United States
Department of
Agriculture

Forest Service

Pacific Northwest
Research Station

General Technical Report
PNW-GTR-867

August 2012

Cofiring Biomass and Coal for Fossil Fuel Reduction and Other Benefits—Status of North American Facilities in 2010

David Nicholls and John Zerbe

Authors

David Nicholls is a forest products technologist, Alaska Wood Utilization and Development Center, 204 Siginaka Way, Sitka, AK 99835; and **John Zerbe** is a volunteer, Forest Products Laboratory, One Gifford Pinchot Dr., Madison, WI 53726.

Cover photo of Seattle by Tom Iraci.

Abstract

Nicholls, David; Zerbe, John. 2012. Cofiring biomass and coal for fossil fuel reduction and other benefits–Status of North American facilities in 2010. Gen. Tech. Rep. PNW-GTR-867. Portland, OR: U.S. Department of Agriculture, Forest Service, Pacific Northwest Research Station. 22 p.

Cofiring of biomass and coal at electrical generation facilities is gaining in importance as a means of reducing fossil fuel consumption, and more than 40 facilities in the United States have conducted test burns. Given the large size of many coal plants, cofiring at even low rates has the potential to utilize relatively large volumes of biomass. This could have important forest management implications if harvest residues or salvage timber are supplied to coal plants. Other feedstocks suitable for cofiring include wood products manufacturing residues, woody municipal wastes, agricultural residues, short-rotation intensive culture forests, or hazard fuel removals. Cofiring at low rates can often be done with minimal changes to plant handling and processing equipment, requiring little capital investment. Cofiring at higher rates can involve repowering entire burners to burn biomass in place of coal, or in some cases, repowering entire powerplants. Our research evaluates the current status of biomass cofiring in North America, identifying current trends and success stories, types of biomass used, coal plant sizes, and primary cofiring regions. We also identify potential barriers to cofiring. Results are presented for more than a dozen plants that are currently cofiring or have recently announced plans to cofire.

Keywords: Cofiring, coal, biomass, fossil fuel, harvest residues.

Contents

Introduction

Cofiring of biomass and coal presents a significant opportunity to address recent social, economic, and environmental incentives to reduce fossil fuel consumption for power generation in the United States. Coal plants are among the largest point source producers of nonrenewable carbon dioxide (CO_2), and coal remains a significant energy source in the United States, with more than 1.1 billion tons consumed in 2008. More than 92 percent of this was used by the electric power sector (US DOE-EIA 2009).

One of the most easily implemented biomass (material derived from plant matter) energy technologies is cofiring with coal in existing coal-fired boilers (US DOE 2004). Biomass can provide numerous benefits when used as a fuel to supplement coal, including potentially lower fuel costs, lower landfill disposal costs, and reduce emission of sulfur dioxide (SO_2) and oxides of nitrogen (NOx) (US DOE 2004). Other environmental benefits of cofiring may be more difficult to evaluate. The subject of carbon neutrality and biomass has become quite controversial lately, with some studies supporting the conclusion that cofiring results in net life-cycle greenhouse gas (GHG) reductions versus burning coal alone. For example, Mann and Spath (2001) estimated that cofiring rates of 5 and 15 percent would reduce equivalent CO_2 emissions from burning coal alone by 5.4 and 18.2 percent, respectively. Zhang et al. (2010) found that life-cycle GHG emissions (measured in grams of CO_2 per kilowatt [kW]-hour) for wood pellet combustion were less than 10 percent of those for two coal types used in Canada. In contrast, other studies suggest no net cumulative emission reductions by 2050 if biomass were to replace coal in powerplants (Manomet Center for Conservation Science 2010), and suggest that in some cases, biomass fuels can be more carbon positive (produce more carbon) than fossil fuels (Johnson 2009). Clearly, the issue of atmospheric carbon and implications on forest biomass is controversial, with yet unanswered questions. Additional research could help provide quantitative answers to these questions, especially considering the global dimensions associated with forest management, atmospheric emissions, and power generation to meet increased worldwide energy demands.

Many U.S. coal facilities have at least performed cofiring trials, and cofiring is expected to be important for the foreseeable future.

Despite this controversy, biomass cofiring has been a proven opportunity for coal facilities for more than a decade (Hughes 2000). Many U.S. coal facilities have at least performed cofiring trials, and cofiring is expected to be important for the foreseeable future. Further, equitably valuing the entire range of benefits of cofiring biomass with coal could further help to frame this debate, because numerous "externalities" and impacts of coal burning have not yet been valued (Faiij et al. 1998), including:

- Reductions in sulfur emissions (vs. burning coal only)
- Reductions in NOx emissions under most combustion scenarios
- Reductions in mercury emissions (Mentz et al. 2005)
- Reductions of landfill material (when cofiring municipal waste, construction debris, or other biomass material that would otherwise be landfilled, or when larger amounts of ash from coal must be landfilled for disposal)

An important consideration for managers who are considering wood-coal cofiring is whether to cofire at low rates (with minimal capital investment) versus cofiring at higher rates (with greater capital investment).

Many coal plants can be "re-tooled" for biomass cofiring at a very reasonable cost. An important consideration for managers who are considering wood-coal cofiring is whether to cofire at low rates (with minimal capital investment) versus cofiring at higher rates (with greater capital investment). At low cofiring rates, expenses can be limited to minor mixing and blending of wood fuel with coal, often performed using a front-end loader. Cyclone boilers also offer low-cost opportunities for cofiring, typically in the range of $50 per kW of installed biomass capacity (NREL 2000). Higher cofiring rates often require a relatively modest investment of typically $50 to $300 per kW of installed biomass capacity (Baxter and Koppejan, n.d.), and in pulverized coal (PC) systems this is typically $150 to $300 per kW (NREL 2000).

Cofiring at high rates (e.g., 10 percent of energy value) often involves separate wood fuel storage, handling, and injection systems. In this case, the capital and operating costs of retrofitting must be weighed against the expected benefits (De and Assadi 2009). In the case of larger coal facilities, a 10-percent cofiring rate (based on energy value) can be substantial. For example, the Drax facility in England expects to cofire 10 percent of a total coal capacity of 4,000 megawatt (MW) (resulting in 400 MW of energy from biomass) (Saimbi and Hart 2010). Some practical considerations for cofiring at high rates and repowering with biomass include the need for larger fuel storage areas, the potential need for wood fuel drying systems, and more powerful fans owing to the relatively low bulk density of wood fuels.

Three general techniques are most often used when cofiring biomass and coal (Tillman 2000):

- Blend biomass and coal in the fuel handling system (then feed into boiler)
- Prepare biomass separately from coal, then inject into boiler (with no impact on coal delivery)
- Gasify biomass, creating producer gas that is then combusted in a boiler to provide steam or hot water directly or used with an integrated gasification combined cycle (IGCC) system.

Worldwide, nearly 200 coal facilities have conducted test burns with biomass (IEA 2010). In the United States, more than 40 coal plants have conducted test burns. Numerous fuel types have been evaluated including wood chips, sawdust, switchgrass, and urban wood wastes (IEA 2010). However many of these test burns occurred at least 10 years ago, and were for limited amounts of biomass with short-duration test burns. Because many coal plants are aging and near replacement, cofiring with biomass could be an excellent "bridge" strategy to quickly reduce GHGs for a given facility whether or not coal would be used in the future. Further, the large size of many coal facilities could result in relatively large volumes of biomass utilization even at relatively low rates of cofiring. For example, it has been estimated that if all coal plants in the state of Colorado cofired at even a rate of 1 percent energy value, then 53 MW of wood energy capacity would be added (about the size of a large wood energy installation) (Sourcewatch 2010).

Because many coal plants are aging and near replacement, cofiring with biomass could be an excellent "bridge" strategy to quickly reduce GHGs for a given facility whether or not coal would be used in the future.

Salvage biomass material, including salvage timber from fires or insect infestation, represents a significant resource for cofiring. However, important considerations would be the economics of transporting material to coal plants as well as the need to include merchantable timber (for higher value nonfuel use) as part of salvage operations. With 33 coal plants and significant acreages of beetle-killed timber, Colorado could be well-positioned to pursue cofiring opportunities. Use of salvage timber could become an important bridge strategy for coal plants as they pursue other, longer term fuel supplies.

Some large-scale regions are proposing wholesale shifts away from coal in favor of other fuels, e.g., the province of Ontario, Canada (see case study 3). The Netherlands is also making wholesale shifts toward cofiring. Here, cofiring has been conducted in at least six locations, and fuel sources have included wood pellets, demolition waste, sewage sludge, and chicken manure (vanRee et al. 2000). Also in Europe, several circulating fluidized bed (CFB) combustors have been established, representing opportunities for cofiring coal with numerous fuel types and particle sizes (Zabetta et al. 2009). These and other developments in Europe and Canada can provide examples for the United States to emulate.

Several technical challenges associated with cofiring have been identified, and work is ongoing to identify practical solutions. For example, pulverizing wood particles for use in PC burners can pose some technical challenges (Prinzing and Hunt 1998). Other operational challenges can include (Baxter and Koppejan 2004):

- Stable, high-quality fuel supplies
- Fuel handling and storage
- Potential increases in corrosion
- Decreases in overall efficiency
- Ash deposition and ash marketing issues
- Control of moisture content
- Impacts on selective catalytic reduction (SCR) performance
- Overall economics

Objectives

Three objectives of this report are to:

Review the status of cofiring biomass and coal in North America, determining how many plants are still cofiring today on an ongoing basis; includes woody biomass and other cellulosic materials.

Determine which facilities are actually cofiring today (or have concrete plans for cofiring).

Include a discussion about cofiring trends in North America and future opportunities to use woody biomass.

Past Cofiring (Pre-2000)

Numerous test burns of coal and biomass were conducted in the 1990s as part of collaboration between the Electric Power Research Institute and the U.S. Department of Energy.

Early test burns with wood and coal (mostly in the 1990s) evaluated a variety of feedstocks, including wood chips, tires, urban wood wastes, agricultural residues, and others (tables 1, 2, and 3). They also considered several coal combustion systems, including stokers, PC, and cyclone burners. Most of these tests were short-term trials only, often lasting just a few days or weeks. Further, most of these tests considered relatively low cofiring rates. Results of these tests indicated the general feasibility of cofiring with wood and coal at low rates, but also revealed some challenges. For example, pulverizing wood particles for use in PC burners can pose some technical problems (Prinzing and Hunt 1998). Other studies have found that successful cofiring in PC systems requires wood particle sizes of 1/16 inch or smaller (Gold and Tillman 1996). Numerous test burns of coal and biomass were conducted in the 1990s as part of collaboration between the Electric Power Research Institute (EPRI) and the U.S. Department of Energy (Tillman 2001). These tests investigated the feasibility of cofiring with a number of different feedstocks under various operating conditions and different coal burning technologies.

Table 1—Test burns at selected U.S. powerplants started prior to 2001

Location	Name	Boiler type	Output	Primary fuel	Cofired fuels	Cofire duration
Gadsden, Alabama	Gadsden Steam Plant No. 2	Tangentially fired burner	60 MW	Pulverized coal	Switchgrass	4 weeks
Madison, Wisconsin	Blount Street Station	Wall-fired burner	100 MW	Pulverized coal	Switchgrass	—
Ashland, Wisconsin	Bay Front Station	Grate	44 MW	Coal	Wood, shredded rubber, railroad ties	
Chesterton, Indiana	Bailey Generating Station No. 7	Cyclone burner	160 MW	Pulverized coal	Urban wood waste, petroleum coke	300 hours (57 test burns)
Dresden, New York	Dunkirk Steam Station No. 1	Tangentially fired burner	90 MW	Pulverized coal	Willow wood	6 months
Dresden, New York	Greenridge Generating Station No. 6	Tangentially fired burner	108 MW	Pulverized coal	Wood chips	—
Lake Michigan, Indiana	Michigan City Generating Station No. 12	Cyclone	469 MW	Pulverized coal	Urban wood waste	6 tests (over 5 days)
Memphis, Tennessee	T.H. Allen Plant	Cyclone	272 MW	Pulverized coal	Sawdust	24 tests (each 3 to 6 hours long)
Johnstown, Pennsylvania	Shawville Generating Station No. 2	Wall-fired	138 MW	Pulverized coal	Ground wood	7 days (3 to 4 hours each)
Tampa, Florida	Gannon Generating Station	Cyclone	165 MW	Pulverized coal	Paper pellets	21 days
Tuscumbia, Alabama	Colbert Fossil Plant No. 1	Front wall fired	182 MW	Pulverized coal	Sawdust	—
Pittsburgh, Pennsylvania	Natl. Inst. Occ. Safety & Health	Stoker grate	55,000 lb per hr	Coal	Wood chips	—
Pittsburgh, Pennsylvania	Pittsburgh. Brewing Co	Travelling grate	42,000 lb per hr	Coal	Wood chips	16 test burns (up to 16 hours each)
Pittsburgh, Pennsylvania	Seward Generating Station No. 12	Wall fired	32 MW	Pulverized coal	Sawdust	—
Prewitt, New Mexico	Escalante Generating Station No. 1	Tangentially fired	250 MW	Pulverized coal	Waste paper sludge	2-year duration
Stillwater, Minnesota	King Generating Station No. 1	Cyclone	560 MW	Pulverized coal	Kiln-dried wood, petroleum coke	2-year duration
Tacoma, Washington	City of Tacoma Steam Plant No. 2	Bubbling fluidized bed	18 MW	Coal	Wood, refuse-derived fuel	—

— = No information available.
Source: International Energy Administration-Task 32 [2010]. Cofiring database http://www.ieabcc.nl/database/cofiring.php.

Other cofiring tests of this same era include:

Seward Station (Pennsylvania). This study evaluated wood sawdust cofiring with separate injection from coal in wall-fired PC systems. Wood was cofired at up to 7 percent energy value (15 percent by mass), with only minor decreases in boiler efficiency (Battista et al. 2000). Capital costs for cofiring with separate injection were held to less than $200 per kW (energy from wood).

Table 2—Cofiring tests at full-scale utility boilers (pre-2001)

Location	Name	Boiler type	Primary fuel	Cofired fuels	Cofire date
Minnesota	Northern States Power	Cyclone boiler	Coal	Sander dust	Started in 1987
South Carolina	Santee Cooper Electric	Pulverized coal boiler	Pulverized coal	Forest debris from Hurricane Hugo	1990
Georgia	Plant Hammond	Pulverized coal boiler	Pulverized coal	Waste wood	1992
Tennessee Valley Authority	Kingston plant	Tangentially fired pulverized coal boiler	Pulverized coal	Wood (low percentage)	1993, 1994
Tennessee Valley Authority	Colbert plant	Wall-fired pulverized coal boiler	Pulverized coal	Wood (low percentage)	1992
Tennessee Valley Authority		Cyclone boiler	Coal	Wood (up to 20 percent by mass)	1995
Savannah Electric		Pulverized coal boiler	Pulverized coal boiler	Wood (high percentage)	1993
New York State	NYSEG	Pulverized coal boiler	Pulverized coal boiler	Wood (10 percent by heat)	1994
Madison Gas and Electric	University of Wisconsin	Wall-fired, grate-equipped, pulverized coal boiler	Pulverized coal boiler	Switchgrass	1996
Tacoma, Washington	Tacoma Public Utilities	Fluidized bed boiler	Coal	Biomass	Started in 1991

Source: Sami et al. 2001.

Bailly Station (Indiana). This cofiring work included test burns of "triburn blends" of biomass, petroleum coke, and coal. Triburn cofiring resulted in (1) increased boiler efficiency, (2) reduced fuel costs, and (3) reduced emissions of NOx, mercury, and CO_2 (Hus and Tillman 2000). Here, up to 30 percent of coal was replaced with petroleum coke and wood waste.

Shawville Station (Pennsylvania). This test fire program evaluated the effect of low-percentage wood cofiring (up to 3 percent by weight) on operating characteristics of 138-MW and 190-MW PC boilers. Three percent wood cofiring resulted in negative impacts in pulverizing, which led to reductions in boiler capacity for wall-fired and tangentially fired systems (Hunt et al. 1997). Alternatively, a separate injection system could be used for wood (bypassing the coal pulverizer).

Gadsden Station (Alabama). This facility has evaluated switchgrass cofiring as part of a comprehensive evaluation of farm production issues, pilot-scale cofiring, and full-scale firing (Boylan et al. 2000). This research found that, even at cofiring rates of 5 percent switchgrass by mass in PC boilers, separate injection from coal is preferred. Other research at the Gadsden Station has considered cofiring coal with green wood chips. Test parameters included particle size of wood chip and the presence of pine foliage in the fuel mixture (Boylan et al., n.d.; Boylan 1996).

Table 3—United States powerplants cofiring with biomass (2001)

Facility	Company	City/county	State	Capacity	Heat input from biomass
				- - - *Megawatt* - - -	
6th Street	Alliant Energy	Cedar Rapids	Iowa	85	7.7
Bay Front	Xcel Energy	Ashland	Wisconsin	76	40.3
Colbert	Tenn. Valley Auth.	Tuscumbia	Alabama	190	1.5
Gadsden 2	Alabama Power Co.	Gadsden	Alabama	70	<1.0
Greenridge	AES	Dresden	New York	161	6.8
C.D. McIntosh, Jr.	City of Lakeland	Polk	Florida	350	<1.0
Tacoma Steam Plant	Tacoma Public Utilities	Tacoma	Washington	35	44.0
Willow Island 2	Allegheny Power	Pleasants	West Virginia	188	1.2
Yates 6 and 7	Georgia Power	Newnan	Georgia	150	<1.0

Source: Haq 2002.

Tennessee Valley Authority (Allen, Kingston, and Colbert Stations). Cofiring tests were conducted at three coal facilities owned by the Tennessee Valley Authority. It was found that cofiring at 10 to 15 percent heat input for PC systems would require separate wood preparation systems and wood fuel burners (Gold and Tillman 1996).

Dunkirk Station (New York). A short-rotation willow production model has been developed in New York, having a goal of providing biomass feedstock for cofiring. Heller et al. (2004) found that when cofiring 10 percent willow, the system net energy ratio increases by 8.9 percent while the net global warming potential decreases by 7 to 10 percent. Net SO_2 emissions are reduced by 9.5 percent. Tharakan et al. (2005) stressed the importance of biomass tax credits, given that the production cost of willow feedstock is more than twice that of coal.

Blount St. Station (Wisconsin). This trial consisted of cofiring switchgrass at a 50-MW coal burner in Madison, Wisconsin. Cofiring levels varied between 4.3 and 10.2 percent heat input of switchgrass, resulting in decreases in combustion efficiency of only about 1 percent (versus 100 percent coal) (Tillman 2001). An important benefit of switchgrass cofiring is the potential decrease in NOx emissions, which were reduced about 31 percent owing to switchgrass cofiring (Aerts and Ragland 1997).

Bellefield Boiler (Pennsylvania). Urban wood waste (construction debris) was cofired with coal in an underfeed stoker boiler using blends of 20 to 40 percent wood by volume (Cobb et al. 2004). The wood component consisted mainly of pallets, trim ends of framing lumber, trim ends of trusses, and minor amounts of plywood and particleboard. Combustion efficiency decreased only slightly even with 40 percent wood volume. However some assistance was needed to help maintain flow of the 40 percent blend so that wood was not unevenly distributed on the grate. Also an increase in slagging was noticed with the 40 percent wood blend (Cobb et al. 2004).

Northern Indiana Public Service Company (Indiana). Cofiring in this cyclone burner system was done with 1,000 tons of urban wood waste and kiln-dried wood waste (sawdust). Wood was screened to ½ inch in size, then blended with coal for cofiring at 6.5 percent energy value (Tillman 2001). Cofiring with wood resulted in a 9.5 percent decrease in NOx emissions and only minor reductions in boiler efficiency (approx. 0.5 percent).

Case Study Briefs

Case 1: Coal Plant Repowering for Biomass (Portsmouth, New Hampshire)

At the Schiller Generating Station in New Hampshire, a 50-MW coal burner has been retrofitted to burn entirely wood in a circulating fluidized bed (CFB) boiler, while two other 50-MW units still burn coal. The biomass plant plans to earn 350,000 renewable energy credits (RECs) annually, which could be sold to power companies in Connecticut and Massachusetts. Sale of these credits could be worth an estimated $15 million per year, helping to shorten the payback period of the repowering project, which cost an estimated $75 million (Peltier 2007). The new CFB boiler fueled by wood emits about 75 percent less NOx, 98 percent less SO_2, and 90 percent less mercury than the coal boiler used previously (Peltier 2007). Given the flexibility of this CFB system, coal can be burned when needed. However the primary fuel source is to be 400,000 tons of whole-tree chips and clean, low-grade wood. The wood energy facility was commissioned in December 2006.

Case 2: Coal Plant Repowering for Biomass (Shadyside, Ohio)

The Burger powerplant in Shadyside, Ohio, was planning to cofire wood pellets and agricultural biomass pellets with coal in two 156-MW units. This facility was expected to be “biomass-ready” by late 2012, with retrofits costing $200 million, and could burn biomass to produce up to 312 MW. Cofiring with up to 20 percent low-sulfur coal might also have been allowed (Renewable Energy World 2009). Eventually the plant was to be operated as a closed-loop bioenergy facility, with biomass fuel being obtained from dedicated energy plantations (Holly 2009). Under one scenario, woody and agricultural biomass would be pressed into cubes, which would later be pulverized for cofiring with coal. After much preliminary work, including obtaining construction permits, this project was cancelled by power producer First Energy because of falling prices for electricity (Cartledge 2010). Instead, plans call for permanently shutting down two of the coal units by the end of 2010.

Case 3: Coal Plant Repowering for Biomass (Ontario, Canada)

The Ontario, Canada, provincial government is planning to phase out all coal-based electrical generation from Ontario Power Generation (OPG) by the end of 2014 (Marshall et al. 2010). Ontario Power Generation operates five fossil fuel power stations (total installed capacity of 8,177 MW), of which four are coal powered. Although provincial mandates are expected to motivate some conversions to natural gas (Murray 2010), OPG is also giving serious consideration to wood pellets for replacing substantial portions of their coal load. In 2008, test burns were conducted at the Atikokan Generating Station to evaluate the feasibility of powering a 227-MW coal (lignite) boiler with wood pellets (Marshall et al. 2010). As of September 2010, negotiations were underway for purchasing renewable power generated from the Atikokan facility. When repowering is completed, close to 99,000 tons of wood pellets per year will be required (Austin 2010).

The Ontario, Canada, provincial government is planning to phase out all coal-based electrical generation from Ontario Power Generation by the end of 2014.

Other facilities (i.e., the Nanticoke Station) have begun plant preparations for firing with biomass, including a 50-MW injection system for introducing agricultural and woody biomass fuels into commercial-scale systems. Future work by OPG for increased biomass use includes:

- Evaluating fuel supplies (for agriculture residues and woody biomass)
- Evaluating transportation logistics
- Evaluating unloading and fuel storage requirements (as well as safety measures)
- Analyzing complete GHG life cycle of biomass fuels versus coal

The Ontario powerplants under consideration for phasing out coal are:

- Atikokan Station (211 MW)
- Lambton Station (1,920 MW)
- Nanticoke Station (3,640 MW)
- Lakeview Station (1,140 MW)
- Thunder Bay Station (310 MW) planned conversion from coal to natural gas

Case 4: High-Rate Cofiring (Colorado Springs, Colorado)

Colorado Springs Utility is planning to continuously blend about 15 percent biomass (energy value) with 85 percent coal in one of their burners, utilizing more than 100,000 tons of wood per year. Cofiring will occur within a 140-MW capacity coal burner, where nearly 20-MW of energy will be from wood. The wood is expected to come from a pellet plant in Colorado where a "microchip" product (approx. 1/2 inch by 5/8 inch maximum dimension) will be produced. After delivery to the Colorado Springs coal facility, wood will be further processed in a hammermill grinder to a maximum dimension of about 1/16 inch, then mixed with the PC (Meikle 2010).

A potentially significant advantage of burning low-moisture beetle-killed wood is that it is already close to the British Thermal Unit (BTU) value of some low-rank coals. For example, coal mined in Wyoming has an average of only 8,600 BTU per pound, only somewhat greater than that expected from the beetle-killed wood (Sourcewatch 2010).

The plant renovations needed to receive, store, process and inject biomass separately from coal at the Colorado Springs plant are expected to cost about $10 million (Anon. 2010). An important aspect of this project is the separate fuel injection systems needed for coal and wood. As of June 2010, design and engineering plans have been finalized and a contractor chosen for this work (Meikle 2010).

Although the Colorado Springs project is expected to allow high cofiring rates, lower cofiring rates of biomass are possible as well. These projects typically do not require expensive capital improvements because the wood and coal can be mixed together and burned through a common injection system. Typically, costs for low percentage cofiring range from about $50 to $300 per installed kilowatt of biomass (National Renewable Energy Lab 1999).

There are many coal-burning plants in the northern Rocky Mountain region, some of which could be within economical transportation distances of beetle-killed wood. For example, Colorado has 33 coal-fired powerplants (at 14 locations) totaling more than 5,300 MW of generating capacity (Sourcewatch 2010). However, other wood fuel sources could be available along Colorado's Front Range to supplement beetle-killed material (Ward et al. 2004).

Case 5: Cofiring With Agricultural Residues (Chillicothe, Iowa)

In 2000 and 2001, the Chariton Valley Biomass Project completed successful test burns over a 2-month period, 26 days of which some switchgrass was burned (Amos 2002). Cofiring test objectives included (1) evaluating impacts on boiler performance (including slagging, fouling, and/or corrosion), (2) evaluating impacts on flue gas emissions, and (3) evaluating fuel handling and processing systems, including particle size reduction and dust control.

More than 1,269 tons of switchgrass were combusted to achieve a 3 percent heat input for the 725-MW plant. On several single days, more than 100 tons of switchgrass were burned. An advantage of using switchgrass as the cofiring fuel is that relatively low power requirements were needed to reduce particle sizes for use in a PC system (compared to wood cofiring). In the Chillicothe test burns, switchgrass particles were typically less than 1/16 inch in thickness and burned quickly in the PC burner (even though some particles were greater than 1 inch in length) (Amos 2002). A disadvantage of cofiring with switchgrass is the potential for corrosion resulting from chlorine contents higher than that of coal.

Discussion

Efforts in 2010

In the past few years, numerous coal plants have announced plans to cofire with biomass, with several plants making serious moves in this direction (table 4). Several different scales, technology types, and biomass resources are being explored. Many of these efforts are aimed at either cofiring at high levels or repowering an entire coal plant to run on biomass. Several cofiring options are available to coal facilities, including the following:

- Cofire at low biomass rates with little equipment modification
- Cofire at higher biomass rates with equipment upgrades
- Convert/repower individual coal burners to be fired with biomass
- Convert/repower entire coal plants to be fired with biomass
- Cofire with torrefied wood

Repowering and high-rate cofiring—
Current cofiring efforts seem to be focusing more on repowering entire units, or cofiring at high rates. Current efforts include burning more than 300 MW of biomass at one location (Burger Plant, Ohio). The motivation for some of these efforts is the need to upgrade older coal plants to meet air quality regulations, and cofiring with biomass is viewed as one means of achieving this goal, even if a capital investment for retrofitting is needed. Cofiring at high rates could offer opportunities to use large volumes of biomass quickly (e.g., hurricane debris or beetle-killed timber); however, potential problems in fuel supply could arise given that biomass residues often have a limited useful "shelflife."

Key issues for cofiring biomass at high rates and/or repowering could include the following:

- Securing long-term fuel contracts for potentially large amounts of biomass
- Identifying the form of fuel that is best suited to the coal plant
- Acquiring capital needed to modify fuel receiving yard, and fuel handling and injection systems
- Processing fuel efficiently when cofiring at PC facilities
- Influencing coal plant operations (e.g., power requirements for fans, stack emissions)
- Addressing potential lack of local support
- Addressing higher levelized costs of electricity (and potential resistance from ratepayers)

Table 4—Summary of current (2010) activity—coal plant conversions and repowering

Name	Location	Operator	Cofire fuel	Description/status
Mount Poso Cogeneration Plant	Bakersfield, California	Red Hawk Energy	Agricultural and residential waste	Expected conversion date is September 2010
Boardman Plant	Boardman, Oregon	Portland General Electric	Torrefied wood or other biomass	Planning to operate coal plant until 2020, then close
Schiller Station	Portsmouth, New Hampshire	Public Service Co. of NH	Wood	In operation since December 2006; burns approx. 400,000 tons/year in fluidized bed boiler
E.J. Stoneman Powerplant	Cassville, Wisconsin	DTE Energy	Wood	Plan to convert a 50 MW-coal plant entirely to wood
Hu Honua Station	Hawaii	Hu Honua Bioenergy, LLC	Agricultural residues	24-MW facility burning local wood and agricultural wastes
Bay Front Station	Ashland, Wisconsin	Xcel Energy	Wood waste from forest harvesting	After repowering, will burn biomass in all three boilers
Charter St. Heating Plant	Madison, Wisconsin	University of Wisconsin	Various biomass fuels	Refire coal boilers with biomass or natural gas; install a new boiler to burn 100 percent biomass
Mitchell Steam Generating Plant	Albany,	Southern Company	Woody biomass	Plan to convert 163-MW coal plant to biomass
R.E. Burger Plant	Shadyside, Ohio	First Energy Corp. (Ohio Edison)	Variety of biomass fuels	Plan to repower two coal units to biomass (up to 312 MW of total biomass energy)
Lakeview Station	Ontario, Canada	Ontario Power	Wood pellets, agricultural residues	Plan to phase out coal generation in Ontario by 2014
Lambton Station	Ontario, Canada	Ontario Power	Wood pellets, agricultural residues	Plan to phase out coal generation in Ontario by 2014
Nanticoke Station	Ontario, Canada	Ontario Power	Wood pellets, agricultural residues	Plan to phase out coal generation in Ontario by 2014
Atikokan Station	Ontario, Canada	Ontario Power	Wood pellets, agricultural residues	Plan to phase out coal generation in Ontario by 2014

Note: MW = megawatt.
Source: Sourcewatch 2010.

Fluidized bed combustion—

In fluidized bed combustion (FBC) systems, material is burned in a bed of inert material (such as sand), that is "fluidized" by air movement. The FBC systems can be modified as circulating FBCs (CFBC), in which material is recirculated to the combustion chamber for further burning. Fluidized bed systems have generally been limited to sizes of less than 300 MW; however, they are now being designed for larger applications, including a 460-MW CFB in Lagisza, Poland (Jantti et al., n.d.), that could be scaled up to the 600- to 800-MW range at a later date.

The FBC and CFBC systems are becoming important as older coal plants can be repowered, opening the possibility of cofiring with biomass over a wide range of conditions. Important advantages of FBC systems can include (Jantti et al., n.d.):

- Their ability to burn fuels over a wide range of moisture content, particle size, and density, potentially including coal, biomass, tire-derived-fuel, agricultural residues, and urban wood wastes
- More efficient heat transfer during combustion results in lower combustion temperatures, in turn lowering NOx emissions
- Lower costs for SO_2 capture because limestone can be added directly to the fluidizing medium (Laursen and Grace 2002) at relatively low cost compared to installing postcombustion scrubbers

Coal plants that install FBC systems as part of retrofits or new plant construction could "open the door" for future use of biomass (even if no biomass is included initially). The Schiller, New Hampshire, repowering is an example of a dedicated biomass FBC unit. Here, one 50-MW FBC runs entirely on wood while the remaining two units operate on coal only (Peltier 2007). The FBC systems have numerous advantages related to their flexible-fuel capabilities that are likely to remain important in new coal plant projects, new wood energy projects, repowering projects, and combinations of these.

Pulverizing biomass materials—

Proper pulverizing biomass for use in PC systems is an important operational consideration. Test burns have shown that a maximum wood particle size of about ¼ inch is needed before being copulverized with coal (Prinzing and Hunt 1998). In test burns at Shawville Generating Station (Pennsylvania), biofuels were processed in a tub grinder followed by trammel screen to achieve this particle size.

However, cofiring at high rates can pose operational challenges to PC systems. For example, when cofiring sawdust up to 8 percent energy value, grinding coal and wood together had negative effects on coal fineness (Savolainen 2003). Other studies found negative impacts on boiler capacity even when only a 3 percent sawdust blend was included (Prinzing and Hunt 1998). However many of the drawbacks

Further work is needed to assess the pulverizing properties of wide-ranging biomass materials including hazard fuel materials, urban wood wastes, and agricultural residues.

of including biomass could be mitigated by using a separate fuel injection system (versus processing wood and coal together). At least one firm manufactures equipment capable of producing a "microchip" product where 96 percent of material is sized less than 0.25 inch maximum dimension (Enviva 2010). Further work is needed to assess the pulverizing properties of wide-ranging biomass materials (including hazard fuel materials, urban wood wastes, and agricultural residues) as well as optimal cofiring levels, impacts on boiler efficiency, and whether separate injection is needed.

Pulverized coal facilities are common in Maryland, with 13 of the 16 coal facilities in the state being PC facilities (Princeton Energy Resources International 2006). Several key issues associated with cofiring in PC systems have been identified:

- Possible interference with SCR emissions equipment when cofiring biomass
- Little capital investment requirements when cofiring at less than 2 percent of energy value
- Capital investments ranging from $150 to $400 per installed kW of bioenergy are likely when cofiring at greater than 2 percent energy value
- Cofiring with biomass was less financially attractive than burning only coal

Torrefied wood—

In the torrefaction process, wood is heated to 200 to 300 °C, driving off volatile compounds in an oxygen-free environment. The result is a darkened, brittle product that has a higher energy content per unit mass than the original biomass source. Because torrefied wood is brittle, it can be pulverized and burned with coal, rather than needing separate handling, processing, and injection systems. This can result in substantial equipment cost savings when cofiring at higher rates. Numerous agricultural residues, including straws and grasses can be torrefied in addition to woody biomass, improving combustion properties of coal systems (Bridgeman et al. 2008).

Torrefied wood has been successfully cofired with coal at a powerplant in Borselle, The Netherlands. Here torrefied wood was copulverized with coal up to 9 percent of energy value in a PC boiler, resulting in no measurable effects or adverse system operation (Weststeijn 2004). Also in The Netherlands, a plant to produce torrefied wood pellets is under construction, with an initial capacity of 60,000 tons per year (R.I.S.I. 2010), with potential scale-up to 100,000 tons per year (Beckman 2010). Torrified wood may be cofired at higher rates than traditional forms of wood, as it more closely resembles coal in many properties. The torrefaction process typically results in considerably less volume than the original feedstock. Thus, the energy density of torrified wood can be on the order of 30 percent higher (Tennessee Valley Authority 2010) and can be economically trucked greater distances than unprocessed wood. Recently, work has been initiated with wet or hydrothermal torrefaction. Loblolly pine (*Pinus taeda* L.) was treated using hot compressed water at 292 to 500 °F (200 to 260 °C). Generally the wet torrefaction process produces a product with higher energy density than the dry torrefaction process (Wei Yan et al. 2009). HM3 Energy, located in Gresham, Oregon, has tested cocombustion of torrefied wood and coal (using a 50/50 blended feed) for up to 2 hours at the Western Research Institute in Laramie, Wyoming. In the tests, designed to simulate a PC-fired utility boiler, no problems were encountered with fuel feeding or combustion, while providing substantial reductions in sulfur emissions (HM3E 2010).

Summary on the Status of Cofiring Facilities

Biomass is a significant renewable energy option for the United States (de Richter et al. 2009) and cofiring is perhaps the best short-term means of reducing CO_2 emissions from coal-burning facilities. Numerous test burns have been conducted with biomass and coal under a variety of plant operating conditions. Although many of these tests were conducted over 10 years ago, there is now renewed interest in cofiring. Current initiatives are often at larger scales, involving conversion of coal burners or entire plants to biomass fuels. The potential biomass feedstocks are diverse and could include greater use of urban wood wastes or biomass salvaged from insect infestations, fire, and other agents. New technologies are also likely to play a role, especially with aging coal plants that may be replacing burners with biomass fuel. Fluidized bed burners allow for a wide variety of fuel types and could see increased use. Ultimately, financial incentives will guide the future direction of cofiring. This could include cap and trade legislation, greater use of renewable energy certificates, and environmental mandates to replace aging equipment. United States facilities can benefit from experiences and lessons learned from Europe, where considerable volumes of biomass have been cofired over the past decade.

The potential biomass feedstocks are diverse and could include greater use of urban wood wastes or biomass salvaged from insect infestations, fire, and other agents.

Metric Equivalents

When you know:	Multiply by	To get
Inches	2.54	Centimeters
Pounds	453.59	Grams
Tons (U.S. short tons)	0.91	Metric tons or megagrams
British thermal units	1,055.06	Joules
Degrees Fahrenheit (°F)	F-32/1.8	Degrees Celsius (°C)

Glossary

co-fire—The use of a supplemental fuel in a boiler in addition to the primary fuel the boiler was originally designed to use (Fehrs and Donovan 1999).

fluidized bed combustion (FBC)—Combustion units that burn fuel in an air-suspended mass (or bed) of particles. Fluidized bed combustion benefits include fuel flexibility and the ability to combust fuels such as biomass or waste fuels (Babcock and Wilcox 2006).

hardgrove grindability index (HGI)—Empirically measures the relative difficulty of grinding coal to the particle size necessary for relatively complete combustion in a pulverized coal boiler furnace. To determine HGI, a 50-gram sample of coal is ground under a fixed load, after which the proportion that is less than 75 microns is recorded (ACARP 2008).

megawatt (MW)—one million watts.

megawatt-hour (MW-hr)—A unit of energy equal to the work done by one [million] watts acting for 1 hour and equivalent to 3.6 x 109 joule (The Free Dictionary, 2012).

pulverized coal (PC) burner—Pulverized coal (PC) boilers are the most commonly used technology in cofiring operations, and in electricity production in general. PC boilers burn finely ground particles of coal in a suspension boiler within the combustion area (Princeton Energy Resources International, LLC. 2006).

super-critical (SC)—Pressures greater than 3,200 pounds per square inch (22.1 MPa) (Babcock and Wilcox 2012).

selective catalytic reduction (SCR)—A technology for reducing certain nitrogen emissions from coal combustion. The SCR process consists of injecting ammonia (NH3) into boiler flue gas and passing the flue gas through a catalyst bed where the NOx and NH3 react to form nitrogen and water vapor (US DOE 1997).

References

ACARP 2008. Hardgrove grindability index. 16 p. http://www.acarp.com.au/Downloads/ACARPHardgroveGrindabilityIndex.pdf. (20 July 2012).

Aerts, D.; Ragland, K. 1997. Switchgrass production for biomass. Research Brief No. 51. http://www.cias.wisc.edu/crops-and-livestock/switchgrass-production-for-biomass/. (03 May 2012).

Amos, W.A. 2002. Summary of Chariton Valley switchgrass co-fire testing at the Ottumwa generating station in Chillicothe, Iowa. Milestone Completion Report. Golden, CO: National Renewable Energy Laboratory. 33 p.

Anon. 2010. From trees to electricity: Colorado Springs utilities begins using woody biomass to generate power. http://www.marketwire.com/press-release/From-Trees-Electricity-Colorado-Springs-Utilities. (03 May 2012).

Austin, A. 2010. Ontario biomass conversion plans progress. Biomass Magazine. http://www.biomassmagazine.com/article.jsp?article_id=4093. (03 May 2012).

Babcock and Wilcox. 2006. Internal recirculation circulating fluidized-bed boilers—a simplified approach to flexibility and reliability. http://www.babcock.com/. (27 April 2012).

Battista, J.J.; Hughes, E.E.; Tillman, D.A. 2000. Biomass cofiring at Seward Station. Biomass and Bioenergy. 19(6): 419–428.

Baxter, L.; Koppejan, J. 2004. Biomass-coal co-combustion: opportunity for affordable renewable energy. 12 p. IEA 25. Paris, France: International Energy Agency.

Beckman, K. 2010. A breakthrough for second-generation biofuels. European Energy Review. http://www.europeanenergyreview.eu/site/pagina.php?id_mailing=93&toegang=98dce83da57b0395e163467c9dae521b&id=2130. (03 May 2012).

Boylan, D.; Roberts, K.; Zemo, B.; Johnson, T. [N.d.]. Co-milling green wood chips at Alabama Power Company's plant Gadsden Unit 2. 59 p. http://www.cawaco.org/biomass/reportdraftoutlinewoodchips.pdf. (20 July 2012).

Boylan, D.; Bush, V.; Bransby, D.I. 2000. Switchgrass cofiring: pilot scale and field evaluation. Biomass and Bioenergy. 19: 411–417.

Boylan, D.M. 1996. Southern Company tests of wood/coal cofiring in pulverized coal units. Biomass and Bioenergy. 10(2-3): 139–147.

Bridgeman, T.G.; Jones, J.M.; Shield, I.; Williams, P.T. 2008. Torrefaction of reed canary grass, wheat straw and willow to enhance solid fuel qualities and combustion properties. Fuel. 87(6): 605–1006.

Cartledge, J. 2010. FirstEnergy cancels $200m Ohio biomass power project. http://www.brighterenergy.org/19805/news/bioenergy/firstenergy-cancels-200m-ohio-biomass-power-project/. (22 November 2010).

Cobb, J.T., Jr.; Geiger, G.E.; Elder, W.W. III; Barry, W.P.; Wang, J.; Li, H. 2004. Urban wood/coal co-firing in the Bellefield Boilerplant; final report. http://www.osti.gov/bridge/servlets/purl/838442-hMfpdN/native/838442.pdf. (22 July 2012).

De, S.; Assadi, M. 2009. Impact of cofiring biomass with coal in power plants—a techno-economic assessment. Biomass and Bioenergy. 33: 283–293.

Demirbas, A. 2003. Sustainable cofiring of biomass with coal. Energy Conversion and Management. 44(9): 1465–1479.

de Richter, B., Jr.; Jenkins, D.H.; Karakash, J.T.; Knight, J.; McCreery, L.R.; Nemestothy, K.P. 2009. Wood energy in America. Science. 323(13): 1432–1433.

Dubuisson, X.; Sintzoff, I. 1998. Energy and CO_2 balances in different power generation routes using wood fuel from short rotation coppice. Biomass and Bioenergy. 15(4/5): 379–390.

Enviva. 2010. Enviva biomass. http://www.envivabiomass.com/. (03 May 2012).

Faiij, A.; Meuleman, B.; Turkenburg, W.; van Wijk, A.; Bauen, A.; Rosillo-Calle, F.; Hall, D. 1998. Externalities from biomass based electricity production compared with power generation from coal in the Netherlands. Biomass and Bioenergy. 14(2): 125–147.

Fehrs, J.E.; Donovan, C.T. 1999. Co-firing wood in coal-fired industrial stoker boilers: strategies for increasing co-firing in New York and the Northeast. 31 p. http://www.nrbp.org/pdfs/pub18.pdf. (03 May 2012).

Gold, B.A.; Tillman, D.A. 1996. Wood cofiring evaluation at TVA power plants. Biomass and Bioenergy. 10(2/3): 71–78.

Haq, Z. 2002. Biomass for electricity generation. Washington, DC: U.S. Energy Information Administration. 18 p.

Heller, M.C.; Keoleian, G.A.; Mann, M.K.; Volk, T.A. 2004. Life cycle energy and environmental benefits of generating electricity from willow biomass. Renewable Energy. 29(7): 1023–1042.

HM3 Energy, Inc. 2010. Test burns at research facility. http://www.hm3e.com/projects/index.php. (03 May 2012).

Holly, C. 2009. First energy retools coal plant to burn biomass. Coal Power. http://www.coalpowermag.com/plant_design/FirstEnergy-Retools-Coal-Plant-to-Burn-Biomass_204.html. (03 May 2012).

Hughes, E. 2000. Biomass cofiring: economics, policy and opportunities. Biomass and Bioenergy. 19(6): 457–465.

Hunt, E.F.; Prinzing, D.E.; Battista, J.J.; Hughes, E. 1997. The Shawville coal/biomass cofiring test—a coal/power industry cooperative test of direct fossil fuel CO_2 mitigation. Energy Conservation and Management. 38: 551–556.

Hus, P.J.; Tillman, D.A. 2000. Cofiring multiple opportunity fuels with coal at Bailly Generating Station. Biomass and Bioenergy. 19: 385–394.

International Energy Administration Bioenergy Task 32. 2010. International cofiring database. http://www.ieabcc.nl/database/cofiring.php. (20 July 2012).

Jäntti, T.; Eriksson, T.; Hotta, A.; Hyppänen, T.; Nuortimo, K. [N.d.]. Circulating fluidized bed technology—toward zero CO_2 emissions. Finland: Foster Wheeler Energia Oy. 21 p.

Johnson, E. 2009. Goodbye to carbon neutral: getting biomass footprints right. Environmental Impact Assessment Review. 29: 165–168.

Laursen, K.; Grace, J.R. 2002. Some implications of co-combustion of biomass and coal in a fluidized bed boiler. Fuel Processing Technology. 76: 77–89.

Mann, M.K.; Spath, P.L. 2001. A life cycle assessment of biomass cofiring in a coal-fired power plant. Clean Products and Processes. 3: 81–91.

Manomet Center for Conservation Sciences. 2010. Massachusetts biomass sustainability and carbon policy study: report to the Commonwealth of Massachusetts Department of Energy Resources. In: Walker, T.; Cardellichio, P.; Colnes, A.; Gunn, J.; Kittler, B.; Perschel, R.; Recchia, C.; Saah, D.; Walker, T.; contr. Natural Capital Initiative Report NCI-2010-03. Brunswick, M. 182 p.

Marshall, L.; Fralick, C.; Gaudry, D. 2010. OPG charts move from coal to biomass. POWER. http://www.powermag.com/renewables/waste_to_energy/OPG-Charts-Move-from-Coal-to-Biomass_2570.html. (03 May 2012).

Meikle, T. 2010. Personal communication. Plant manager, Drake Power Plant, 700 Conejos St. 1120, Colorado Springs, CO 80903.

Mentz, K.; Pinkerton, J.; Louch, J. 2005. Potential mercury and hydrochloric acid emissions from wood fuels. Forest Products Journal. 55(2): 46–50.

Merriam-Webster. 2012. http://www.merriam-webster.com/dictionary/megawatt. (20 April 2012).

Murray, G. 2010. Phasing out coal. Canadian Biomass. (July/August): 28.

Ney, R.A.; Schnoor, J.L. 2002. Greenhouse gas emission impacts of substituting switchgrass for coal in electric generation: the Chariton Valley Biomass Project. 34 p. http://www.cgrer.uiowa.edu/research/reports/iggap/charrcd.pdf. (03 May 2012).

Peltier, R. 2007. PSNH's Northern wood power project repowers coal-fired plant with new fluidized-bed combustor. POWER. http://www.powermag.com/coal/PSNHs-Northern-Wood-Power-Project-repowers-coal-fired-plant-with-new-fluidized-bed-combustor_211.html. (03 May 2012).

Princeton Energy Resources International, LLC. 2006. The potential for biomass cofiring in Maryland. Maryland Deptartment of Natural Resources. 85 p. http://www.esm.versar.com/PPRP/bibliography/PPES_06_02/PPES_06_02.pdf. (03 May 2012).

Prinzing, D.E.; Hunt, E.F. 1998. Impacts of wood cofiring on coal pulverization at the Shawville Generating Station. Fuel Processing Technology. 54: 143–157.

Renewable Energy World. 2009. Ohio Edison to repower coal plant with biomass. http://www.renewableenergyworld.com/rea/news/article/2009/08/ohio-edison-to-repower-coal-plant-with-biomass. (03 May 2012).

R.I.S.I. 2010. Topell, RWE break ground on torrefied wood pellet mill in the Netherlands. http://woodbiomass.com/woodbiomass/news/North-America/Wood-Energy/Topell-RWE-torrefied-wood-pellet-biomass-Netherlands.html. (03 May 2012).

Robinson, A.L.; Rhodes, J.S.; Keith, D.W. 2003. Assessment of potential carbon dioxide reductions due to biomass–coal cofiring in the United States. Environmental Science and Technology. 37(22): 5081–5089.

Saimbi, S.; Hart, D. 2010. Drax offers model for cofiring biomass. POWER. www.powermag.com/renewables/waste_to_energy/Drax-Offers_Model-for-Cofiring. (03 May 2012).

Sami, M.; Annamalai, K.; Wooldridge, M. 2001. Co-firing of coal and biomass fuel blends. Progress in Energy and Combustion Science. 27: 171–214.

Savolainen, K. 2003. Co-firing of biomass in coal-fired utility boilers. Applied Energy. 74: 369–381.

Smith, J.W. 1998. Supercritical (once through) boiler technology. BR-1658. 9 p. http://www.babcock.com/library/pdf/BR-1658.pdf. (20 July 2012).

Sourcewatch. 2010. Coal plant conversion projects. http://www.sourcewatch.org/index.php?title=Coal_plant_conversion_projects. (03 May 2012).

Spath, P.L.; Mann, M.K.; Kerr, D.R. 1999. Life cycle assessment of coal-fired power production. NREL/TP-570-25119. Golden, CO: U.S. Department of Energy, National Renewable Energy Laboratory. 172 p.

Tennessee Valley Authority. 2010. Technology research area: cofiring torrefied biomass. http://www.tva.gov/environment/technology/torrefied_biomass.htm. (03 May 2012).

Tharakan, P.J.; Volk, T.A.; Lindsey, C.A.; Abrahamson, L.P.; White, E.H. 2005. Evaluating the impact of three incentive programs on the economics of cofiring willow biomass with coal in New York State. Energy Policy. 33: 337–347.

The Free Dictionary. 2012. http://www.thefreedictionary.com/watt-hour. (20 April 2012).

Tillman, D.A. 2001. Final report: EPRI-USDOE Cooperative Agreement: cofiring biomass with coal. Contract No. DE-FC22-96PC96252. Palo Alto, CA: Electric Power Research Institute. 194 p.

Tillman, D.A. 2000. Biomass cofiring: the technology, the experience, the combustion consequences. Biomass and Bioenergy 19: 365–384.

U.S. Department of Energy, **Energy Information Administration. 2009.**

U.S. Department of Energy. 2004. FEMP guide—biomass cofiring in coal-fired boilers. Washington, DC. 40 p. www.eere.energy.gov/femp. (03 May 2012).

U.S. Department of Energy. 1997. Control of nitrogen oxide emissions: selective catalytic reduction (SCR). 28 p. http://www.netl.doe.gov/technologies/coalpower/cctc/topicalreports/pdfs/topical9.pdf.

U.S. Department of Energy, National Renewable Energy Laboratory. [U.S. DOE NREL]. 1999. Biomass cofiring: a renewable alternative for utilities and their customers. DOE/GO-10099-758. 4 p.

U.S. Department of Energy, National Renewable Energy Laboratory [U.S. DOE NREL]. 2000. Biomass cofiring: a renewable alternative for utilities. 2 p. http://www.nrel.gov/docs/fy00osti/28009.pdf. (03 May 2012).

vanRee, R.; Korbee, R.; de Lange, T. 2000. Biomass cofiring potential and experiences in The Netherlands. ECN-RX--00-035. The Netherlands: Netherlands Energy Research Foundation. 18 p.

Ward, J.E.; Mackes, K.H.; Lynch, D.L. 2004. Wood wastes and residues generated along the Colorado Front Range as a potential fuel source. Res. Pap. RMRS-RP-50. Fort Collins, CO: U.S. Department of Agriculture, Forest Service, Rocky Mountain Research Station. 9 p.

Weststeijn, A. 2004. First torrefied wood successfully cofired with coal. Essent Energie BV. http://www.techtp.com/recentpapers/TW%20cofired.htm. (03 May 2012).

Wei, Y.; Acherjee, T.C.; Coronella, C.K.; Vasquez, V.R. 2009. Thermal pretreatment of lignocellulosic biomass. Environmental Progress and Sustainable Energy. 28(3): 435–440.

Zabetta, E.C.; Hotta, A.; Moulton, B.; Hiltunen, M. 2009. Biomass and waste co-combustion—European experience. Electric Power 2009. 15 p. http://www.fwc.com/publications/tech_papers/files/TP_FIRSYS_09_01.pdf. (20 July 2012).

Zerbe, J.I. 2010. Review of cellulosic ethanol production facilities. Unpublished database. On file with: J. Zerbe.

Zhang, Y.; McKechnie J.; Cormier, D.; Lyng, R.; Mabee, W.; Ogino, A.; MacLean, H.L. 2010. Life cycle emissions and cost of producing electricity from coal, natural gas, and wood pellets in Ontario, Canada. Environmental Science and Technology. 44(1): 538–544.

Pacific Northwest Research Station

Web site	http://www.fs.fed.us/pnw/
Telephone	(503) 808–2592
Publication requests	(503) 808–2138
FAX	(503) 808–2130
E-mail	pnw_pnwpubs@fs.fed.us
Mailing address	Publications Distribution Pacific Northwest Research Station P.O. Box 3890 Portland, OR 97208–3890

U.S. Department of Agriculture
Pacific Northwest Research Station
333 SW First Avenue
P.O. Box 3890
Portland, OR 97208–3890

Official Business
Penalty for Private Use, $300