrial host to the facility and are unlikely to find financing even if such a host were found. . Even assuming that new biomass thermal applications could be economically justified given the price of competing fossil fuel sources, the distance from the fuel supply and the number of fuel deliveries to the plant each day makes such applications highly unlikely.

District energy applications are unlikely to be built under the proposed requirement.. The reason is that the heating load of a District Energy facility is not constant over the year. The heating load in the summer is zero; the average annual heat load is about 44% of the winter peak. Plants are likely to run only part of the year. For the periods that they do run and meet the efficiency requirements, the power generated is reduced to provide the thermal load, which results in reduced REC revenue that is insufficient to run the facility profitably.

The European biomass experience is not directly applicable to the New England market. Feed-in tariffs, a mature carbon market, long term stable market incentives, and a much higher power cost make CHP and district energy projects attractive. None of those factors exist in New England today.

Finally, it is important to note that the literature describing high efficiency power plants is misleading. It is important that common terms and definitions are used. The standard in the United States is to use Higher Heating Value (HHV) for solid fuel projects. In Europe, Lower Heating Value (LHV) is used for calculation of the fuel heating value and plant efficiency. Depending on the fuel, there is a 4%-7% difference in the result. So the reported 35% efficiency

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is 33% on a HHV basis. Additionally, the efficiency can be reported on a Gross output basis or a Net output basis. The Net output is the Gross less the plant auxiliary load. For a typical plant, the auxiliary load is 10% - 12% of the total generation. Assuming the reported 35% efficiency was based on gross output, LHV basis, the HHV, net efficiency would be less than 30%.

In summary, using a high efficiency standard for biomass power production is not reasonable, lacks economic viability, and assumes European--style markets and subsidies that are not found anywhere in the United States. The result of the proposed efficiency requirement will be to eliminate biomass as a ready, dispatchable, renewable energy power resource from the existing Massachusetts portfolio of renewable energy, and create a barrier for new biomass electricity anywhere in the Commonwealth or the Region.

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I. Introduction

This report examines the technologies and project economics for biomass power generation and cogeneration in the context of a proposed efficiency standard for the Commonwealth of Massachusetts. A background of the biomass market in the United States and specifically in New England is discussed. A review of current and emerging biomass technologies is discussed. Project economics are presented for existing technology to compare power generation and cogeneration schemes.

A. Definitions

The following definitions are used in this document:

AR – As Received
 BD – Bone Dry (0% Moisture)
 Btu – British Thermal Unit
 CHP - Combined Heat and Power. Used interchangeably with cogeneration
 CTG – Combustion Turbine Generator
 DE – District Energy
 REC – renewable Energy Credit
 STG – Steam turbine Generator
 Syngas – Synthesis gas
 LHV – Lower Heating Value, generally used for fuel heating value outside the US
 HHV – Higher Heating Value, generally used as the standard in the US
 MWh- Megawatt hours
 Q = Heat Transfer
 W = Work

Subscripts
 B = Boiler
 A = Ambient, used for thermal sink
 S = Stack
 U = Useful Heat

B. Background

(i) US Biomass Power Market

The growth of the renewable biomass power generation industry in the United States was a direct result of the passage and implementation of the Public Utility Regulatory Policies Act ² which opened up power generation to independent power producers. A combination of an interest in reducing US energy imports, increased imported fuel prices, and a ban on new natural gas generation along with the availability of long term power contracts led to the construction of many “merchant” (non utility owned) biomass power plants during the 1980's.

As the fuel for biomass plants was plentiful and obtained at a low cost in rural areas, small capacity electric generation plants were installed in many rural areas where a logging and wood

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processing economy existed. Although the fuel supply was plentiful, the Btu content was low and the fuel had a low density leading to the need to keep the plants relatively small to reduce trucking costs which generally limited a plant size to a 10 to 20 MW output that could be supported by harvesting operations in an approximate 60 to 75 mile radius. The economics of biomass power generation has never been such that trees are cut solely to supply these plants, as the cost to harvest the wood far exceeds the value of the fuel to the generator once transportation is included. The sale of wood biomass fuel is generally used as a means of partially subsidizing the economics of a logging operation that is producing higher grade wood for sawmill and wood pulp production. Large amounts of low grade wood fuel are also generated during forest management procedures.

In addition to the standalone biomass electric power generation plants, the regional pulp, paper and wood processing industry long present in the area installed biomass fired steam plants as fuel oil prices rose with some electric power generation capacity to primarily supply process steam and power for internal use for their processes. Also present at some pulp producing facilities are recovery "boilers" that burn a pulping byproduct, referred to as black liquor, as a means of chemical recovery and steam generation. Although black liquor is occasionally referred to as biomass fuel, the production of it is kept within one site and is part of the pulping cycle and therefore is not a viable biomass fuel with respect to regional electric power demand beyond load reduction at the facilities that generate it. These plants typically are not a major contributor of biomass generated power to the grid and will not be included in the discussion of the merchant fleet of biomass power plants in the region.

Subsequent to the installation of merchant biomass power plants in New England, continued deregulation and the discovery of additional natural gas deposits in North America led to a building boom of combined cycle natural gas power plants, which in turn led to an overall drop in energy prices below those that could be supported by the biomass industry. With a rise in the interest in the potential climate change impact of continued fossil fuel generation, the Commonwealth of Massachusetts established incentives to encourage generation of an ever increasing percentage of their electric power from renewable power sources leading to the Massachusetts Renewable Portfolio Standard (RPS). Given the lack of significant renewable power generation currently available in Massachusetts, a market has developed to supply the Commonwealth with renewably generated biomass power. Other New England states have also imposed RPS standards, each with differing interpretations and required percentages of renewable power. Despite the demand for renewable biomass power, there have been few merchant biomass power facilities constructed in the region since the 1980's due to lack of availability of long term contracts and low prices for natural gas. Recently, with the potential for long term incentives for renewable generation, merchant biomass power plants are again being proposed, although the Nation's inability to place a "price" on carbon that would differentiate biomass from fossil fuels is limiting the actual construction of plants. Figure 1 shows the current biomass power facilities located in the ISO New England market. Facilities that are REC qualified for the Commonwealth of Massachusetts are labeled.

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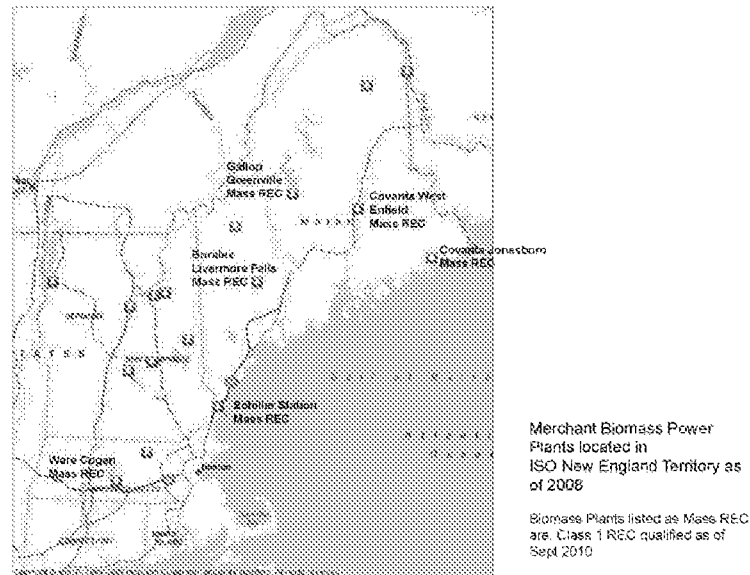


Figure 1

Merchant Biomass Power Plants in New England

The renewable power market is currently composed of two mature technologies and a host of small emergent technologies. The two mature technologies are hydroelectric and biomass power generation. Hydroelectric power generation in the New England market has plateaued and is shrinking as dams are removed for economic, fishery and recreational purposes. The emergent technologies, predominately consisting of wind and solar of various configurations, are slowly maturing although to date the technologies generally produce power on a non predictable basis that does not necessarily line up with the load demand of the region. As the majority of the electric power in the region is generated when needed with minimal storage capability, there is a demand for both primary types of electric power, base load and dispatchable. Baseload power is typically generated on a predictable 24 hour per day or planned basis reflecting average regional demand; dispatchable power is electric generation that can reliably be capable of being rapidly put into operation to supply transients in power demand. Hydroelectric can be baseloaded or dispatchable depending on the availability of upstream storage. Landfill gas is base load power. Biomass can vary its load profile somewhat

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to reflect system demand. The addition of emergent power generation adds a third component to the system which is intermittent. Although capable of generating power when appropriate resources, such as sun and wind are available, suitable dispatchable generation capacity or the capability to reduce the regional load must be available in case the resources are not available. Typically this dispatchable generation is higher cost fossil fueled generation with lower efficiency. The ratio of the rated output of power plant and the amount of power that can be expected to be generated on a long term basis is generally referred to as the availability of a plant. The mature renewable technologies typically have reliabilities in excess of 90% while the emergent technologies generally are regarded as less than 10%.

To date, both emergent technologies are dependent upon large subsidies of various types to be economically viable. Although off shore generated wind has the potential to have a higher availability, its current deployment and predicted cost makes it a possible future complement to the mature renewable technologies, but will not replace them unless there is a radical change in the New England Power Market and its ability to control load based on generation availability rather than customer demand.

Currently the region exhibits a long term electric load demand with two seasonal peaks, one seasonal peak roughly corresponding to the peak winter heating load and a second major yearly peak corresponding to the maximum summer cooling load.

(ii) The European Biomass Power Market

The current European biomass power market demand is a mix of demand for combined heat and thermal projects along with a growing demand for imported wood pellets to substitute a portion of fuel used in coal baseload power plants. Carbon reduction targets, high fossil fuel tariffs and an existing large coal based generation fleet have driven up the demand for renewably generated biomass power. Large existing district heating systems in many regions along with very generous subsidies for renewably generated power of any type, has led to the installation of biomass fired combined heat and power facilities optimized to tie into the district heating grids. Although district heating grids enable very high fuel utilization efficiency during times of adequate heating demand, the renewable electric power generation is a byproduct of the demand for heat. The relative scarcity of local wood fuel and high value for renewable fuel has led to a far reaching market of sourcing wood products from around the world. Given the economic and regulatory climate of shipping a low grade fuel long distances, the majority of the imported wood products are converted at the shippers site to wood pellets that allow the siting of biomass power plants in urban areas due to the far lower site footprint and local impact albeit at a far higher cost to the ultimate consumer.

(iii) Power Generation versus Combined Heat and Power Plants

The New England power grid is supplied by power generation-only biomass plants that are optimized to maximize electric power production. An alternative to power generation-only plants are Combined Heat and Power (CHP) plants, where the production of electrical energy is balanced with the production of useful thermal energy. When there is a steady demand for both

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thermal and electrical energy, a CHP plant can have higher overall fuel utilization than a comparable power- only plant. The vast majority of CHP plants are installed in industrial facilities that can generate electricity for less than the cost of purchasing utility power. The downside to a CHP plant is that the overall efficiency only remains high if there is use for the thermal power generated by the plant. Although there are several variations of CHP plants, the majority are set up to supply a thermal load to industrial facilities with electric power produced as a byproduct thus linking the power production to the thermal demand of the facility instead of to the regional power demand. Generally, the economics of the industrial sites is to remain a net user of power with sales of power to the grid only during unusual operational modes.

CHP plants are also occasionally installed where a small generation capability is installed on the outlet of the boiler to generate small volumes of power while dropping the steam pressure from a higher pressure to a lower pressure. This is common where there is a small demand for higher pressure steam and a much higher demand for lower pressure steam. In the past, there was also some value for onsite generation to allow the heating plant to remain operational when grid power was not available, but few small generators are equipped with the required equipment to perform this task.

Newer CHP systems are being installed where power is generated from a renewable feedstock and the resultant power is credited with Feed-in Tariffs that reward renewable power generation that offsets power previously supplied from the grid. Feed-in Tariffs are generally set at a high rate to encourage renewable generation. This method has been used quite successfully in Europe, although the overall costs have been quite high and most programs have reduced the tariffs recently to far lower levels in an attempt to reduce the subsidy cost. CHP units are primarily thermal units that have added equipment to generate power while supplying thermal demand rather than power plants intended to supply regional power demand. Therefore small CHP plants are not expected to contribute substantially to support the regional power demands that tend to occur independent of thermal load, leading to limited or no availability during spring summer or fall.

(iv) Conversion of existing Biomass Power Plants to CHP facilities

The conversion of a Biomass power plant to CHP purposes would be not be possible for the majority of the existing biomass power facilities in New England as there is no large year round thermal demand in close proximity to the plants. The plants, as currently configured, would require substantial alterations including replacement of the condensing steam turbine in order to export significant volumes of thermal energy to an adjacent host facility if one could be found.

III. Plant Efficiencies

There are numerous definitions for efficiency used for the description of conversion of energy. As each definition is targeted for a different audience, it is easy to confuse one definition of

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efficiency with another leading to comparisons of “apples to oranges”. The illustration below in Figure 2 illustrates a generic thermal cycle.

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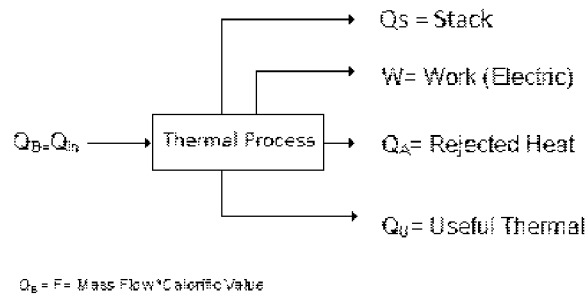


Figure 2

Generic Thermal Cycle

A. Efficiencies

The comparison of process and plant "efficiencies" is difficult as there are multiple definitions of efficiencies. In the US, the American Society of Mechanical Engineers publishes a series of Performance test codes that when properly executed can be used to define the efficiency of a given thermal process and establish the likely uncertainty in the results. Barring access to standardized testing and an agreed upon test methodology, efficiency comparisons are at best a broad approximation and at worse can be abused to make one type of power conversion process look better than another. Listed below are some of the more utilized efficiency definitions.

Heat Rate – This term is typically used in the electric power industry to describe the amount of energy input required to produce a given amount of electric power. The typical English units are Btu/kW. Note of all the efficiency definitions listed below, this definition has the useful work output as a denominator. All others use it as a numerator. Therefore as the heat rate reduces, the plant efficiency increases.

$$HR = Q_B / W$$

Efficiency – Useful Work out divided by Fuel in

$$\eta_{TH} = W / Q_B$$

Carnot Efficiency – The Carnot efficiency is the most efficient cycle to convert thermal energy unto work. This is a theoretical cycle that cannot be obtained in practice but is useful in determining an upper maximum power generation. It is important to note

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that the temperatures used in the equation are absolute temperatures, degrees Rankine in English units.

$$\eta_C = (T_B - T_A) / T_B = (Q_B - Q_A) / Q_B$$

Rational Efficiency— Is a ratio of actual work produced by a system to the system Exergy, which is the maximum useful work possible during a process that brings a system into equilibrium with a heat reservoir. The actual work is always going to be less than the exergy. This efficiency is useful for designing and optimizing processes.

$$\eta_R = W / \text{the change in thermodynamic potential of the system.}$$

Overall Efficiency – Is the work output of the system divided by the fuel input where the fuel input is calculated by the mass flow rate of the fuel multiplied by the calorific value of the fuel.

$$\eta_O = W / Q_{\text{Fuel}}$$

Where: Q_{Fuel} = Fuel mass flow rate X calorific value

Energy Utilization Factor— This efficiency is the closest approximation to the efficiency defined in the proposed regulation. It is the useful work plus useful thermal energy divided by the fuel input

$$E_{UF} = (W + Q_U) / Q_B$$

Overall Efficiency— This term is defined in the proposed DOER regulation 225 CMR 14.05(8)(b)(2). It is similar to the Energy Utilization Factor above with the inclusion of a energy value (Btu) for any Merchantable Bio-products. As stated in the regulation, merchantable bio-products “shall be prescribed an energy content based on its enthalpy of reaction”. Although a simple definition, the assignment of a value to a chain of complex chemical reactions that are occurring simultaneously with the production of useful thermal and electric may be complex to calculate consistently.

$$\eta = (W + Q_U + Q_{\text{merchantable bio-products}}) / Q_B$$

General Efficiency Notes To further cloud the calculation of efficiency, there are several differing conventions that are used, which make comparisons between various processes difficult. Listed below are some common inconsistencies

Higher Heating Value versus Lower Heating Value

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There are two common methods of stating the heat content (Btu or kJ) of fuels. The Higher Heating Value (HHV) takes into account the condensation of byproducts, while the Lower Heating Value (LHV) does not. This reduces the numerical value of Btus for a fuel expressed on a LHV basis. The difference between the two are dependent upon the constituents of each fuel, range from approximately 5% for coal, 10% for natural gas and a typical range of 6 to 7% for biomass fuels.³ The US power industry typically uses HHV for fuel input in efficiency calculations while the European industry and combustion turbine equipment manufacturers use LHV for fuel heating value basis.

It is important that stated plant efficiencies and equipment efficiencies require units. Typical European plant efficiency quotes will have to be adjusted by the heating value ratio of LHV to HHV to be able to compare values with US plant efficiencies.

225 CMR 14 does not state if the fuel input will be stated as HHV or LHV which can introduce a 6 to 7% difference in efficiencies.

Location for Measurement of Plant Input and Output values

The location and definition of the inputs and outputs of a power cycle must be defined precisely and accurately in order to determine a consistent efficiency calculation. The inlet fuel content can vary from the as received moisture content to the moisture content immediately prior to combustion. Fuel content can also be listed as the bone dry content of the fuel ignoring the loss in heating value due to the moisture in the fuel.

Third party testing of power plants usually measure the plant revenue meter output for the power output. This reading includes any losses associated with step up transformers required to raise the plant voltage to the grid voltage. Other efficiency measurements may elect to read the power output at the generator leads thus giving a higher than normal plant efficiency. In extreme cases, the plant may not account fully for energy used for internal station loads artificially raising plant loads.

Plant output readings at the generator terminals represent the plant's Gross Output. Subtracting the plant auxiliary loads gives the Net Output. The output and efficiency basis (gross or net) should be identified.

Merchantable Bio-products

The term merchantable bio-products has been introduced into the required plant efficiency for REC qualification. The proposed regulations definition is "*For Merchantable Bio-Products the product shall be prescribed an energy content based on its enthalpy of reaction, to be approved by the Department, and those units of energy appropriately converted to MWhs*".

As the standard combustion process is efficient at converting the chemical energy in the incoming fuel to predominately a mixture of oxygen, CO₂ and water vapor, any

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merchantable bio-product removed from the power generation process will lead to a reduced power and thermal output.

The use of a direct conversion of chemical energy into electrical energy with no factor to account for the conversion efficiency will drive the power producer to bypass power generation in place of merchantable bio-product production as a way of meeting the DOE efficiency standards.

As the standard is written, the contribution for merchantable bio-products is 100% versus the contribution for thermal and power are reduced by the cycle efficiency. The result of this will be to increase the biomass input to a facility to generate an equivalent electric output. Given that the biomass resource is fuel constrained due to the economic distances to transport fuel, the net electrical output for each biomass facility will be less.

Cycle Efficiencies for Thermal Power and Chemical Cycles – Figure 3 through Figure 5 illustrate the basic power generation cycles.

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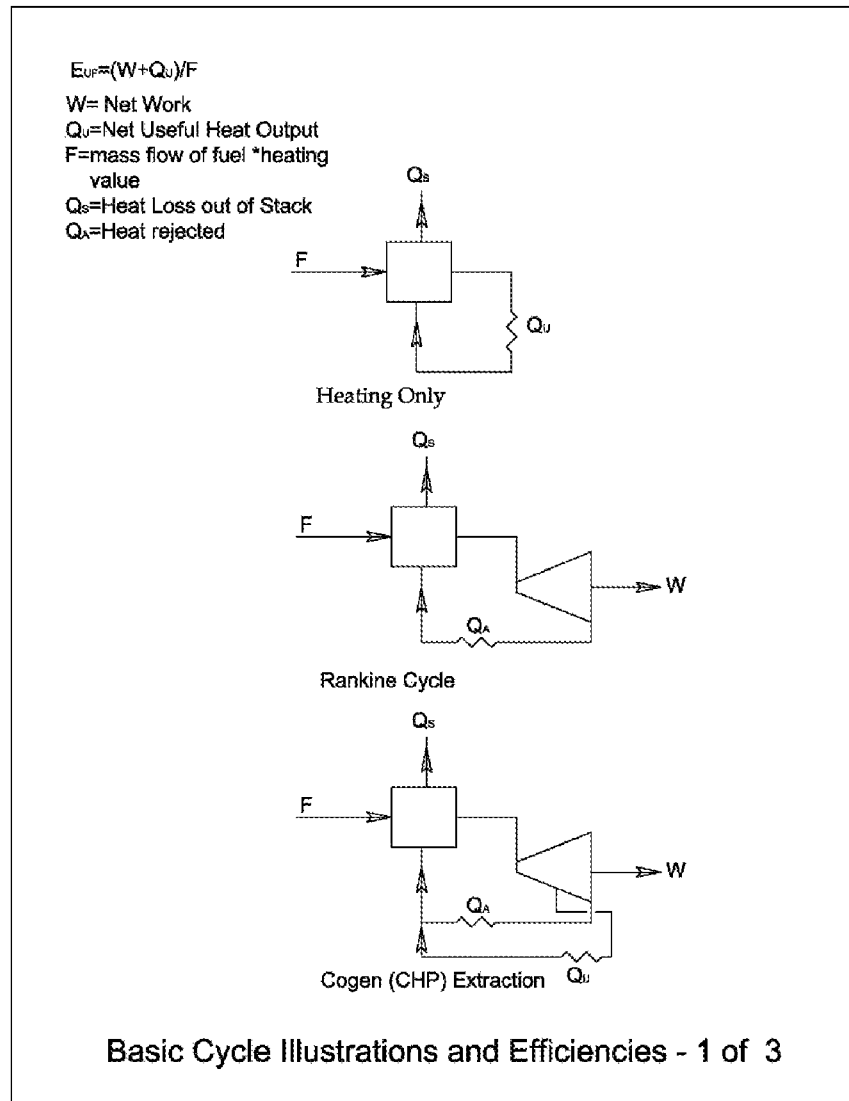


Figure 3

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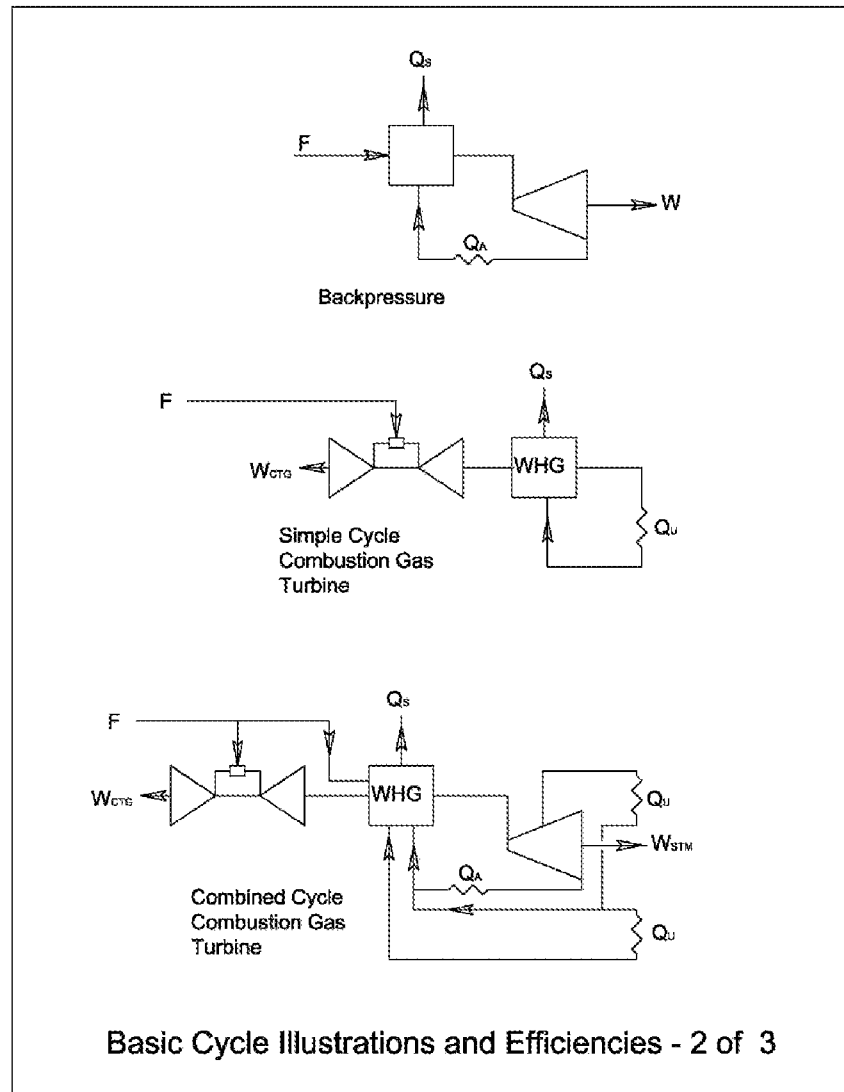


Figure 4

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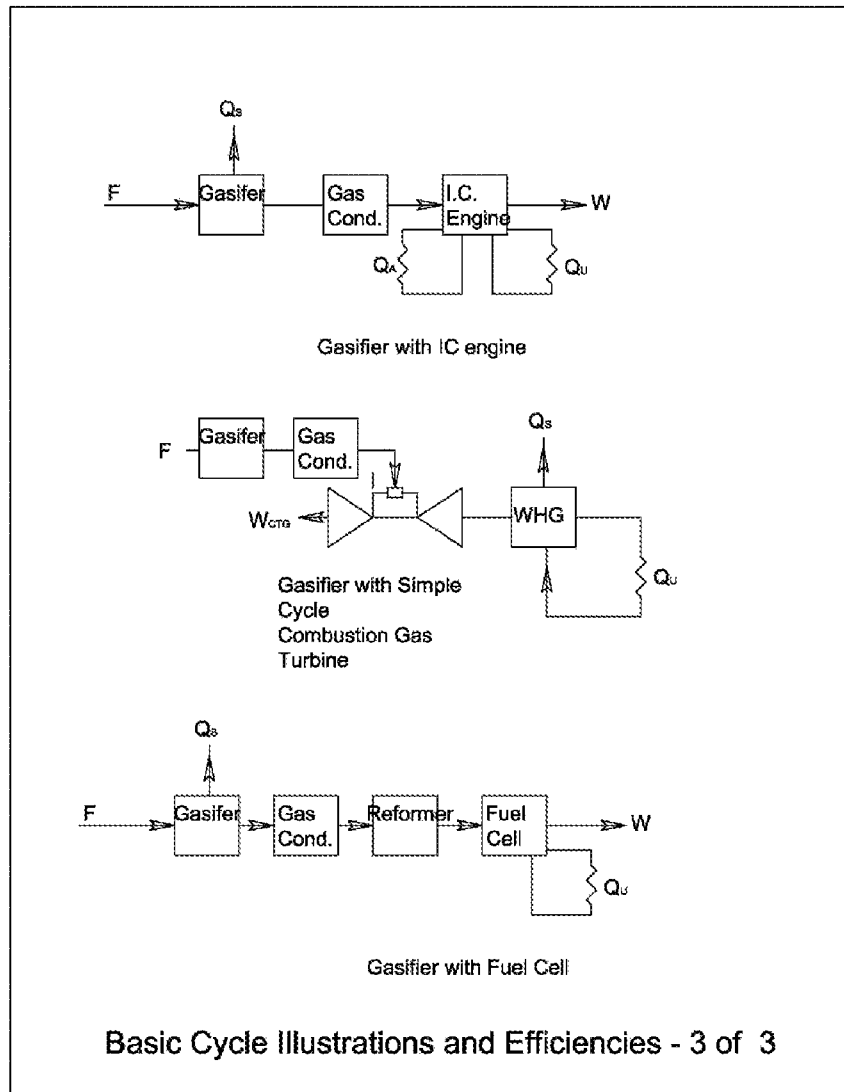


Figure 5

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IV. Technology Discussion

A. Steam Rankine Cycle

The steam Rankine cycle is generally reported to generate 80% of the electric power in the world. The efficiency of the Rankine cycle is a factor of the boiler efficiency and the steam cycle efficiency. The design of the cycle accounts for the tradeoff between efficiency, capital cost, fuel cost, and plant lifetime. Decisions about pressure, temperature, reheat or regenerative heating are based on optimizing the project. All projects have an optimum design that is not necessarily the highest efficiency. The cycle has been optimized to generate the maximum amount of electric power from a thermal supply within cost constraints.

The three major components are a boiler, steam turbine and the heat rejection system. The boiler converts the fuel into thermal energy resulting in superheated steam vapor being sent to a steam turbine. Power plants based on this cycle and typical components are designed for baseload or daily cycling load operation with the maximum efficiency point occurring at or around 85% load. The equipment used is relatively large with a high mass and is prone to differential expansion issues when cycled leading to the desire to maintain the plant warm even during periods of low demand. The basic components and flows of major constituents are shown in Figure 6.

Steam Generators or Boilers

There are numerous variations of boilers used to convert the energy in the fuel to steam. Boiler design depends on the fuel considered. A boiler designed for gaseous or liquid fuels are unsuitable for solid fuels without extensive conversion. Given the smaller size of biomass boilers due to the economics of fuel supply, the biomass industry has used relatively straightforward designs that are flexible in the ability to deal with fuel that varies in particle size and moisture content. Although the typical biomass fuel moisture content is 45% by weight, the boilers are generally designed to accept wide variations in moisture content. The practical limit for combustion is approximately 60% moisture content where the energy required to dry and combust the fuel is roughly equal to the Btu content of the entering fuel.

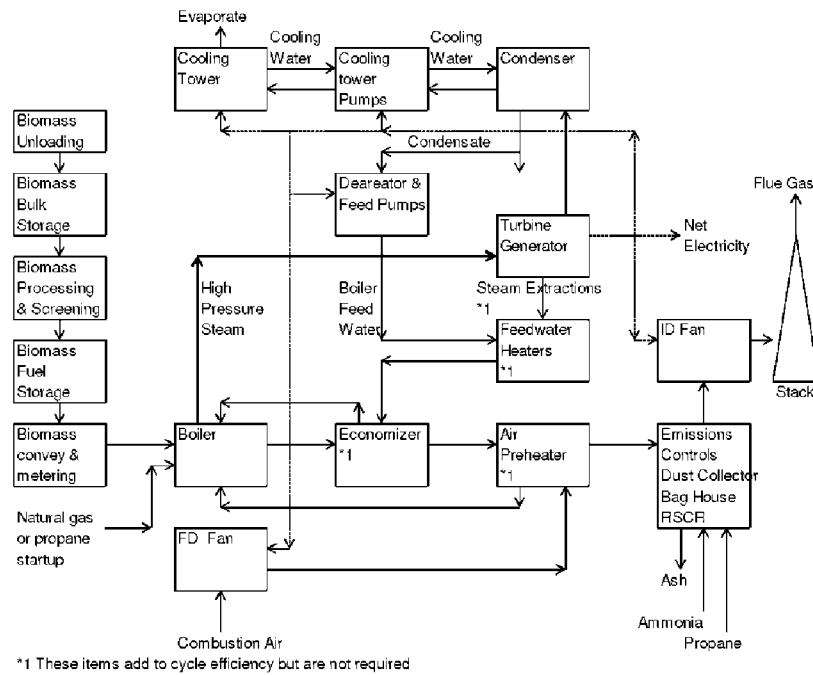
Biomass power generation is usually based on a low value waste products from another higher value wood processing operation. Bark, sawdust, lumber ends, agricultural waste are typical fuel supplies and there can be a high level of non-combustible constituents entrained in the fuel stream that must be accounted for in fuel handling and combustion.

Biomass boilers must also be able to handle a high level of non burnable constituents that are inherent with a low grade fuel resource. This is typically referred to as bottom "ash" which is predominately non carbon containing minerals that can be recycled for beneficial use along with inert gravel and rocks.

The maximum operating temperature and pressure of a boiler is a tradeoff between unit cost and the metallurgical properties of the boiler and the downstream steam turbine. High pressure

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and temperature advanced steam generator designs increase efficiency of the steam cycle but are more expensive to build and maintain.



Typical Rankine Cycle Biomass Power Plant

Figure 6

Rankine Power Plant

Suspension Type Burners

Although rarely used for large biomass generation boilers but popular in coal boilers, a suspension burner requires a finely ground dry fuel supply which is introduced along with a large volume of air to "suspend" the fuel in the combustion chamber of the boiler. Radiant heat

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from the walls and other burning fuel ignite the particles where the combustible constituent's burn and any non combustible materials drop to the base of the boiler.

Given that a typical biomass fuel as delivered is quite high moisture content, this is not a good design for biomass use which usually requires the fuel to be introduced to the combustion zone from a drying zone.

Sawmill facilities use this design on occasion to combust sawdust that is finely ground and is relatively dry..

Hearth Type Boilers

This design is rarely if ever used for modern boilers. Fuel is deposited on a burning bed of coals at the base of the boiler via injection ports or air swept feeders. A portion of the combustion air is injected under the bed to support drying, partial combustion and gasification. Fine particles are carried upwards for subsequent further combustion, while heavy particles remain in the bed until they have broken down into smaller particles. Hearth units are occasionally equipped with sloped vibrating grates to attempt to distribute fuel and coals somewhat uniformly and allow removal of non burnable solids with a manual or automated system. Other systems of this configuration are manually cleaned out on a routine basis. The non uniformity of combustion leads to emissions controls issues and the labor required for ash removal have led to a reduction in their use.

Grate Boilers

Grate boilers are defined as either fixed grate or moving grate boilers. A Fixed grate is similar to the hearth type boiler. Fuel is added and burned on the grate. The ash is removed by hand raking or by the action of new fuel pushing the ash off of the grate.

A moving grate added at the base of the boiler automates ash removal. The grate continuously moves in one direction to assist in spreading of the burning fuel pile and remove non burnable ash and inert solids from the bed. These units are typically equipped with air swept feeders that attempt to spread the incoming fuel uniformly across the face of the bed. The operation of the unit must be adjusted carefully, as un-combusted carbon (char) can be carried past the combustion zone of the boiler into the downstream emission equipment. Unburned char reduces the boiler efficiency because it is energy added to the boiler that is not combusted.

There are also some potential issues with the formation of CO unless careful addition of secondary air is applied. This design is a relatively economical to install and operate and many of the New England biomass units use this design.

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Fluidized Bed Boiler

Bubbling Fluidized Bed Boiler

Bubbling Fluid Bed (BFB) boilers utilize a heated sand bed in place of grates at the base of the boiler. Combustion air is injected under the sand bed at a velocity adequate to partially suspend the sand bed in the air so that it responds in a matter similar to a fluid.

Solid fuel is distributed onto the sand bed, where it partially combusts after drying and gasification. The sand in the bed becomes turbulent and heated which acts to break down the fuel into small particles on a rapid basis. Non combustible ash and inert solid objects fall to the bottom of the bed and are drained periodically using an automated system. The system potentially leads to near complete combustion and minimal char carryover to downstream equipment. BFB boilers have a higher efficiency than grate type stoker boilers that is somewhat offset by higher auxiliary loads for fan power.

Circulating Fluidized Bed Boilers

Circulating Fluid Bed (CFB) boilers use a similar concept to the BFB wherein sand is fluidized by the addition of high velocity air. Unlike a bubbling bed system where the sand is retained in a specific lower zone of the boiler, a CFB unit circulates the hot sand through the entire range of the boiler combustion zone. The fuel is in contact with the sand and effective mixing and combustion allows good efficiency and low emissions.

The entrance to the tube section of the boiler is configured with a cyclone or I-Beams to remove the sand and char from the gas stream to be recycled back into the furnace. This leads to near complete combustion of all burnable carbon in the fuel stream and is of particular value to for hard to burn materials.

The CFB process also is of great value for fuels with contaminants such as sulfur, as lime can be injected into the bed for SO₂ control. Although this technology is very good for coal and solid wastes, it is excessive for small facilities burning clean wood fuel and is very capital and operationally expensive due to the high levels of erosive wear and high horsepower requirements.

Steam Turbines

The steam turbine consists of variously configured internal sections that convert the energy in steam to mechanical shaft power. Each individual turbine is assembled out of various internal sections and optimized to operate under a given range of inlet and outlet conditions. There are two major types of turbines and one major variation

Condensing Steam Turbine

A condensing turbine is designed to obtain the maximum amount of shaft work out of a given steam input. A standalone steam electric generating plant will typically use a condensing turbine to maximize the electric power generation. The condensing turbine is typically the second most

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costly component of a power plant and is designed to operate within specific operational parameters.

A sealed condenser is connected to the discharge of the turbine and operated at a vacuum. The turbine exhaust is a mixture of steam and some water droplets discharged from the turbine below atmospheric pressure. The discharge pressure is directly related to temperature that the condenser cooling water temperature.

As the theoretical (and practical) efficiency is controlled by the energy difference between the inlet steam to the turbine and the turbine exhaust, the efficiency of the cycle is increased as the condenser temperature is lowered. Generally this low temperature is supplied by either a cooling tower that is dependent on the ambient wet bulb temperature, or a cooling water source such as cooling ponds, rivers or ocean. As there are regulatory limits on thermal discharges into water bodies, the use of river and ocean cooling is increasingly rare for small power plants.

Due to the ambient temperature, there is a seasonal change in the plant output and efficiency and the cooling water temperature changes.

Extraction Steam Turbine

A variation on a straight condensing turbine is an extraction turbine. The extraction turbine is designed to allow a designed range of volumes of steam to be extracted from the turbine at intermediate pressures prior to the outlet of the turbine to the condenser.

The steam extraction can be used to supply industrial or commercial processes. The regenerative steam cycle uses steam extraction to heat boiler feedwater to improve the efficiency of the overall cycle. Many of the current biomass power plants in operation in New England have small extraction stages used for feedwater heating to improve the plant efficiency. The number of feedwater heating stages is a function of plant size and the tradeoff between cycle efficiency and cost.

Backpressure Steam Turbine

Backpressure turbines discharge steam at a higher than ambient pressure and temperature, generally for use in an industrial or commercial processes. The units are designed to operate on 100% superheated. The efficiency of the unit is still constrained by the Carnot Cycle and due to the higher pressure discharge a backpressure steam turbine will produce lower amounts of mechanical shaft power at a lower efficiency than an equivalent condensing turbine operated at the same inlet temperature. Backpressure turbines are generally physically much smaller than a similarly rated condensing turbine.

Heat Rejection

The condenser used at the exhaust of the steam turbine is a heat exchanger that operates below atmospheric pressure. The condenser can be cooled with either a cooling water flow or a by air cooling. The majority of the small biomass plants use water for cooling although there are some air cooled units in operation in the region. Most water based systems use cooling towers

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that take advantage of direct cooling and evaporation to lower the cooling water temp to approach the wet bulb temperature of the ambient air.

The cooling tower depends on evaporation as part of the cooling process and requires water makeup to the plant from outside sources.

An air cooled condenser uses far less makeup water at a cost of the loss of evaporative cooling leading to a higher operating temperature than obtainable with a direct cooling tower.

There are hybrid cooling systems that mix attributes of both methods. A hybrid tower is used to reduce the water drift and plume from a wet cooling tower.

A remaining means of cooling traditionally used on larger power plants with access to water bodies is the use of once through cooling water. The use of once through cooling is rare in small biomass plants due to thermal regulations in effect for most water bodies.

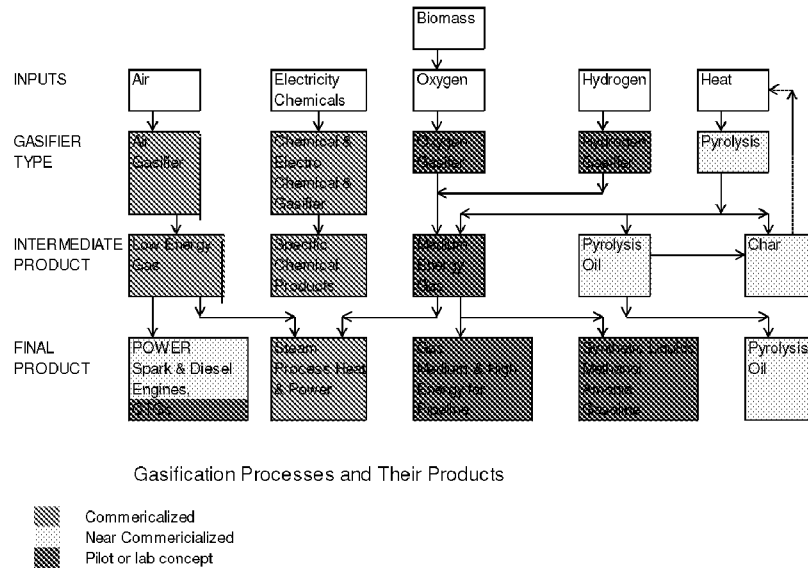
B. Gasification

Gasification is the conversion of solid fuel to gaseous constituents. There are multiple variations on the process dependent upon the source of heat and the relative amount of air used in the process.

Figure 7 illustrates the major variations in gasification technology and their state of commercialization. Commercialization is defined that the equipment is available for sale with emission and performance guarantees and currently in commercial operation with an availability equivalent to commercial generation equipment by a party, other than the manufacturer or developer of the technology.

Small scale under 250 kW units were excluded from discussion due to their low potential impact to regional power.

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Gasification Processes and Their Products

South African processes were excluded from commercialized status as they are predominately coal feedstocks

The Biomass Energy Foundation Press, Nov 2002, 3rd edition T. Reed Fig III-4

The base drawing for this figure was obtained from ⁴

Figure 7

Gasification Processes

Gasification Boilers

Although fuel drying, gasification, combustion, and heat transfer occurs in any solid fuel boiler, the term gasification boiler (or gasifier) typically refers to a low output commercial or institutional two stage device where one stage heats the solid fuel in the presence of low oxygen levels to drive out gases from solid fuel. The resultant gas stream is routed to a refractory lined vessel where additional air is injected into the stream to promote complete combustion.

The high temperature exhaust is routed through a conventional heat transfer device that either generates steam or hot water for either power production or heating purposes. Their major use is in small biomass fired heating plants as the added complexity over a conventional wood boiler is not economic for commercial power generation. An additional use that has proven popular is to install a gasifier section upstream of a conventional gas fired boiler in place of the existing

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gas burners to allow burning solid fuels without an extensive boiler retrofit. A gasifier conversion allows retention of a majority of the boiler structure when switching to wood fuel.

Synthesis Gas or Liquid Gasifiers

Although wood fired gasifiers have been in use prior to the 1940's the technology was substantially abandoned thereafter. The gaseous fuel stream produced by the earlier design direct gasifiers, generally referred to as synthesis gas, had a very low Btu content, high moisture levels and contained condensable tars. The condensable tars caused downstream deposits and the liquids resulting from the moisture and condensed tars were generally corrosive and would now be considered hazardous waste. This technology was developed and used predominately in areas where conventional liquid fuels were in short supply and fell out of favor rapidly once conventional fuel supplies became available. There are still some third world use of this technology, generally in areas with excess biomass and little or no emission regulations.

An advanced level of this technology has remained in limited use in South Africa on coal fueled plants as a means of generation of various products including chemical feedstocks and fossil fuel replacements. By the use of the Fischer Tropsch process, numerous chemical feedstocks can be selectively produced, although typically the cost is such that conventional feedstocks are less costly. Currently in the research or near commercial category are improved versions for the conversion of solid fuel to gaseous or liquid constituents by thermal breakdown. The driver for the resurgence is related to the use of renewable resources in place of fossil fuels for a feedstock which makes the resultant products qualified for significant incentives.

Most of the effort on current gasification technology is to improve the gas treatment systems to produce a higher energy density fuel, low in moisture without condensable tars and contaminants. Small scale units tend to incorporate equipment to sub-cool the synthesis gas stream and attempt to filter out the resultant condensables, thus forming liquid hazardous waste streams. Larger scale units use high temperature catalysts to convert the tars to gaseous forms that will not condense or form deposits.

This technology is currently pre-commercial, nearing full scale trials for small scale biomass fired combined heat and power plants based on internal combustion (IC) engines that are below the economical sizing of conventional biomass plants. These units generally require a higher grade of wood and sizing criteria compared to conventional biomass facilities. Nexterra Systems Corp.⁵ has sold several full scale trial IC based units and is nearing commercial production⁶. Nexterra reports efficiency near 60% but the available published data does not identify whether the efficiency is gross or net and whether it is based on LHV or HHV.

There are pre-commercial attempts at the use of synthesis gas to fire conventional gas turbines. To date there are no existing long term commercial applications with publically available performance results.

Although there are multiple uses and configurations for synthesis gas or liquids, the literature, indicates a range of conversion efficiencies from solid wood to usable synthesis gas at a 60 to

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80 percent efficiency⁷ when fed 20% moisture content biomass. Some processes are capable of operation at higher moisture content, albeit at a lower cycle efficiency. When used as a feedstock for power generation this puts synthesis gas at an upfront disadvantage as the 20 to 25 percent of the inlet energy which has been used to produce the synthesis gas will lead to lower cycle efficiency than obtainable with natural gas or liquid fuels.

It is important to note that most advanced cycles that use gasifiers require low moisture wood and that drying wood to supply the unit is not included in the efficiency quoted.

Pyrolysis Systems

A subset of gasification systems are pyrolyzers that use either direct or indirect heat generally at a lower temperature range to drive off volatile gases or liquids from the biomass feedstock. There are physical differences between a gasification and pyrolysis. In general though, processes that operate between 300°C and 600°C are considered pyrolysis. Processes over 600°C are considered gasification. The temperature and time determined the percentage of char, liquid, and gas that is produced.

The volatile gases or liquids from the fuel can be processed to form merchantable bio-products. Dependent upon process conditions, a combustible char product can be produced that can either be used to heat the process or can be marketed as a constituent of a product called "bio char" or "bio-coal". When Bio-char is mixed with an appropriate blend of organic wastes it is means of low cost carbon sequestration and is used as a soil amendment. There is no currently viable market for this product beyond the demand for research.

Another product of pyrolysis can be a product referred to as bio-oil. Bio-oil can be burned directly in some industrial or commercial boilers or used as a chemical feedstock for higher value products. It is potentially a competitor to rural biomass power plants in that a high value product can be processed local to a waste wood source and transported in a denser form to other markets. The NH Office of Planning commissioned a study "New Hampshire Bio-Opportunity Analysis"⁸ to discuss the commercialization of the technology. Although it is promising from a standpoint of biomass utilization, the process is a net energy user and it is not likely to be a contributor to the regional renewable power generation market.

Dynamotive Energy Systems⁹ has a full scale pilot fast pyrolysis system that generated commercial quantities of char and a liquid fuel referred to as Bio-Oil. The plant was shut down, but is reportedly scheduled to restart in the 4th quarter of 2010. Conceivably this plant could integrate a power generation cycle, although the company appears to be marketing the products of pyrolysis as high value products.

An alternate merchantable bio-product process that has garnered some regional publicity is Maine Bio Products¹⁰ Biofine process which uses a pyrolysis reaction along with other technology to produce chemical feedstocks from the lignin component of the biomass. In addition to the high value chemical feedstocks, char is produced as a byproduct. Although

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another promising biomass use, the process is a net energy user unlikely to contribute to the regional renewable power generation market.

Both of the prior processes and a host of others do not have commercial facilities in place nor are they operational. They are unlikely to be net producers of regional electricity in New England.

Gasifiers for the production of Merchantable Bio-products

As discussed in the introduction section, given that the combustion process is quite efficient at converting the chemical content of the fuel to gaseous byproducts, the removal of merchantable bio-products from a power or CHP cycle will reduce the plant output since the energy in the fuel is removed from the process and is not used for power generation. Although the Commonwealth's proposed regulation is written to address the generation of renewable power, it has the indirect effect of incentivizing the generation of merchantable bio-products at the expense of power generation.

C. Gasification for Gaseous or Liquid Fuel Cycles

The use of synthesis gas is not yet commercialized for most direct combustion purposes; there is much discussion of this potential in the literature. Using internal combustion engines with biomass gasifiers for CHP is close to commercial production. If the technical and economic hurdles are overcome to convert wood synthesis gas into a clean usable gaseous fuel with adequate properties for use in direct combustion devices, gas and liquid synthesis streams could become the fuel supply for several power generation cycles. Fuel supply limitations and capital cost considerations limit the construction potential until there is a substantial, stable, long term incentive for the production of renewable power. That said, the technology is not currently commercialized.

Figure 8 shows expected efficiencies and commercialization status of the major gasification cycles when operated on biomass synthesis gas.

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Cycle Efficiency for Combined Heat and Power Systems operating on biomass fuel														
Combustion Unit Type	Units	CTG - CHP	CTG - CHP	CTG - CHP	CTG - CHP	CTG - CHP	CTG - CHP	CTG - CHP	Biomass IGCC	PA Fuel Cell	PEM Fuel Cell	MC Fuel Cell	SFO Fuel Cell	ORC/CHP *4
Commercial Biomass Installations?		Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	
Electric Capacity - primary	KW	1200	2400	10000	25000	40000	10000	3000	20000	200	200	2000	100	2175
Electric Efficiency nat. gas (HHV basis)	%	22%	22%	22%	24%	27%	29%	29%	21%	28%	29%	48%	43%	NA
Fuel Input nat. gas *1	MMBTU/hr	19.2	82.8	117.7	248.8	368.8	10.4	48.8	2768.8	1.3	1.0	14.3	9.8	NA
Heat Output	MMBTU/hr	7.1	26.8	45.8	95.5	136.8	3.3	15.8	0.0	0.27	0.00	1.80	0.10	32.07
Suitable High Temp District Heating?		Y	Y	Y	Y	Y	Partial output	Partial output	Y	N	N	N	N	N
Heat Generation efficiency on nat. gas	%	48%	42%	42%	38%	37%	32%	32%	0%	18%	0%	17%	17%	NA
Electric eff. on synthesis gas at 75% conv.	eff.	15%	16%	20%	24%	26%	25%	27%	24%	25%	24%	32%	26%	NA
Heat Generation efficiency on syn gas at 75% conv.	eff.	34%	32%	32%	26%	28%	27%	26%	0%	13%	0%	10%	9%	NA
Total Conversion efficiency on syn gas at 75% conv.	eff.	51%	52%	53%	50%	54%	52%	53%	24%	38%	24%	44%	41%	NA
Total Conversion efficiency on syn gas at 80% conv.	eff.	56%	57%	57%	56%	59%	57%	56%	24%	41%	27%	47%	44%	60%
No Commercial Applications Commercial installed applications														
*1 - C engine value converted to HHV from LHV using 10% derate value for LHV *2 C engine steam generation calculated using 85% exhaust to steam conversion *3 The temperature of the heat generated varied with the data sources for individual systems, if identifiable, heat below 180 F was not included in this calculation *4 Organic Rankine Cycle thermal output is limited to 194 degrees F output, data is only available for biomass input at 70% combustion efficiency														
Data Sources: Simple Cycle CTGs - http://www.energy.solutionscenter.org/distgen/AppGuide/Chapters/Chap4/Images/Table_4-3.jpg C engines - http://www.cet.com/data/components/assuredFieldsdisplaySecuredFileServletUSP?language=7&fileId=202077 http://www.energy.solutionscenter.org/distgen/AppGuide/DGuideFrameSet.htm Combined Cycle CTG - http://www.netl.doe.gov/energyanalysis/pubs/Btuminous%20Baseline_Final%20Report.pdf Fuel Cells - http://www.energy.solutionscenter.org/distgen/AppGuide/Chapters/Chap4/Images/Table_4-6.jpg Organic Rankine cycle http://www.turboden.eu/en/public/downloads/charts/A4%20Biomass%20cycle%20pl%20NG.pdf														

Figure 8

Cycle Efficiencies for Biomass CHP Systems

Simple Cycle IC based CHP plant

The use of synthesis gas for CHP in IC engines is near or at the commercial stage with some customer units in place. The units reportedly are not economically competitive with conventional heating and power generation systems due to the high initial capital cost and competing fossil fuel prices, but are in some demand for demonstration projects where a premium for renewably

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powered electric and thermal is applied; and incentives are available to offset the initial capital cost. There are inherent limitations in the internal design of this type of gasifier that limits the efficient output to an internal dimensional limitation and therefore generation of large amounts of electrical power must be accomplished in multiple units thereby limiting the economy of scale. The best fit for this technology is currently for onsite "behind the fence" generation in one to two MW gross electrical output blocks

Simple Cycle Combustion Gas Turbines

There currently are no CTG's that could be located in commercial long-term use operating on synthesis gas. Although the application is similar in concept to an IC application, CTG systems are a better fit for large scale power generation as CTG's are offered in a wide range of sizes and have a very small equipment footprint for the equipment electrical output. These systems will require the use of a different configuration gasifier in order to operate at the higher CTG fuel flow requirements. They are much simpler to operate than a steam Rankine cycle and do not require licensed personnel to operate. The limitations to the CTG are the tight internal tolerances and fuel quality specifications. CTG's are more susceptible to fuel deposits than IC engines.

Simple Cycle Micro turbines

A subset of conventional CTG's that compete with IC engines are micro turbines (generally less than 1 MW) offered by several manufacturers. These units are typically intended for behind the fence applications where there is constant thermal demand. Although there are units rated for low Btu syngas, there are no commercial systems offered at this point that integrate a gasifier with fuel conditioning and the turbine in one package. Although the units are rated for syngas, their fuel quality requirements are considerably more stringent than IC engines.

Micro turbines are highly susceptible to fuel contamination making operation on synthesis gas difficult without extensive upstream conditioning and filtering. Given the low Btu content syngas from wood waste and the significant number of processing steps to generate syngas of sufficient quality to operate a micro-turbine, it is doubtful if the capital and operational costs for this technology will be attractive in the near future.

Heat Recovery from CTG units

The resultant exhaust heat from the units can be directed through a heat recovery device that generates either steam or hot water. The exhaust temperature from either device is in the range of 800°F to 1000°F dependent upon actual configuration.

Combined Cycle Plants

Natural gas fired Combustion Turbine Combined Cycle (CTCC) plants are a cost effective, high efficiency technology for use with natural gas or liquid fuels. The main driver is the development of high efficiency CTG's. Given the increase in CTG and CTCC efficiency, the availability and pricing of natural gas, and the ability to quickly permit and construct facilities, a large number of

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cycling and baseloaded units have been installed across the country over the last decade. Like a simple cycle gas or liquid plant, the fuel is combusted in a CTG and the hot CTG exhaust gas energy is recovered in a Heat Recovery Steam Generator (HRSG) to generate high pressure steam where it is converted to power with a condensing steam turbine.

CTG inlet combustion temperatures are combined with the far lower (near ambient) discharge temperatures of the steam Rankine cycle leading to a high overall plant electric generation capacity. These plants are intended as electric power generation plants, as any thermal energy extracted above the steam turbine condenser temperature will lead to a reduced cycle efficiency. Typical efficiencies range from 40% to over 60% (LHV).

The tradeoff for this design is that the plant complexity increases from a simple cycle plant as there are two power generation cycles required. The plant size is most economical between 250 MW and 1500 MW. Although, there are extensive CTG based cogeneration plants located in the United States.

Large 250 MW biomass based CTCC plants would be too large to be fueled economically from renewable waste wood supplies, as the radius of required fuel supply area would exceed the range where the fuel and resources required to haul the fuel would exceed the fuel value of the wood. Smaller plants could be built, but the capital cost per MW increases as the plant becomes smaller. Commercial application of the CTCC to biomass will require advances in hot gas cleanup to ensure the plant can operate reliably.

D. Other Power Generation Cycles

There are numerous alternative power cycles mentioned in the literature. Generally, however, they are a variation on current cycles. Many are in the early development scale, so published actual long term operational and efficiency data is not readily available.

Sterling Cycle Power Plants

A technology that is mentioned often in the literature is the Stirling cycle, generally referred to as an "external combustion engine" or occasionally a "heat engine". The cycle uses an internal working fluid that is heated and cooled externally to generate power. It is a heat engine and constrained by the Carnot cycle with similar internal frictional characteristics as IC engines. The major advantage to the cycle is the ability to use a variety of heating and cooling sources to generate power. As combustion is external to the engine, the fuel quality should potentially allow a lower grade of fuel to be burned to heat the unit. Although long mentioned as a possible future power generation cycle due to its theoretical efficiency and fuel flexibility, to date it has been notoriously difficult to commercialize. Currently the major use of Stirling generators are for solar to electric power generators with one large scale deployment in operation in the US west with another recently approved for California. There have been niche applications being developed for microscale CHP use with one commercial unit made by Whispergen¹¹ in production.

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Organic Rankine Cycles

Organic Rankine Cycle (ORC) systems utilize low boiling point fluids as an alternative to steam in a conventional Rankine cycle. By using organic fluids with low boiling points, the ORC system can capture waste heat from other sources and generate electric power.

The ORC unit is a Rankine cycle, and its efficiency is constrained by the Carnot cycle. The primary value of an ORC unit is for dealing with relatively low temperature waste heat sources that are too low to economically generate power with conventional steam systems. ORC equipment, manufactured by Turboden,¹² is currently used in European pellet manufacturing processes where large volumes of relatively low temperature heat are required. When matched with an appropriate thermal demand, this equipment reportedly has high overall fuel utilization efficiency, well above competing technologies. Although capital intensive, the combination of high feed-in tariffs and high cycle efficiencies appears to be economically attractive in the European market for wood pellet production. In the US, ORC is being used for geothermal power plants and is being advocated for use as low temperature heat recovery units. Currently the low efficiency and high capital costs of small scale equipment have restricted the use to subsidized pilot applications.

Entropic Cycles

There is little publically available information on this power cycle.¹³ The Entropic Cycle appears to be targeted for similar small electrical output applications as Organic Rankine Cycles. The claimed thermal conversion efficiency is 71%, with a 194 deg F thermal outlet temperature. It appears to be a thermodynamic concept with no reported pilot or commercial installation.

Fuel Cells

Although a fuel cell is not a thermal cycle, it is capable of generating energy from a chemical fuel stream leading to the technical possibility of the operation of a fuel cell from a biomass gasifier stream.

Current fuel cell technology is oriented towards the use of hydrogen as a fuel source, with upstream reformer technology used to separate the hydrogen from the carbon molecules to allow use of hydrocarbon fuels. Current systems in use are highly susceptible to catalyst "poisoning" requiring careful high levels of contaminant removal upstream of the cell. Dependent upon the reformer technology used, either CO₂ or CO is formed as result of reforming. These two compounds generally act as "poisons" in the catalysts used in the fuel cell and therefore high fuel purity is required. The proton exchange and solid oxide fuel cells both operate at relatively low temperatures and therefore the thermal output is too low for most applications

There are research scale fuel cell technologies including Direct Methanol Fuel Cells that can burn methanol which can be produced via biomass gasification and reforming. There are two variations of fuel cells, Molten Carbonate Fuel Cells and Solid Oxide Fuel cells that have the capability of processing CO directly. Both technologies are in the pre-commercial phase for

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large systems. There are some small scale units (less than 20 kW) currently marketed for high value specialized applications.

Typical Fuel Utilization Efficiencies for Biomass Fueled Power Cycles - Figure 9 shows the typical cycle efficiencies of various power cycles from multiple sources. As noted, the Organic Rankine Cycle system efficiency for the commercial system is capable of high cycle efficiency only when there is a demand for low temperature, 180°F thermal output.

Name	State or Prov	MW	Heat Rate	PSI	Temp	Boiler Type	Condenser	Wet Bulb Temp °F	Carnot Eff	Reported Eff. KW/Heat Rate *3	Actual eff./Carnot eff.
1 Williams Lake	BC	60	11700	1575	950	Stoker	CT	57.5	63%	29%	46%
2 Shasta	CA	49.9	17200	900	905	Stoker	CT	62.3	62%	20%	32%
3 Colmac	CA	49	12400	1255	925	Fluid Bed	CT	76.4	61%	28%	45%
4 Stratton	ME	45	13500	1485	955	Stoker	CT	66.7	63%	25%	40%
5 Kettle Falls	WA	46	14100	1500	950	Stoker	CT	64.3	63%	24%	39%
6 Grayling	MI	36	13600	1280	950	Stoker	CT	71.7	62%	25%	40%
7 Mc Neil	VT	50	14000	1275	950	Stoker	CT	70.7	62%	24%	39%
8 Multitrade	VA	79.5	14000	1500	950	Stoker	CT	75.6	62%	24%	39%
Average for 8 plants with expected heat rates									62%	25%	40%
9 Madera	CA	25	20000	850	850	Bubbling	CT	69.3	60%	17%	29%
10 Chowchilla II	CA	10	20000	650	750	Bubbling	CT	69.3	56%	17%	30%
11 El Nido	CA	10	20000	650	750	Bubbling	CT	69.3	56%	17%	30%
Average Values for 11 biomass plants reported									61%	23%	37%

Figure 9

Typical Cycle Efficiency

V. Fuel Quality and Cost

The biomass fuel used by conventional merchant power plants has little use to other buyers. The plants are typically equipped with extensive processing to preprocess the biomass for combustion. The fuel stream includes some sawmill residual, bark from debarking operations, whole tree chips including branches leaves and twigs and on rare occasion bole log chips composed of the main trunk of the trees. All of these fuels have particular handling

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characteristics that generally require blending of the fuel and extensive processing equipment to remove non burnable contaminants and resize fuel to within a range of sizing that can be metered successfully into the boiler.

As the fuel input requirements of the boiler decreases to smaller boiler systems, the fuel characteristics must be more uniform. The recommendations for small scale school thermal only boiler systems installed in many Vermont school districts¹⁴ has led to the recommendation that only bole tree chip or residuals from specific manufacturing operations be used for fuel. If this experience is applied to potential future installations of small biomass CHP units in Massachusetts, this will tend to drive the market for CHP quality chips to a higher grade more uniform and costly wood product than the biomass product currently used by the merchant plants. As this higher grade wood is in demand for wood pellet manufacturing applications, the cost will inevitably increase, and lower grade biomass will be underutilized.

VI. Cogeneration Discussion

Thermal Demands for Waste Heat

In order to generate electricity in a thermal process, low temperature thermal energy must be removed from the power generation process. If there is demand for the thermal energy, the temperature and quantity of the thermal demand will establish the lower operating temperature of the power generation cycle. There are two options for thermal demand-- industrial processing and district Heating and cooling. Thermal demand is directly linked to the power generation of the system. If the thermal demand decreases and there is no other way to remove heat from the system, power generation will decrease.

Industrial Processing

The demand for thermal energy at industrial facilities' is as variable as the industries themselves. A broad generalization is that the majority of thermally intensive processes use steam to directly heat processes and reactions, with the maximum process temperature required generally setting the temperature from the boiler (or turbine extraction).

Intermediate, heat transfer fluids may be used internal to the process, but generally the heat transfer fluids are heated directly by steam from a central boiler. In some processes, gas fired infrared radiant heaters or electric resistance heat is used in specialized areas, generally in facilities with no central heating plant.

In addition to direct thermal processing, a large load demand is drying of products generally by the use of steam to air heaters which typically condense the steam to a saturated water mixture. The steam coil air heaters typically heat large volumes of air which is used to reduce the moisture content of materials, speed up solvent release or speed up cross-linking in polymer systems. Most long term facilities have implemented energy conservation methods, if economically viable, wherein heated exhaust streams are used to preheat incoming air or materials. In addition to process specific thermal demands, inevitably there is a space heating

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and cooling demand that is dependent upon the outside temperature. Space heating and cooling will be discussed in detail in the district heating section.

At times, regulatory policies and energy costs have made the installation of cogeneration systems at industrial sites attractive and there are many large facilities that have contracted with third parties to install these systems as the expected rates of return for power generation does not typically match up with the expected rates of returns for industrial processes.

Building a cogeneration system adjacent to the manufacturing facility presents a power developer a long term issue in that the design and operation of the power generation facility is dependent upon an external party, the owner of the industrial process. If the industrial process shuts down, the power plant project economics may be substantially affected¹⁵. In general, the linkage of a power facility to a specific manufacturer introduces significant long term investment risk into the decision to build a cogeneration plant.

District Heating and Cooling

Outside of internal use by the power plant for the processing and production of merchantable bio-products, the potential use of this thermal energy is generally directed at the space heating needs of adjacent structures. The distribution of heating for space thermal demands is generally referred to as District Heating (DH) systems. There is also potential to provide cooling in a district energy system, generally referred to as District Cooling, although low operating efficiencies, high capital cost and the thermal constraints imposed on CHP plants makes this a less attractive option in most areas except for high density cooling loads.

District heating systems are capital intensive and require dense, urban scale applications to be cost effective. In less dense applications, heavy infrastructure subsidies are required for DE to be cost effective. The capital requirements and location is directly contrary to the fuel needs and the operation of a typical biomass power plant which requires significant acreage for fuel storage and processing along with extensive truck deliveries. Like many industrial operations, operating on a 24 hour per day, 350 day basis, a biomass plant is typically not compatible with the residential and light commercial activities in many cities.

Implementation of a new district heating system is difficult as there is little incentive for potential customers to make use of the service when there is a substantial upfront cost to convert existing heating systems to operate with district heating. Infrastructure issues are substantial as the systems need to be installed in either public right of ways or on negotiated right of ways over private property. There are reliability concerns that must be overcome until multiple combustion units are in place and connected to the system to allow some redundancy to cover unexpected power outages of thermal sources.

There are two forms of DE systems in common use, High Temperature and Low Temperature.

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High Temperature District Heating

District energy systems were developed and still in use in some urban cities in the United States. The systems in operation are high temperature systems that use steam. The steam is routed to primarily commercial and governmental facilities in city centers, using insulated steam and return condensate pipes. Each facility served by the system is connected to the district system via two underground pipes, one carrying steam into the building and one carrying condensate back to the district energy plant. The underground infrastructure for these systems is capital extensive and can be a major issue in the installation or extension of systems in any but dense urban areas with access to low cost capital.

Steam used by the customer is condensed and returned via a smaller diameter pipe back to the district heating plant for reuse.

Building cooling can be provided with additional piping from a central plant or with remote the installation of absorption type cooling units, although their economic use is generally restricted to high value commercial applications due to absorption chillers low efficiency and capital cost. The advantage of absorption chillers is the balanced steam load year round.

The market for district heating in college campuses is driven by the initial capital cost of the system balanced against the reduced need for maintenance of individual building heating systems.

High temperature systems are generally fed by multiple boilers to provide seasonal load adjustment and maintain system reliability.

Low Temperature District Heating

Low temperature district heating systems use hot water for heat transfer to the district's customers. Unlike a high temperature system, the water temp is generally inadequate for use as driver for absorption cooling which substantially reduces any opportunities for summer thermal load demand. The use of hot water in place of steam requires larger diameter supply and return piping for an equivalent heat load. The system temperature is constrained by the use of pre-insulated engineered thermoplastic piping systems that have lower installation costs and installation requirements than steam piping used in high temperature systems. The possible lower installation costs are offset by increased pumping costs and the need for either smaller heating plants placed close together or the use of hybrid systems, using separate dedicated steam lines to reheat the low temperature water systems.

The development of low temperature district heating is dependent upon a significant amount of regulatory incentives, fossil fuel tariffs, carbon reduction incentives and building design standards to be cost effective. Combinations of these have been put in place at differing levels in the European countries that are actively maintaining and installing these systems. Each country uses a different combination of publicly owned or user owned systems. A combination of incentives and penalties on the government's part provide support for these systems. Although the incentives/penalties vary by country the following issues have to be addressed

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Low temperature district heating system temperatures do not support the use of fin tube radiation (typically used in many existing New England homes and commercial properties), unless an electric heat pump system is used to raise the water temperature. A combination of regulatory requirements, high energy costs and building standards, have been used in Europe to encourage/require installation of radiant type heating systems that are capable of operation at much lower source temperatures, thus reducing the need for heat pumps. Retrofitting an existing structure with radiant type heating is expensive and is a cost born by the building owner. Most US commercial systems also require higher temperature source water and will require either a heat pump to raise the water temp or the replacement of the heating coils in the HVAC units.

The overall heating demand per customer needs to be as low as possible to reduce the size of the installed district heating infrastructure. High tariffs on fossil heating fuels and building codes that require minimal energy usage generally have been used in Europe to drive the heating demand down per unit volume. The current regulatory approach in the US has been limited to voluntary incentives to encourage upgraded efficiency. Although building efficiency standards are now in place in most New England areas, the majority of new construction tends to be in low density rural settings with the core of the housing stock in urban areas consisting of older less energy efficient systems.

Governmental support/ownership of district heating systems is generally required to subsidize the high capital costs and low investment returns. Regulatory incentives including "must connect" requirements and heating fuel utilization efficiency requirements create an incentive for high customer participation.

Impact of District Heating Thermal Loads on Electric Power Generation

As shown in Figure 10, a typical central Massachusetts heating and cooling degree days and the ISO electric load are plotted for a typical year.

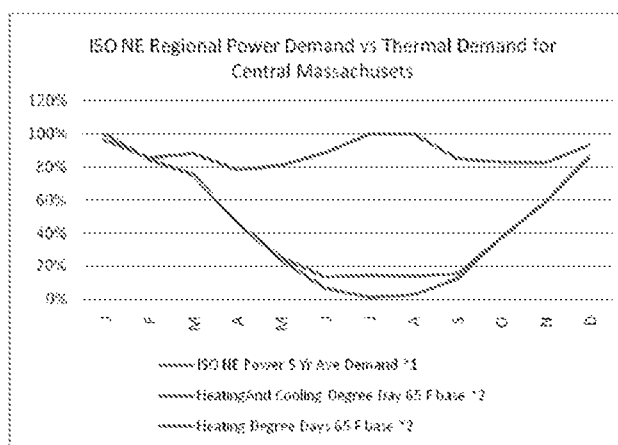
The thermal heating demand for the Worcester Massachusetts based on the Worcester airport data varies widely from a winter peak to a summer period with no heating demand. Worcester Mass. was selected as it is near the center of the state and therefore should be representative of the typical thermal demand curve for the state. The thermal loads and the ISO NE power demand are shown as the percentage of the monthly peak demand for purposes of comparison.

If the demand for summer time cooling is added to the thermal demand there is some summer load, although supplying this summer cooling demand would require the use of a high temperature district heating system to supply adequate temperature levels to supply absorption type cooling units. The high temperature system increases increase the outlet temperature of the accompanying power generation cycle in a CHP plant, and reduces the plant efficiency. Given this wide variation in thermal demand, the demand for useful thermal energy from a district heating system is very limited during the periods of the highest summer time load demand.

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In a district heating application The lack of a continuous thermal load demand over the yearly makes it financially unattractive to connect a CHP to a district heating network as it will only be able to receive REC incentives during times of high thermal demand in the winter, early spring and late fall. It will be unable to receive REC incentives during summer periods when the demand for power is the highest.

As the power demand will remain during summer periods, fossil fueled power generation plants will have to generate additional power to compensate for the lack of renewable CHP produced power.



*1 Data for power consumption from ISO New England

*2 Degree Data from 2009 ASHRAE Climatic Conditions for Worcester Mass Regional airport.

Figure 10

New England Heating/Cooling Degree Days

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Biomass Project Economics

The project economics for a biomass facility are directly related to size and scale of the biomass power plant. The key aspects of biomass power generation are the project size and the fuel cost. Fuel cost is largely transport distance dependent. The plant size determines the capital that can be directed toward efficiency.

New England Biomass Plants

Large biomass power generation facilities have better economies of scale. However, larger units are designed to a different standard compared with small units. An optimum size for a biomass power generation facility is about 50 MW. Most of the existing biomass power plants in New England are 15 MW to 30 MW. A list of biomass power generation facilities is shown in Table 1. Note that Boralex Stacyville was not listed in the database.

Table 1
Current Operating Biomass Power Facilities in New England¹⁶

State	Plant Name	Nameplate Capacity (Megawatts)	Energy Source 1	Energy Source 2	Initial Year of Operation	Unit Status
Operating units						
ME	Boralex Ashland	39.6	WDS	DFO	1993	OP
ME	Boralex Fort Fairfield	37.5	WDS		1987	OP
ME	Boralex Stratton Energy	45.7	WDS	DFO	1989	OP
ME	Boralex Livermore Falls	39.6	WDS	DFO	1992	OP
ME	Greenville Steam	15.6	WDS		1988	OP
ME	Indeck West Enfield Energy Center	27.5	WDS		1987	OP
NH	Bridgewater Power LP	20	WDS	DFO	1987	OP
NH	DG Whitefield LLC	16	WDS		1988	OP
NH	Pinetree Power	17.5	WDS		1986	OP
NH	Pinetree Power Tamworth	25	WDS		1987	OP
NH	Schiller	50	WDS	BIT	1955	OP
NH	Springfield Power LLC	16	WDS		1987	OP
VT	J C McNeil	59.5	WDS	NG	1984	OP
VT	Ryegate Power Station	21.5	WDS		1992	OP

Biomass Project Costs

The project costs for new power generation units have risen dramatically over the last four years. Today, a typical 25 MW biomass power project is assumed to cost about \$112.5 million or \$4,500/kW compared with an expected cost of about \$2,500/kW in 2006.

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The most recent biomass project is Snowflake in Arizona. The project was completed in 2007. The project costs are reported to be \$2,200/kW with used, reconditioned equipment.

New, 50 MW projects have reported an EPC cost of over \$4,000/kW¹⁷

A comparison of plant costs in 2003 versus 2008 is shown in Figure 11

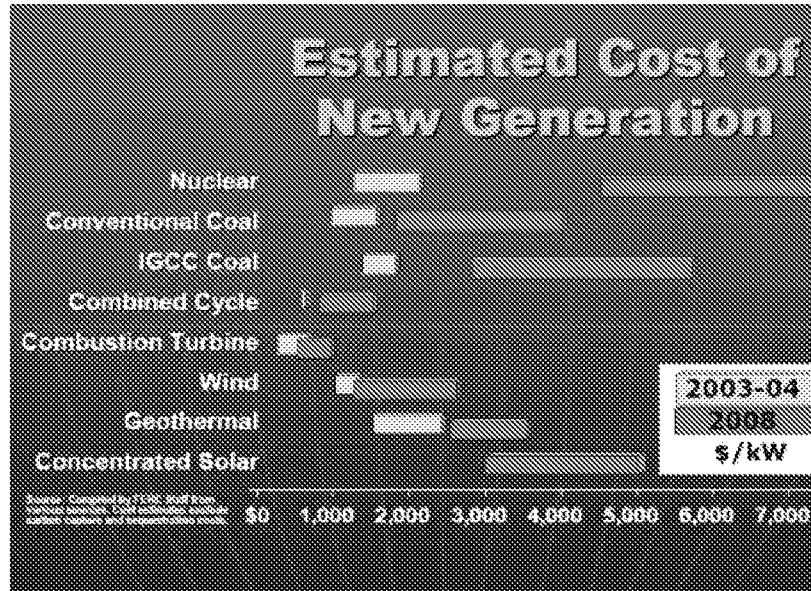


Figure 11

Power Plant Construction Costs

Comparison between Fossil Fired Plants and Biomass

Often biomass plants are lumped in with other solid fuel plants when discussing design and economics. The general differences between a biomass facility and a fossil power plant are:

- Fossil plants are characterized by a large infrastructure associated with coal mining and transport. Fossil plants are located near rail and high voltage power lines. Biomass has highly decentralized harvesting and transport infrastructure. The source of biomass fuel is local and is transported by truck. A typical radius for fuel sourcing is 60 miles to 75 miles.

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- Biomass is expensive to handle and transport. Coal is an energy dense fuel with a heating value of about 12,500 Btu/lb (AR). Wood has a low heating value of about 4,400 Btu/lb (AR) assuming a 50% moisture content. On a per volume basis wood is about 1/3 the energy density of coal. Moving biomass by truck adds transport cost that makes project economics difficult for long haul distances.
- Large utility sized fossil plants can take advantage of scale. The larger fossil facilities have better economics due to better fuel cost, higher efficiency, and reduced staff.
- Coal plant efficiency is demonstrating incremental efficiency gains with high temperature, high pressure, and double reheat supercritical Rankine cycle designs and advanced Integrated Gasification Combined Cycle (IGCC) designs. The highest reported efficiency for a coal fired ultra-supercritical steam generator is 42.5%.
- Improvement of biomass cycle efficiency is in a nascent stage and is not available on a commercial or economic scale. Even if a biomass plant could reach 42% efficiency, advanced cycle design is not economically attractive for small biomass facilities competing with natural gas, combined cycle based power prices in the market.
- Biomass boiler efficiency is limited due to the moisture content of the fuel.

Biomass Pricing and Delivery

Biomass power generation is limited to the availability of biomass. A typical facility is based on the available wood that can be reasonably harvested within transport range of the plant. A typical biomass project is 15 MW to 30 MW in size based on the wood available within a region. A typical economic radius for a biomass plant is 75 miles. Beyond 75 miles, the transport costs raise the cost of fuel and the resultant cost for electric power produced by the plant. As an example, the raw wood cost is typically \$4.00 to \$10.00 per ton. Harvesting is \$12/ton to \$18/ton. Assuming a transport cost of \$0.10 per mile (round trip) a 75 mile radius adds \$15 per ton to the fuel cost. For comparison, the average delivered biomass price is assumed to be \$30/Ton as Received (AR). Assuming 40% moisture the delivered fuel price is \$50/Ton (BDT)

Large biomass facilities are feasible where substantial biomass resources are available, or where transportation such as rail makes additional fuel available, albeit at a higher overall handling cost. The optimum plant size is generally considered to be 50 MW. Larger 100 MW plants have been proposed where fuel is available. Within the 15 MW to 25 MW size, there is a balance between technology cost, fuel cost, and plant cost.

An additional issue for biomass power plant location is delivery of fuel. Normally, fuel is delivered using truck transport. The number of trucks per hour can be an issue in urban areas. A 50 MW biomass plant requires about 70 truckloads per day or 140 trips.

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Rail delivery eliminates the truck transport issue but requires multiple fuel handling steps that increase the delivered fuel cost.

Biomass Plant Efficiency

A survey of biomass plants in the United States indicates that the heat rate for power generation at biomass leaders in the industry was between 11,700 Btu/kWh (29.2%) and 20,000 Btu/kWh (17.1%)¹⁸. Eleven plants were reviewed in the United States and Canada. The Average efficiency was 14,840 Btu/kWh (23%).

The actual operating efficiency of a plant is not the same as the design efficiency. Variables such as the fuel moisture content and ambient temperature have an effect on the plant efficiency. The actual plant efficiency may be +/- 3% from the average.

The best reported efficiency for a biomass steam plant is 35%. The plant costs are not readily available. Königs Wusterhausen was placed into operation in year 2003. The facility is a 20 MW reheat cycle with a reported gross efficiency of 36.4%. This efficiency should be examined to ensure that the reported efficiency is on the same basis as used in the United States. Comparing US reported efficiency with European facilities requires adjustment for:

- The US uses Higher Heating Value (HHV) compared with the European Lower Heating Value (LHV). This is typically 6 to 7% difference which leads to a 6 to 7% overstatement of efficiency as compared to US.
- Gross efficiency does not account for the plant electrical load (parasitic load). Net output is the gross output less the plant auxiliary load. This value varies by plant design but a general range is 10% to 15% of gross output is consumed for plant loads.
- The fuel moisture was not reported. Often European designs are based on low moisture content biomass fuel of 20%, compared with New England typical biomass moisture content of 40% to 50%.

The net efficiency for the Königs Wusterhausen facility is expected to be 29% % (HHV) or (11769 Btu/kWh).

Cost data for Königs Wusterhausen is not available. However, the plant was partially subsidized, received carbon credits, and is in a power market that has a residential rate of €21.1 (\$0.30/kWh). The plant received a €7.71 feed in tariff exclusive of other credits for low carbon generation.

The Biomass IGCC at Varnamo, Sweden¹⁹ (CHRISGAS) is a small 6 MW electric, 9 MW thermal pressurized, CFB plant operated and was mothballed in 2000. The unit is not commercially operating. It's history is limited to 3,600 hours of operation. The reported electric efficiency was 32% (LCV) and would be equivalent to 30% (HHV).

The major issue with the facility was the hot gas cleanup system. Similar issues were experienced with the FERCO gasifier in Burlington, VT.

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Project costs were not reported however, it was noted that the facility was shut down due to poor economics. The facility is currently used for Research and Development (R&D) for gas synthesis projects

Applying cogeneration or CHP will reduce the plant's electric efficiency but will increase the net overall efficiency since the thermal load is fully counted in the equation. A 25 MW power generation plant efficiency is shown in Figure 12. The base plant has an efficiency of 27% with a condensing steam turbine. As extraction is increased, the electric efficiency drops because the same fuel heat input generates less power. The net efficiency increases to a maximum of 75% which is equivalent to a backpressure steam turbine. The reduction in output is shown in Figure 13.

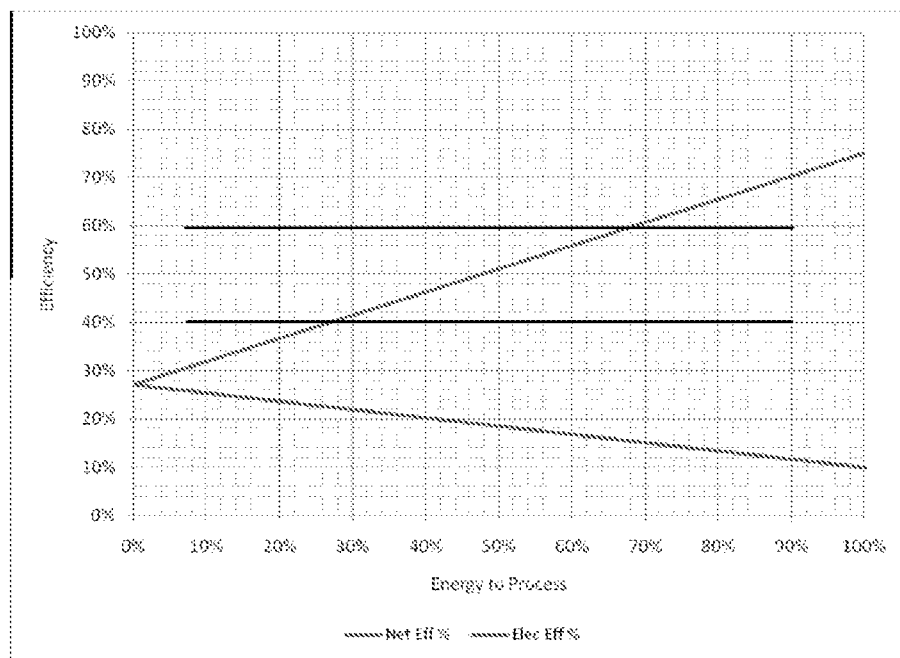


Figure 12

Effect of Cogeneration on Plant Efficiency

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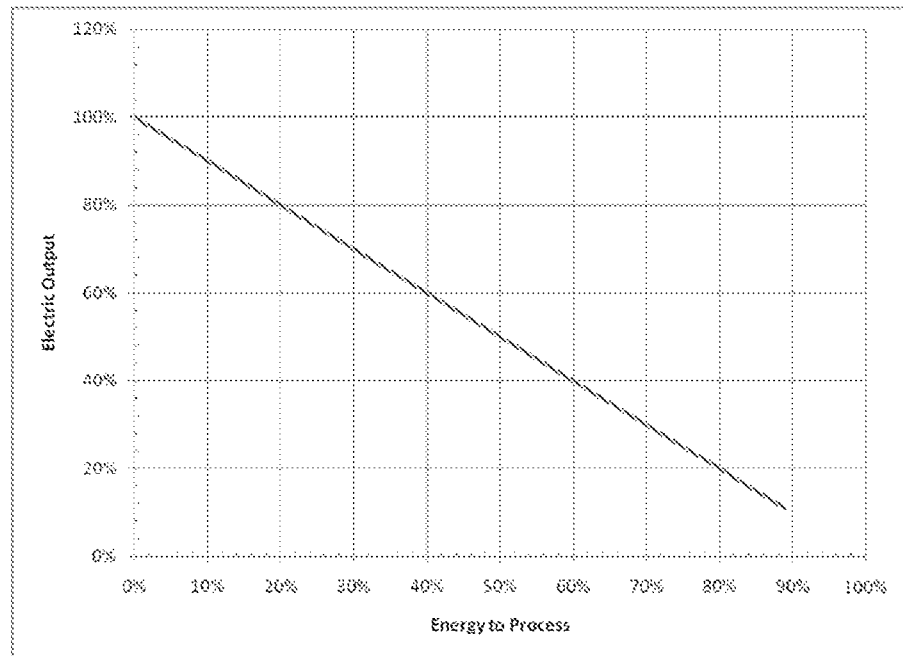


Figure 13

Effect of Extraction on Plant Output

Project Economics

An examination of plant economics and the effect of cogeneration (CHP) was undertaken to identify typical efficiencies and project economics that could be expected for biomass power and thermal energy production. The cases are simplified first year proforma calculations typically used for screening studies to determine viability of projects. The cases examined include:

1. New Biomass Generation – new 25 MW biomass plant with generation only.
2. New Biomass Cogeneration – 25 MW (condensing basis) with 150 psig extraction to an industrial process to meet a 60% net efficiency standard.
3. Small Biomass CHP – backpressure steam turbine generator
4. Thermal Only Plant – Heat Only
5. Small Biomass Thermal Plant – Heat only.

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Each plant is discussed below. The evaluation for each plant is based on the following assumptions:

- Market power rate is assumed to be \$100/MWh.
- Massachusetts REC pricing is assumed to be \$20/MWh
- Steam sales price assumed to be \$8.5/1000 lb.
- Fuel price is assumed to be \$30/Ton (AR)
- Boiler efficiency for the large plant is assumed to be 80%
- Boiler efficiency for the small plant is assumed to be 70%
- Plant auxiliary load is assumed to be 10%.
- Thermal heat for CHP is based on average Worcester, Massachusetts Heating Degree Days. The average annual thermal load is assumed to be 44.5% of the peak thermal load.
- Although absorption chilling can be used, no cooling using thermal plant output is assumed
- Plant availability is assumed to be 90%.
- Calculations are based on single year estimates with comparison before taxes, depreciation, amortization (EBITDA).
- The projects are assumed to be developed with 50% equity and 50% debt. The equity return is 15% over 15 years and the debt is assumed to be 8% over 15 years.

A summary is shown in Table 3.

Biomass Power Generating Case

The power generation case is based on a new 25 MW condensing Steam Turbine Generator plant similar to the base case. The project cost is \$4,000/kW or \$107 million. Project development is assumed to be 5% of the EPC cost for the project.

The EBITDA return for a new biomass power generation facility is -14.4%. This is driven by an annual cost of capital of \$16 million.

Biomass Cogeneration Facility

The same size facility as the base case is assumed to be developed adjacent to a large industrial steam customer. The steam turbine is an auto extraction steam turbine with an extraction port at 150 psig. An annual average steam load of 140,000 lb/h at 150 psig is exported from the facility. The plant electric efficiency drops to 14.8% but the net efficiency increases to 61.1%. The electric output from the plant is reduced to 13.9 MW from 26 MW. MASS RECs are available for the 15 MW.

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The EBITDA return is -20%

Small Biomass Combined Heat and Power

A small CHP plant is examined relative to the base case. The boiler size is reduced to 50,000 lb/h, 450 psig/600°F with a backpressure STG exhausting to process at 50 psig. The net output is 1.6 MW. The electric efficiency is 8.2% and the net efficiency is 39%.

The EBITDA return is -107.5%

Thermal Only Plant

The last case examined is a small thermal only plant. The boiler is the same size as the previous case. The plant efficiency is equal to 75%, equal to the boiler efficiency (not including the auxiliary electric load needed to run the plant). The EBITDA return for this project is -150%.

Small Thermal Plant (Heating Plant)

A small 5,000 lb/h, 10 psig heating plant is assumed for the last case. The steam price remains at \$8.50 per 1000 lb. Assuming that the boiler efficiency remains at 75%, The EBITDA is -250%.

Regulatory Risk

Project financing can be at risk in an uncertain regulatory environment. Government funding and programs can be uncertain or changed. Current federal and State incentives programs such as:

- Production Tax Credits
- BCAP
- Renewable Portfolio Standards (RPS)
- Accelerated depreciation
- Grants

dramatically affect the market and project development. In today's capital markets, there is scarce private capital beyond the developer's own seed capital, making it a difficult environment in which to start and fund a new project²⁰.

Comparisons are often made with European markets and biomass utilization. In addition to the differences described above, the absence of carbon credit/tax market is significant. To develop a European model one should expect:

1. Development of district heating/cooling market through required connection to an urban district energy system. Forcing heating users to connect to the district energy system and mandating equipment design for heating (and cooling).

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2. Equivalent power pricing. A table of power pricing in Europe is shown in Table 5 ²¹.
3. Carbon subsidies
4. Feed in Tariffs

The mix of renewables in Europe has dramatically shifted to biomass as shown in Table 2.

Table 2
European Union Renewable Energy Production

Ranking:	Resource:	2007:	2006:	2005:	Bar Graph:
1	Biomass	65,60 %	65,60 %	64,60 %	
2	Hydro energy	21,70 %	22,90 %	24,00 %	
3	Wind energy	6,60 %	5,50 %	5,30 %	
4	Geothermal energy	5,20 %	5,20 %	5,50 %	
5	Solar energy	1,00 %	0,80 %	0,70 %	

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Table 3 - Plant Economics Summary

Description	Units	New Condensing STG	New Extraction STG to Process	New Backpressure STG to Thermal	Thermal only	Small Thermal
Technical						
Plant Output	kW	25,957.38	15,971.92	1,815.82		
Average Annual Steam Demand				43.5%	44.5%	44.5%
Plant Export Steam Flow	lb/h		140,000.00	22,297.60	22,287.89	2,326.76
Steam Pressure	psig	150.00	150.00	50.00	50.00	10.00
Steam Temperature	°F	564.78	584.79	396.14	398.00	238.40
Steam Enthalpy	Btu/lb	1,308.72	1,308.72	1,179.54	1,232.54	1,160.30
Condensate Flow	lb/h		140,000.00	22,297.60	22,287.89	2,326.76
Condensate Temperature	°F	180.00	180.00	180.00	180.00	180.00
Condensate Enthalpy	Btu/lb	149.15	149.15	149.15	149.15	89.16
Net Energy to Process	MMBtu/h		162.20	22.97	24.15	2.39
Net Energy to Process	kW		47,536.17	6,730.88	7,076.73	689.70
Availability	%	90%	90%	90%	90%	90%
Plant Heat Rate	Btu/kWh	12,576.63	22,555.14	41,499.82		
Plant Efficiency	%	27.1%	15.1%	8.2%		
Net Plant Efficiency	%	27.1%	86.6%	42.5%	75.0%	75.0%
Heat Consumption	MMBtu/h	315.14	315.14	67.06	36.59	3.44
Heat Consumption	kW	92,358.04	92,358.04	19,852.22	10,724.66	1,009.61
Biomass Heating Value	Btu/lb	8,800	8,800	8,800	8,800	8,800
Moisture Content	%	40%	40%	40%	40%	40%
Fuel Heating Value	Btu/lb	5,280.00	5,280.00	5,280.00	5,280.00	5,280.00
Heat Consumption	Ton/h	29.84	29.84	6.35	3.47	0.39
Economics						
Project Cost	USD \$	106,228,986	106,228,988	22,500,000	15,500,000	2,000,000
Project Unit Cost	USD/kW	4,000				
Development (% of Capital)	%	5.0%	5.0%	5.0%	5.0%	5.0%
Development Cost	USD	5,311,438	5,311,438	1,125,000	875,000	100,000
IDC	%	1.5%	1.5%	1.5%	1.5%	1.5%
IDC	USD	1,578,622	1,578,622	364,375	212,625	31,600
Total Project	USD	106,820,087	106,820,087	23,979,375	14,387,625	2,131,500
Annual Debt	\$	6,365,668	6,365,668	1,428,989	857,394	127,021
Annual Equity	\$	9,661,934	9,661,934	2,168,947	1,301,368	192,735
Annual Capital Cost	\$	16,027,603	16,027,603	3,597,937	2,158,762	319,817
Staff		23	23	9	6	1
Average Salary	\$	50,000	50,000	50,000	50,000	50,000
Burdens & Benefits		1.30	1.30	1.30	1.30	1.30
Staff	\$	1,495,000	1,495,000	585,000	390,000	85,000
Maintenance & Spares	\$	1,002,300	1,002,300	225,000	135,000	20,000
Chemicals & Consumables	\$	200,460	200,460	45,000	27,000	4,000
Major Maintenance Fund	\$	2,505,749	2,505,749	582,500	337,500	50,000
Operations	USD \$	5,203,509	5,203,509	1,417,500	989,500	139,000
Boiler Annual Fuel Consumptio	MMBtu/h	2,484,554	2,484,554	528,671	288,508	27,160
Boiler Annual Fuel Consumptio	Ton/y	235,280	235,280	50,064	27,321	2,572
Boiler Fuel Cost (AR)	USD	25.00	25.00	25.00	25.00	25.00
Annual Fuel Cost	USD	5,881,993	5,881,993	1,251,588	688,020	64,299
Annual Cost	USD	27,113,104	27,113,104	6,267,025	3,731,282	523,115
Average Power Price	\$	100.00	100.00	100.00	100.00	100.00
REC	\$	20.00	20.00	20.00	20.00	20.00
Power Price	USD/MWh	120.00	120.00	120.00	120.00	120.00
Steam Price	USD/1000	8.50	8.50	8.50	8.50	8.50
Hours per Year	h	8,760.00	8,760.00	8,760.00	8,760.00	8,760.00
Annual Power Generated	MWh	197,553.28	110,154.65	12,739.11	-	-
Annual Steam Export	k lb/y	-	1,109,790.00	175,557.73	175,557.73	17,555.77
Annual Power Sales	\$	23,706,391.68	13,218,557.65	1,528,893.59	-	-
Annual Thermal Sales	\$	-	9,381,980.00	1,492,240.70	1,492,240.70	149,224.07
Annual Sales	\$	23,706,391.68	22,600,517.65	3,020,934.28	1,492,240.70	149,224.07
Annual Cost	\$	27,113,104.21	27,113,104.21	6,267,024.95	3,731,282.02	523,115.29
EBITDA	\$	(3,406,712.56)	(4,512,586.56)	(3,246,090.67)	(2,239,041.33)	(373,991.21)
Gross Margin		-14.4%	-20.0%	-107.5%	-150.0%	-250.6%

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Table 4

Electricity		Gas	
€ per kWh electricity Consumption: 25,000 kWh/year (2.7 TWh of electricity)		€ per kWh gas Consumption: 12,500 kWh/year (1.35 TWh of gas)	
Average amount in electricity consumption of gas for domestic consumers Ind. energy taxes & VAT Effective November '09		Average amount in gas consumption of gas for domestic consumers Ind. energy taxes & VAT Effective November '09	
Austria	€ 0.171	Austria	€ 0.147
Belgium	€ 0.172	Belgium	€ 0.152
Bulgaria	€ 0.093	Bulgaria	€ 0.077
Cyprus	€ 0.144	Cyprus	€ 0.142
Czech Rep.	€ 0.116	Czech Rep.	€ 0.087
Denmark	€ 0.268	Denmark	€ 0.232
Estonia	€ 0.091	Estonia	€ 0.076
Finland	€ 0.128	Finland	€ 0.107
France	€ 0.138	France	€ 0.117
Germany	€ 0.211	Germany	€ 0.204
Greece	€ 0.089	Greece	€ 0.089
Hungary	€ 0.148	Hungary	€ 0.146
Ireland	€ 0.184	Ireland	€ 0.153
Italy	€ 0.260	Italy	€ 0.224
Latvia	€ 0.088	Latvia	€ 0.077
Lithuania	€ 0.091	Lithuania	€ 0.079
Luxembourg	€ 0.189	Luxembourg	€ 0.182
Malta	€ 0.105	Malta	€ 0.120
Netherlands	€ 0.241	Netherlands	€ 0.240
Poland	€ 0.140	Poland	€ 0.127
Portugal	€ 0.172	Portugal	€ 0.143
Romania	€ 0.130	Romania	€ 0.114
Slovakia	€ 0.179	Slovakia	€ 0.136
Slovenia	€ 0.132	Slovenia	€ 0.113
Spain	€ 0.143	Spain	€ 0.117
Austria	€ 0.071	Austria	€ 0.059
Belgium	€ 0.061	Belgium	€ 0.044
Bulgaria	€ 0.028	Bulgaria	€ 0.034
Cyprus	NODATA	Cyprus	NODATA
Czech Rep.	€ 0.041	Czech Rep.	€ 0.036
Denmark	€ 0.117	Denmark	€ 0.105
Estonia	€ 0.028	Estonia	€ 0.027
Finland	NODATA	Finland	NODATA
France	€ 0.068	France	€ 0.051
Germany	€ 0.085	Germany	€ 0.066
Greece	NODATA	Greece	NODATA
Hungary	€ 0.042	Hungary	€ 0.040
Ireland	€ 0.107	Ireland	€ 0.107
Italy	€ 0.074	Italy	€ 0.069
Latvia	€ 0.030	Latvia	€ 0.028
Lithuania	€ 0.032	Lithuania	€ 0.028
Luxembourg	€ 0.061	Luxembourg	€ 0.040
Malta	NODATA	Malta	NODATA
Netherlands	€ 0.047	Netherlands	€ 0.046
Poland	€ 0.048	Poland	€ 0.042
Portugal	€ 0.068	Portugal	€ 0.052
Romania	€ 0.036	Romania	€ 0.035
Slovakia	€ 0.046	Slovakia	€ 0.044
Slovenia	€ 0.055	Slovenia	€ 0.051
Spain	€ 0.063	Spain	€ 0.053

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Conclusions

Biomass power generation is a dispatchable power supply that uses waste wood to generate power. Development of any efficiency standard for Renewable Power Credits should be carefully evaluated in light of existing technology and available power markets.

The proposed 40% minimum efficiency limit, which allows for 50% of the REC, is well above the efficiency of any of the merchant biomass based power plants currently in operation in the regional market. The only possible method of achieving the proposed efficiency standards is by installing large industrial steam hosts, which is highly unlikely. Finding a steam host, building an industrial facility, and altering the biomass power plant to deliver steam is not a reasonable proposition. It is not expected that any of the current facilities could be upgraded in this manner, thus leading to the removal from the market of the current biomass renewable fleet currently part of the Massachusetts renewable portfolio.

For new facilities, the proposed requirement is equally unrealistic. The proposed 60% minimum efficiency limit for 100% RPS qualified generation does not appear to be based on current commercialized technologies. A 60% efficiency criterion is outside of the published limits of systems that are in pilot or research scale. Advanced biomass power generation technology will not meet even the minimum 40% criteria to receive RECs. The net effect is that the proposed efficiency requirements will eliminate biomass as a renewable energy source for Massachusetts.

A 60% efficiency requirement can only be achieved by developing new cogeneration. As the thermal load is increased to meet the net efficiency requirement, the electrical output is reduced, lowering the electric power available to obtain REC's. The reduced incentive will adversely impact project economics. Moreover, such opportunities are unlikely to be pursued, given the challenges associated with siting large biomass facilities adjacent to industrial locations and issues with fuel transport in local communities, and the limited ability to find credit worthy steam hosts.

That leaves smaller CHP opportunities, which have financial returns that are not attractive, and thermal-only applications that are both unattractive and do not generate electricity under the RPS.

In summary, using a high efficiency standard for biomass power production is not reasonable, lacks economic viability, and assumes European-style markets and subsidies that are not found anywhere in the United States. The result of the proposed efficiency requirement will be to eliminate biomass as a ready, dispatchable, renewable energy power resource.

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- ² http://www.law.cornell.edu/uscode/html/uscode16/usc_sup_01_16_10_46.html
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- ⁴ The Biomass Energy Foundation Press, Nov 2002, 3rd edition, T. Reed, Fig III-4
- ⁵ <http://www.nexterra.ca/>
- ⁶ Private conversation with vendor representative as to the state of commercialization with respect to biomass gasification/internal combustion based generation equipment.
- ⁷ http://www.epa.gov/chp/documents/biomass_chp_catalog.pdf
- ⁸ <http://www.nh.gov/oep/programs/energy/documents/nhbio-oilopportunityanalysis.pdf>
- ⁹ <http://www.dynamotive.com/>
- ¹⁰ <http://www.mainebioproducts.com>
- ¹¹ <http://www.whispergen.com/>
- ¹² <http://www.turboden.eu/en/home/index.php>
- ¹³ <http://entropicenergy.com/>
- ¹⁴ <http://www.biomasscenter.org/pdfs/Wood-Chip-Heating-Guide.pdf>
- ¹⁵ <http://www.ferc.gov/industries/electric/gen-info/qual-fac/benefits.asp>
- ¹⁶ Form EIA-860, "Annual Electric Generator Report," - Generator (Existing) File, 2008 (<http://www.eia.doe.gov/cneat/electricity/page/eia860.html>)
- ¹⁷ Private correspondence
- ¹⁸ G. Wiltsee, *Lessons Learned from existing Biomass Power Plants*, Appel Consultants, Inc. NREL Contract no. DE-AC36-99-GO10337
- ¹⁹ Stahl, et al, *biomass IGCC at Varnamo, Sweden – Past and Future*, GCEP Energy Workshop, April 2004. http://gcep.stanford.edu/pdfs/energy_workshops_04_04/biomass_stahl.pdf
- ²⁰ Sue Wyka, *Biomass Project Financing Solutions in Today's Difficult Capital Markets*, Biomass Magazine, June 2009
- ²¹ Europe's Energy Portal, <http://www.energy.eu/#Domestic>

CLAIMS:

1. A method of generating energy comprising:
reducing the recalcitrance of a biomass feedstock formed from a lignocellulosic
5 material by treating the biomass feedstock with a radiation dose of between 10 Mrad and
about 100 Mrad;
saccharifying the biomass feedstock to form a saccharified biomass material;
wherein the saccharified biomass material comprises inorganic solids; and
combusting the saccharified biomass material and inorganic solids to produce
10 energy.
2. The method of claim 1, wherein the saccharified biomass material includes
cells.
- 15 3. The method of claim 2, wherein the cells are selected from the group
consisting of yeast cells, bacterial cells, fungal cells and mixtures thereof.
4. The method of any of the above claims, wherein the saccharified biomass
material includes protein material.
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5. The method of claim 4, wherein the protein material is an enzyme material.
6. The method of any one of the above claims, wherein the saccharified material
includes denatured enzyme material.
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7. The method of any one of the above claims, wherein the saccharified biomass
material comprises lignocellulosic residue from lignocellulosic material that has been
treated to reduce its recalcitrance prior to saccharification.
- 30 8. The method of claim 7, wherein the lignocellulosic material has been treated
with accelerated electrons to reduce its recalcitrance.

9. The method of claim 8, wherein the electrons have an average energy between about 0.3 MeV and about 5 MeV, or between about 0.5 MeV and about 3.5 MeV, or between about 0.8 MeV and about 2 MeV.

5 10. The method of claim 9, wherein the lignocellulosic biomass has been treated to a total dose between about 15 Mrad and about 50 Mrad, or between about 20 Mrad and about 45 Mrad, or between about 25 Mrad and about 40 Mrad.

10 11. The method of claim 1, wherein the inorganic solids is selected from the group consisting of diatomaceous earth, celite, silica, pumice, perlite, alumina, zeolites, sand and mixtures thereof.

12. The method of any one of the above claims, wherein the saccharified biomass material includes less than 60 percent moisture, or less than 50 percent moisture, or less
15 than 45 percent moisture, or less than 40 percent moisture, or less than 30 percent moisture.

13. The method of any one of the above claims, wherein saccharified biomass material includes less than 5 percent ash after combustion.

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14. The method of any one of the above claims, wherein the saccharified biomass material includes less than 0.5 percent sulfur.

15. The method of any one of the above claims, wherein the saccharified biomass
25 material includes less than 35 percent by weight carbohydrates on a dry basis, or less than 30 percent by weight carbohydrates on a dry basis, or less than 25 percent by weight carbohydrates on a dry basis, or less than 20 percent by weight carbohydrates on a dry basis, or less than 10 percent by weight carbohydrates on a dry basis.

30 16. The method of any one of the above claims, wherein the energy is in the form of heat or electrical energy.

17. The method of any one of the above claims, wherein during combustion a boiler is utilized.

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18. The method of claim 17, wherein the boiler is selected from the group consisting of a stoker grate boiler, a fluidized bed boiler and a co-fired boiler.

19. The method of any of one of the above claims, wherein during combustion, a
5 gasifier is utilized.

20. The method of claim 19, wherein the gasifier is a fixed bed or a fluidized bed gasifier.

10 21. The method of any one of the above claims, wherein the saccharified biomass is collected utilizing a rotary drum filter prior to combustion.

22. The method of any one of the above claims, wherein the saccharified biomass is collected utilizing a centrifuge prior to combustion.

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