F I N A L R E P O R T

of the

Governor's Task Force on Co-Firing

The State of West Virginia
Governor Cecil H. Underwood

February 2000

Preface and Acknowledgements

The Governor's Taskforce on Co-firing was initiated in October 1998 through the vision and efforts of Corky DeMarco, Director of the Governor's Office of Operations. The charge to the Taskforce was to assess the potential of co-firing strategies for enhancing the continued use of coal in West Virginia power generation plants.

The taskforce believes that, in many ways, co-firing is a win-win strategy. Co-firing with biomass, natural gas, tire derived fuel or other materials can improve emissions from existing coal burning power plants; it is a low-cost approach to use of renewable fuels; and, it can solve industrial waste disposal problems while recovering energy from materials that could otherwise end up in landfills.

The work of the taskforce is very timely due to the emergence of critical issues affecting coal-based power generation: increasingly stringent emissions limits on nitrogen oxides, sulfur dioxide, particulates and greenhouse gases; deregulation and restructuring of the power generation industry; and renewable energy portfolio standards being proposed in federal and state restructuring legislation.

Through this taskforce, the coal industry, the oil and natural gas industry, the power generation industry, and the forestry industry have come together to seek synergistic, workable strategies for co-firing that are right for West Virginia's energy future. This report, which has been coordinated through the West Virginia University National Research Center for Coal and Energy, is a synthesis of the ideas, information, and recommendations the taskforce has gathered over the past year.

The time, ideas and written contributions of the taskforce members are sincerely appreciated, as is the expert information provided by the taskforce resource people. Ms. Laura Del Col of the NRCCE has provided very competent assistance with editing and producing this report.

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Final Report of the Task Force

1.0 Report Summary

1.1 Background

West Virginia is blessed with some of the nation's most abundant energy resources. A combination of nonrenewable and renewable energy resources such as coal, natural gas, biomass, wind and water can enable West Virginia to have an enviable competitive energy future. Of these resources, low cost coal is the most abundant, but its use is threatened by environmental and regulatory constraints.

Many energy strategists believe that coal can be used for power generation for decades to come. At some point in the future, advanced generation technologies such as gasification combined cycle and fuel cells will use coal with greater efficiency and less environmental impacts than today's technologies. During the transition to such advanced technologies, a variety of strategies for using coal for power generation will be pursued. One relatively inexpensive strategy is co-firing of coal with biomass, natural gas, tire-derived fuel, farm animal wastes, or combustible byproducts from other industries.

In order for co-firing to be accepted by the power generation industry in West Virginia, it must produce electricity at a lower production cost than using coal alone. Environmental and regulatory advantages must offset the cost of installing and operating the co-firing facility. Otherwise the cost of co-firing installations could be stranded in a competitive market.

Because it offers a relatively inexpensive way to improve emissions and use renewable fuels, co-firing can enhance the potential for increased power generation in West Virginia in a competitive environment. In fact, competition in the generation of electricity as a result of deregulation across the nation will mandate that such generation be accomplished in the most cost effective and environmentally acceptable manner.

1.2 Recommendations

Commercial implementation of proven co-firing technologies will require a concerted cooperative effort by industry, government and research organizations. The state should seriously consider giving tax or emissions credits and other economic incentives to jump-start this new dimension of West Virginia's energy industry. Credits could be given for use of co-firing fuels that promote environmental sustainability -- for example, biomass grown on reclaimed mine lands, coalbed methane, landfill gas and tire derived fuels.

The State of West Virginia can play an important role in facilitating co-firing as part of a comprehensive energy strategy. It can be the first state in the nation to face the fuel source problem directly and in a balanced manner. Initial recommendations for state actions relative to co-firing include the following:

- Assuring that co-firing additions that increase a plant's output or improve its compliance do not undergo excessive new-source permitting.

- Reviewing all DEP regulations that apply to the use of co-firing fuels and simplifying the process so that companies feel sure their investments will not be stranded by regulations.

- Certifying that green power is part of the energy strategy of West Virginia and that it is in the best interest of the state to encourage co-firing, carbon sequestration, and use of renewable fuels.

- Creating an efficient, user-friendly, one-stop permitting/certification process for co-firing whereby companies can make investment decisions based on economics, environmental issues, and resource development information.

1.3 Biomass

Co-firing with biomass can substantially reduce SO_2 and NOx emissions. Biomass also has the advantage of being a renewable resource. The feasibility of co-firing wood wastes with coal at levels of up to 10 percent has been established during several demonstrations. Although site-specific assessments are always required, boiler performance is generally not affected at these levels. The Pittsburgh Coal Conference proceedings of October 1999 are a good source of information on these tests.

However, the value of biomass to a utility is much less than that of coal. Its moisture content and handling characteristics are very different from coal's, and it requires special equipment for size reduction. Long-term contracts are generally not available, and West Virginia's sparse infrastructure makes transporting biomass expensive. In order to be economically viable, biomass must cost less than half as much as coal.

Using pelletized coal/biomass composite fuels can eliminate some of the problems with handling characteristics. Westvaco has had great success with a composite fuel called E-Fuel.

1.4 Natural gas

A number of electric utilities have begun co-firing with natural gas as a cost-effective way to reduce acid rain precursors, especially during the summer. Natural gas co-firing also reduces sulfur dioxide, fine particulates, and carbon dioxide emissions in coal-fired power plants.

Natural gas can be used in at least three ways as a co-firing fuel with coal: gas fired burners can be used to preheat coal prior to combustion, thus releasing fuel nitrogen and other volatiles; natural gas can be combusted concurrently with coal, or it can be used in a reburn mode, which generally provides larger NOx reductions. Gas reburn technologies have been shown to reduce NOx emissions by an average of 40 to 60 percent.

1.5 Other Co-Firing Fuels

Utilities across the country have found co-firing with waste tires to be not only a good way to reduce pollutants, but also a way to solve a major disposal problem. There are no utilities currently using tire-derived fuel in West Virginia, but Allegheny Power and Capital Cement are preparing to do so.

Landfill gas, coal bed methane, petroleum coke and municipal/industrial wastes are other possible co-firing fuels. Furthermore, gasification or liquefaction of mixtures of “opportunity fuels” such as biomass, animal wastes and coal fines may provide additional sources of co-firing fuels.

1.6 Reasons for Co-Firing

Some of the environmental, economic and customer service reasons for co-firing are listed below:

Environmental compliance strategies for coal-burning power plants:

- Mitigate fossil CO_2 emissions from coal-fired boilers
- Reduce NOx and SO_2 emissions from cyclone and PC boilers
- Provide a mechanism for generation and sale of cost-effective, dispatchable green or renewable power

Economic benefits:

- Co-firing in existing boilers is potentially a least-cost way for coal-burning utilities to use renewable fuels
- Co-firing opens a market for biomass and other co-firing fuels that have a "green" or renewable/sustainable energy potential
- Co-firing could save money in competitive markets through fuel diversity
- Co-firing could help companies get credits for early voluntary greenhouse gas abatement measures

Special services to utility clients (customer retention):

- Co-firing uses fuels such as wood wastes or used tires that may present disposal problems for customers
- Co-firing is a proactive approach to meeting Renewable Energy Portfolio Standards
- Attention to the problem may encourage legislation favorable to the use of refuse-derived fuels

1.7 Carbon-Neutral Strategies

The sequestration of carbon in forests, oceans, croplands and soils is a powerful natural control for limiting the amount of carbon dioxide that is dispersed into the atmosphere. Studies indicate that forests in the eastern U.S. can absorb over 10% of the carbon emissions from fossil fuel combustion and cement production. The sequestering ability of West Virginia forests suggests that a carbon-neutral policy by the state may have merit.

Under this strategy, the state would manage forests for sequestration. These lands would have additional value, since they provide selected harvest, recreation, biodiversity and other environmental benefits. Managing the land will require cooperation between private and public interests. Monitoring and verification is also needed. The latest in Geographical Information Systems and other tools make such metrics possible.

A power plant developer could take advantage of the sequestration potential of these lands by burning fossil fuels in proportion to the amount of available carbon control. Harvested biomass could be used for co-firing with fossil fuels. The harvested biomass and the carbon sequestered should qualify as a total renewable energy system.

Much must be done to help assure such a scenario, but the task force believes the process should start in West Virginia. The use of forests as a source of biomass co-firing fuel and as a carbon sink is a strategy for sustainability that would allow the state to continue reaping the economic benefits of its fossil energy resources while complying with potential limits on carbon dioxide emissions.

2.0 Factors Driving Co-Firing

2.1 Environmental Issues

Over half the electric power generated in the United States is produced from coal combustion. Large coal-fired boilers emit significant amounts of sulfur dioxide (SO_2), nitrogen oxides (NOx), particulate matter (PM), hazardous air pollutants (HAPs) and greenhouse gases. These emissions are associated with a number of environmental problems, including acid rain, fine particulates, ground-level ozone, regional haze (visibility) and global warming.

Several federal regulations affect large coal-fired boilers. Title IV (Phase II) of the Clean Air Act will reduce allowable emissions of sulfur dioxide in the year 2000. The U.S. EPA established new air quality standards for ground-level ozone and fine particulate matter ($PM_{2.5}$) in July 1997. Then in October 1998, the EPA published a final rule that requires 22 states, including West Virginia, to significantly reduce NOx emissions to help control ground-level ozone (smog). Both the revised standards and the final NOx reduction rule are in litigation. Regardless of the outcome, it seems likely that NOx and particulate emissions will have to be reduced. NOx, SO_2 and PM all contribute to regional haze. A recent EPA rule (July 1999) requires states to assess national parks and wilderness areas and develop plans to improve visibility to "background" levels.

NOx and SO_2 also contribute to acid deposition, including acid rain, which contributes to lake and stream degradation. Initiatives such as the Chesapeake Bay Program are studying atmospheric deposition in the eastern U.S. and may recommend further SO_2 and NOx emission reductions. Additionally, there is increasing interest in reducing electric utility HAP emissions, including mercury, dioxin and other high profile toxins. Finally, because of concern over greenhouse gases and global warming, there is the longer-term prospect of regulation of carbon dioxide.

Despite the host of environmental issues associated with coal, the U.S. will almost certainly continue to rely heavily on it for electricity generation in coming decades. Therefore, utilities and policymakers must find cost-effective modifications that will make existing coal-fired plants more environmentally acceptable.

For these reasons, there is growing interest in co-firing of coal with more environmentally acceptable fuels, such as biomass or natural gas. In addition to reducing CO_2, co-firing tends to reduce emissions associated with acid rain because the co-firing fuels contain less sulfur than most coal does.

2.2 Electric Industry Restructuring

For much of the 20th century, the federal and state governments have regulated production and sale of electricity for both resale and end use. Utilities had to seek approval of the appropriate agency to build generating facilities if costs were to be passed on to ratepayers. They also had to have rates approved. Regulatory commissions scrutinized the utilities' fuel purchases to see how much of the cost was prudent and recoverable from customers. In exchange for such government oversight, electric utilities were allowed to exist as vertical monopolies within their assigned franchise territories.

In West Virginia, abundant supplies of high-quality coal and access to large water sources have made the state the largest net exporter of electricity in the nation.

The current system of integrated utilities with definitive service territories has resulted in substantial rate disparities across the nation, even among neighboring utilities. The rate differences have been caused principally by the cost of generation. These disparities, coupled with competitive market trends in other utility industries, have brought about a call for deregulating electric generation and allowing an open and free market to determine the ultimate source, location and price of electricity. The federal government has already opened up the wholesale electric market and has ordered open access to all electric transmission systems for wholesale sales. Virtually every state -- including West Virginia -- has begun and/or completed deregulation of generation. Nearly half the states, including our neighboring states of Pennsylvania, Virginia, Ohio and Maryland, have adopted a deregulation plan.

The Public Service Commission of West Virginia (WVPSC) began a review of the deregulation issue two years ago, involving a host of electric industry, consumer and government stakeholders. In 1998, the Legislature called for continued review of the many complex issues involved and authorized the WVPSC to work with stakeholders to develop a plan for deregulating generation in the state. After months of study and review (in which no consensus was reached on the major issues), the WVPSC issued an order later in 1998 calling for public hearings and submission of formal testimony on the major issues. This process is taking place throughout 1999 and may lead to development of a deregulation plan that will be presented to the Legislature for approval.

West Virginia can only benefit from deregulation and competition in the generation of electricity and should move forward in implementing a deregulation plan. As the largest exporter of electricity in the nation, the state is already primed to enter new and expanded markets for this commodity. However, competition will mandate that generation be accomplished in the most cost effective and environmentally compliant manner. Co-firing offers tremendous possibilities for achieving this while still emphasizing the burning of West Virginia coal as the major generation fuel source.

2.3 Renewable Energy Portfolios

For some time now, there has been growing interest in expanded use of renewable energy sources in the generation of electric power. Restructuring of the electric utility industry is providing new opportunities for use of renewables as part of the power generation mix in the United States.

Recent support for renewables has come in the form of proposed Renewable Energy Portfolio Standards (REPS) – suggested percentages of generation, from four to 20 percent, which must fall in the renewable category. What that category consists of has not been clearly established. All parties seem to agree that solar, wind and biomass are renewable energy sources, but there is disagreement as to whether hydro energy is renewable. Some claim that hydro installations, particularly large ones, damage the environment. Hydro is also judged to be a developed resource because of the substantial amount of hydro generation throughout the nation – nearly 10 percent of the total generating capacity. By contrast, solar, wind and biomass combined account for less than four percent of U.S. generation capacity.

The REPS proposals include credit trading, which would allow generators or retail suppliers to meet the standard by buying credits from certified renewable generators rather than generating the power themselves.

Proposals to support renewables have been included in neighboring states' electricity restructuring legislation. Pennsylvania legislators established a sustainable energy fund, which comes from a charge on transmission and distribution services on wires business. The charge is currently $.0001 per kWh. New Jersey has a 2% REPS, including hydro, in its restructuring bill. In Ohio, Maryland and other states, net metering and standards for distributed generation and interconnections are being developed.

At the federal level, a REPS has been included in a number of proposed restructuring bills. The Clinton administration's restructuring legislation proposes that by the year 2010, electric power generators should use renewables for 7.5 percent of their total generation mix.

3.0 General Status of Co-Firing Technologies

3.1 Biomass

The word "biomass" typically refers to agricultural and forest products or residues derived from living plants, but the term has also been used for landfill gas and other organic wastes.

Living plants absorb carbon dioxide. Then when biomass is burned, CO_2 containing carbon is recirculated to the atmosphere. Thus, the entire process of growing, burning, and regrowing (replanting) biomass is nearly CO_2-neutral. In some cases, the bio-cycle can sequester additional CO_2 by fixing carbon in the soil.

Another way biomass co-firing cuts down on greenhouse gases is by keeping plant material out of landfills, where methane – a more effective greenhouse gas than CO_2 -- is generated through decomposition. Co-firing with biomass could be seen as a form of waste disposal, which could save a utility money or let it provide a special service for a customer.

Residues and waste products from lumber processing and wood manufacturing yield biomass fuels such as wood chips, cordwood, sawdust, bark, wood shavings or ground-up wood, and various other forms of chipped sawmill wastes. Other forms of burnable biomass include straw, corncobs, nutshells, seed hulls, pinecones, and certain food processing and agricultural wastes.

Wood is an underused source of energy despite having a number of advantages over fossil fuels. Woody biomass is a renewable natural resource. Its renewability can be as short as 3-5 years in the case of willow trees cultivated in energy plantations. Wood is also a cleaner-burning fuel than coal, although it is not as clean as natural gas. Both SO_X and NOx emissions are greatly reduced with wood as opposed to coal.

A disadvantage of woody biomass for energy use is that because of its moisture content, its Btu value is lower than that of coal or natural gas. A second potential disadvantage is that enough woody biomass may not be available to support the co-firing requirements of West Virginia's coal-burning power plants. Materials handling aspects have also been a minor problem for some users of woody biomass.

Options for co-firing biomass include mass-burning the biomass by simply mixing it with coal on the storage pile; using a separate fuel-receiving, storage, and boiler feed system; and producing composite fuels. Gasification of biomass – i.e., converting solid biomass to a gaseous co-firing fuel – is another potentially efficient option.

Mass-burning a simple mixture of biomass and coal can work if the components are properly mixed and don't segregate during handling, and if the unit is not feeder- or pulverizer-limited. The handling characteristics (bulk density, moisture content, particle size/shape/compressibility, etc.) of biomass are different from those of coal, and the combustion characteristics are very different. If a mixture of biomass and coal segregates, clumps of biomass will enter the boiler, resulting in high fuel variability and reduced boiler efficiency. Use of a separate system to feed biomass to the boiler avoids these problems.

The cost of biomass depends on how close a utility is to a source of the fuel. A second factor is the amount of processing needed to prepare the biomass for introduction into the boiler. For cyclone boilers a fuel specification of 3/4" x 0" may suffice. If NOx reduction is a consideration, 1/4" x 0" will be beneficial. For pulverized coal boilers, a 1/4" x 0" fuel will be required.

3.1.1 DOE/EPRI Biomass Co-Firing Program

In 1992, the Electric Power Research Institute (EPRI) began a program with the Tennessee Valley Authority (TVA) to commercialize the co-firing of biofuels with coal in large-scale electric utility boilers. The program involved engineering evaluations of TVA generating stations and conceptual designs and costs for ten of TVA's coal-fired power plants. Both low-level (1 to 5% of the heat coming from the wood fraction) and mid-level co-firing rates (10 to 15% of the heat coming from the wood fraction) were evaluated.

In 1996, the DOE's Federal Energy Technology Center (FETC) became a co-funder of the biomass co-firing research program, and in 1998, the DOE's Office of Energy Efficiency and Renewable Energy, Biomass Power Program joined in. The program is meant to see how well co-firing biomass in utility boilers reduces carbon emissions.

To date, six different electric utility sites under the current DOE/EPRI cooperative agreement have completed co-firing tests. These tests were done at the GPU/Penelec Seward Station, New York State Electric and Gas Greenidge Station, Tennessee Valley Authority's Allen and Colbert Plants, Madison Gas & Electric, and Northern Indiana Public Service Company Michigan City Plant. A summary of the test sites that have completed the parametric co-firing tests is in Table 1.

Table 1. Co-firing tests sponsored by the DOE/EPRI Cooperative Agreement

Utility and Plant	Boiler Capacity and Type	Biomass Heat Input (max)	Biomass Type	Average Moisture	Coal Type	Biofuel Feeding
TVA Allen	272 MW Cyclone	10%	Sawdust	44%	Illinois basin, Utah bituminous	Blending biomass & coal
TVA Colbert	190 MW wall-fired	1.5%	Sawdust	44%	Eastern bituminous	Blending biomass & coal
NYSEG Greenidge	108 MW tangential	10%	Wood waste	30%	Eastern bituminous	Separate injection
GPU Seward	32 MW wall-fired	10%	Sawdust	44%	Eastern bituminous	Separate injection
MG&E Blount St.	50 MW wall-fired	10%	Switchgrass	10%	Midwest bituminous	Separate injection
NIPSCO Mich. City	469 MW cyclone	6.5%	Urban wood waste	30%	PRB, Shoshone	Blending biomass & coal

Construction is in progress at two sites for long-term continuous co-firing demonstrations, which will make it possible for interested companies to visit sites of ongoing operations and for operating staff to improve the technology through hands-on, day-to-day experience.

<u>Efficiency implications of co-firing</u>

Since biomass has a higher volatility than coal, biomass co-firing has some potential to increase overall boiler combustion efficiency by reducing unburned carbon in the ash as well as the amount of excess air required. However, the higher moisture in the biomass usually offsets these benefits. The net result is a slightly lower boiler efficiency than that of 100% coal combustion.

<u>Impact of co-firing on airborne emissions</u>

Most biofuels are very low in nitrogen (e.g., less than 0.2 percent N in the ultimate analysis). The DOE/EPRI program has shown NOx reductions on the order of 7% to 10% with 10% biofuel co-firing, and reductions of 12% to 14% with 15% co-firing.

The extent to which substituting biomass for coal effects SO_2 emissions depends on the sulfur content of the coal being burned and on the percentage co-firing on a Btu basis. Sulfur emissions will go down to the extent that Btu’s from wood or other biomass displace the Btu's from coal. The economic value of this substitution also depends on the sulfur content of the coal and on whether the unit has a scrubber.

Biomass affects fossil CO_2 emissions in the same way it affects SO_2 emissions. The carbon dioxide generated from burning biomass is considered as recycled carbon within the biosphere rather than as carbon added to the biosphere. Consequently there is a direct replacement approach, with an adjustment for any efficiency differences. This approach to fossil CO_2 emissions reduction has been shown to be the least-cost option directly associated with energy generation.

Most biofuels are lower in ash than most coals. During several tests, opacity decreased as the percentage of biomass increased. In other tests, opacity climbed when the biomass portion of the fuel feed was increased to between 15 and 20 percent. Typically, premium biomass materials such as wood waste do not contribute to opacity because they are inherently low in ash.

Long-term demonstration tests

If utilities are to accept biomass co-firing, there must be longer demonstrations. Two demonstrations are under way, with each site addressing specific aspects of co-firing. The sites are the GPU Genco Seward Station and the Northern Indiana Public Service Co. (NIPSCO) Bailly Station.

Seward co-firing demonstration

The Seward Generating Station of GPU Genco (recently sold to Sithe) will demonstrate moderate percentage co-firing in a wall-fired PC, injecting the biomass separately into the boiler without introducing it through the pulverizers. At the same time, the biomass will be injected down the center-pipe of the existing coal burner and diffused into the center of the coal flame. Co-firing levels as high as 10 percent (heat input basis) will be used. The tests will consider short and long-term impacts on boiler capacity, efficiency, stability, emissions, slagging and fouling, and related operations concerns. A tangentially fired 147 MWe unit at the Seward Station will also be co-firing at five percent.

The Seward tests will address the use of utility-generated wood wastes such as poles, reels and pallets. The facility is almost complete, and testing should begin in the fall of 1999.

Bailly tri-firing demonstration

The Bailly Generating Station of Northern Indiana Public Service Co. will be used to demonstrate co-firing and tri-firing wood wastes and petroleum coke with coal. The two fuels complement each other with respect to BTU content, volatility, sulfur content, and cost. Blending such dissimilar opportunity fuels may provide a key to successful use of co-firing.

The project will involve three months of construction and nine months of testing. The tests, along with modeling support, will help determine an optimum blend. That blend will then be burned for six months.

3.1.2 Composite Fuels

Coal/biomass composite fuels eliminate some of the problems with biomass co-firing. Fuel variability, handling, and feeding are controlled by blending the biomass with coal in the proper proportions to control fuel composition, and therefore combustion characteristics, and by pelletizing the mixture to increase energy density, improve handling characteristics, and prevent segregation of the components. As long as such a fuel can be handled, fed, and burned conventionally, the power station does not need a new boiler or handling system, and its operations are not affected. However, pelletization is expensive.

CQ Inc. has developed an economical method of producing fuel from a paper-making waste sludge composed of wood fibers too short for use in paper manufacture, a waste plastic used to line food container cartons, and fine-sized coal. The coal, biomass, and waste are blended in the proportions of approximately 75/20/5 and pelletized to produce a product called E-Fuel®.

The first E-Fuel production plant was built in Tyrone, Pa., to serve a stoker boiler supplying steam to a paper mill operated by Westvaco. Based on 1997 data (Akers, et. al, 1997), Westvaco saved over $300,000 per year in fuel purchase and waste disposal costs (see Appendix 1, Table 1). CQ Inc. is obtaining a coproduct determination from the state of Pennsylvania. This determination will allow sale of E-Fuel on the open market without any other approvals or permits.

Westvaco performed combustion tests that showed reductions of 40 percent in SO_2, 19 percent in NOx and 52 percent in particulate emissions with E-Fuel (Appendix 1, Table 2). Also, the use of a biomass component reduces CO_2 emissions. The Pennsylvania Department of Environmental Protection accepted Westvaco's use of E-Fuel as a reasonable achievable control technology (RACT) to reduce NOx emissions. Both Westvaco and the DEP have won environmental awards by using E-Fuel.

<u>Opportunities for coal suppliers and users</u>

Pelletizing coal typically costs between $5 and $10 per ton of pellets produced. If a commercial binder or thermal drying is required, costs can exceed $10/ton. Production of composite fuels is unlikely to be economical unless producers can avoid waste disposal costs or obtain a premium price, or the government provides a financial incentive such as tax credits.

The first E-Fuel plant avoided waste disposal costs of almost $1 million per year. If cost savings of this magnitude can be applied against the high cost of pelletizing, the economics of pelletizing improve markedly. The economics of pelletizing can also be improved if a coal producer can take difficult-to-market fines and convert them to a premium stoker fuel. In the case of Westvaco, the difference between steam and stoker prices was $8/ton, enough to offset at least part of the cost of pelletizing.

3.1.3 Biomass Residues from Logging and Wood Processing

The most prevalent forms of woody biomass that are readily available in West Virginia are harvesting/logging residues and wood manufacturing residues, which include sawdust, chips, bark, slabs/edgings/end trim, and shavings. It is important to note that chips, bark, and shavings have a variety of markets and are generally less available as biomass fuel than sawdust.

<u>Logging residues</u>

Byproducts of logging include unwanted logs, limb wood, and tops. A study of logging residues completed in 1995 by researchers at West Virginia University collected information on logging residue pieces that were at least four inches in diameter and at least four feet in length.

The data were collected in each of the West Virginia Division of Forestry (WVDOF) districts (see Figure 1). Table 2 shows the average volume (ft^3 per acre) and average weight (tons per acre) by WVDOF district and the statewide totals.

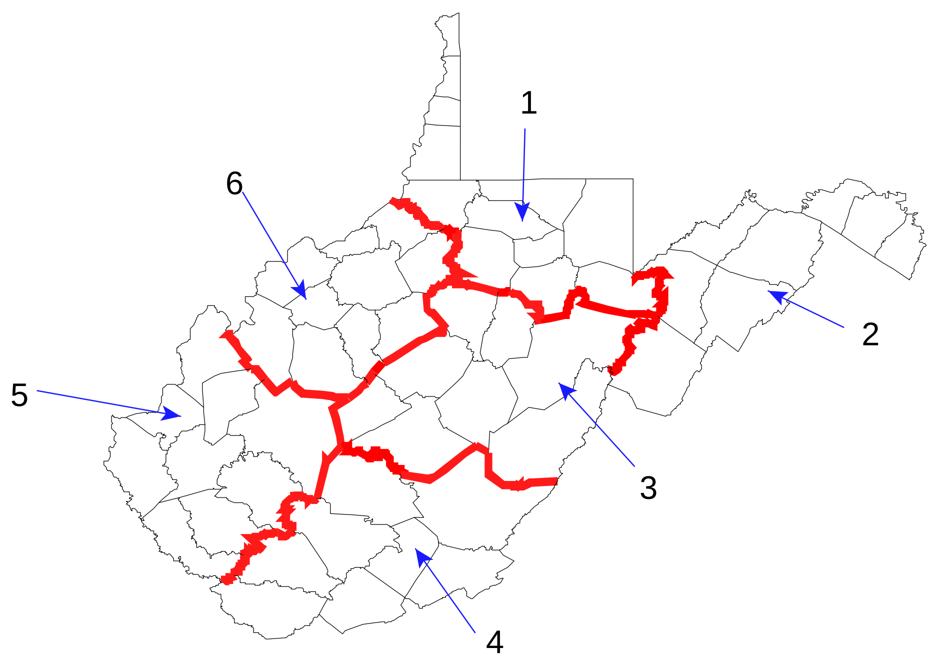

Figure 1. West Virginia Division of Forestry Districts

Table 2. Mean volume per acre (ft^3/acre) and Mean weight per acre (tons/acre) of Logging Residues in West Virginia Division of Forestry Districts, 1995.

District	Volume (ft^3/acre)	Weight (tons/acre)
1	395.2	6.5
2	211.3	3.7
3	549.0	9.0
4	928.7	15.0
5	337.8	6.2
6	591.3	10.4
Statewide	504.4	8.4

Based on WVDOF estimates, the acreage harvested annually in West Virginia is approximately 200,000 acres. With an average of 8.4 tons per acre being left after harvest, annual availability of logging residues is approximately 1.68 million tons.

Mill Residues

The Appalachian Hardwood Center at West Virginia University conducts an annual survey of wood products firms in West Virginia to ascertain the availability of sawdust, bark, chips, shavings, and slabs/edgings/end trim. The 1998 survey (see Appendix 2) was answered by 113 of the 376 residue producers in the state. Although this represents less than a third of the potential available residue, it does show that every week utilities should have access to at least 28,597 tons. This includes 9,103 tons of sawdust, 7,842 tons of bark, 10,763 tons of chips, 15 tons of shavings, and 871 tons of slabs, edgings and end trim.

While these figures indicate physical availability, economic availability will depend upon the type of residue, the demand, and particularly on the distances the residue must be transported. One can expect delivered prices to be greatest for chips and least for sawdust. Chip prices can be expected to cost up to the mid-$20 per ton range. Green sawdust prices can be expected to range up to $15 in price per ton.

An example

Suppose a utility company uses about 17 million tons of coal annually, with an average Btu content of 12,000 Btu's per pound. Assuming that a REPS of 7.5 percent is met with biomass, the utility would have to replace 1.275 million tons of coal with a biomass fuel.

Assuming moisture content of 40 percent, the Btu value per pound of wood residue is about 5,000. Thus, each pound of coal will require 2.4 pounds of wood in order to provide equivalent Btu's. Replacing the 1.275 million tons of coal with wood will require 3.06 million tons of biomass annually.

Logging residues would, at current harvest levels, yield 1.68 million tons. The total wood residue available annually, based on the AHC study, is 1.49 million tons. Combining the two totals would yield 3.17 million tons annually, approximately the amount needed.

While the physical availability of biomass roughly meets the requirements under the assumed scenario, the economic availability presents a much more difficult issue. Costs of delivered residues, stability and consistency of supply, additional processing (for logging residues, chipped and otherwise, and other solid wood residues), maintaining acceptable quality, and overall coordination are issues that need to be addressed.

3.1.4 Technical Issues

A basic consideration is the level of co-firing that can be supported without harming unit performance. Pulverized coal boilers generally can fire up to five- percent biomass on a mass basis when the fuel is blended directly with the coal feed. For levels above five percent, up to 20 percent biomass may be accommodated when the biomass is fed separately into the boiler. For cyclone boilers, 15-20 percent biomass co-firing on a mass basis is typical. Fluidized bed boilers should be able to accommodate higher levels of co-firing. In most instances, the capacity levels are determined by the feeder or pulverizer capacity and by the ability to find enough biomass at reasonable prices for co-firing at higher percentages.

Operating the boiler with greater than 5 % biomass co-firing results in an efficiency penalty which must be considered in the analysis of the individual project. The combustion characteristics of a mixture of ingredients are not always the average of the mix. Coal and biomass can interact in unexpected ways in a boiler.

Certain classes of biomass contain high levels of certain alkali materials that can lead to slagging and fouling in utility boilers and heat exchangers if not carefully controlled. These relatively high levels are not typically found in hardwood residues, however. Furthermore, dilution with coal (at the 95% level) minimizes problems with ash.

Biomass fuel may exacerbate fine-particle emissions in some coal-fired power plants. Any concerns of this nature should be investigated in advance through pilot or laboratory testing.

Commingled biomass/coal ash cannot be used as an admixture to concrete because of ASTM regulations. Consequently, utilities currently selling ash for this use would pay a major economic penalty. However, efforts are under way to have the restriction changed.

3.1.5 Cost

Since delivered biomass is likely to cost more than coal, site-specific economic analysis is necessary to determine the viability of any co-firing project. A good example is the cost of SO_2 allowances that are generated by low or no SO_2 content in biomass fuels. The benefits of NOx reductions may be quantified in terms of avoided costs of modifying burners.

Use of a biomass waste that has a high tipping fee can help make the economics of co-firing attractive; however, tipping fees may decrease in a competitive market.

3.2 Natural Gas/Coal Mine Methane

A number of electric utilities have begun co-firing with natural gas as a cost-effective way to reduce acid rain precursors, especially during the summer. Natural-gas "reburn" schemes have been shown to reduce nitrogen oxide emissions in particular. Natural gas also reduces sulfur dioxide, fine particulates, and carbon dioxide in coal-fired power plants. For this reason, almost all new electric power plants are either natural-gas-fueled combustion turbines or combined cycle units designed to provide intermediate or peaking electrical supply.

3.2.1 Existing Boiler Designs

Natural gas can be used to improve environmental compliance at existing coal-fired power plants, particularly in the area of NOx reduction. During the last 10-15 years, at least 4,000 MW of generation have tested gas co-firing in documented tests. This testing has covered a range of pulverized coal fired boiler designs and also a wide range of boiler sizes. Following are descriptions of five technologies using natural gas co-firing to control NOx.

<u>Conventional gas reburning</u>

The reburn process is an in-furnace NOx emission control technology that diverts some of the fuel and combustion air flows from the main burners and injects them downstream of the main flame or fireball. In general, the reburn process is a three-staged combustion process with staging for both fuel and air, which provides three consecutive combustion zones. The diverted or reburn fuel can be the same as the main fuel, or different. The most common reburn fuel is natural gas, especially for coal-fired boilers.

Reburning can be used with coal, oil or gas as a primary fuel. It has been demonstrated on wall-fired, tangentially fired and cyclone boilers, as well as on both dry- and wet-bottom coal-fired boilers. Reburning does not require any significant operational changes to the primary zone or burners; this is a major advantage with wet-bottom (slagging) boilers.

Natural gas heat input (reburn fuel flow rate) is not more than 20 percent of the total fuel input (on a Btu basis), and is usually between 10 and 15 percent. To date, approximately eight boilers are equipped with natural-gas reburning systems, and proven NOx reduction is 30 to 60 percent.

Fuel-lean gas reburning

With Gas Research Institute (GRI) support, Energy Systems Associates is developing, testing and demonstrating another reburning technology called fuel-lean gas reburning (FLGR), also known as controlled gas injection.

Like conventional gas reburning, FLGR uses natural gas as a reburn fuel that is injected above the primary combustion zone in such way as to maintain the required stoichiometry in the second combustion zone uniformly on a very localized basis. This avoids the formation of a fuel-rich zone and maintains overall fuel-lean conditions across the furnace.

Natural gas is injected in relatively low temperatures (2000°F - 2300°F) using multiple high-velocity turbulent gas jets that penetrate to the areas with the highest NOx concentration. Natural gas reacts as a chemical-reducing agent for the oxides of nitrogen in the upper furnace zone.

FLGR can reduce NOx by 25-35 percent, with natural gas consumption only five to seven percent of total boiler heat input. FLGR equipment can be installed at low capital cost, typically less than $8/kW. It is a potentially cost-competitive option for utilities requiring moderate NOx reduction.

Advanced gas reburning

Energy and Environmental Research Corporation, with GRI support, has developed and tested a NOx control technology called advanced gas reburning (AGR) which combines conventional gas reburning and selective noncatalytic NOx reduction (SNCR). AGR can boost NOx reduction by as much as 85 percent at lower capital cost than comparable alternatives.

In AGR, a nitrogen agent such as ammonia or urea is injected in the upper furnace to reduce nitric oxides to molecular nitrogen. Synergistic AGR, in which overfire air is injected along with the nitrogen agent, enables the system to follow boiler load more closely.

Recently, GRI, Fuel Tech and Energy Systems Associates have developed a combination of Lean-Gas Reburning and SNCR that is called Amine-Enhanced Fuel-Lean Gas Reburn (AEFLGR). The technology is being tested at Pleasant Prairie Power Plant in Wisconsin. It is expected that AEFLGR will be capable for 60-70% NOx reduction with 5-7% natural gas heat input.

Methane de-NOx technology

The Institute of Gas Technology (IGT) has developed methane de-NOx reburning for stoker-fired combustors. In this technology, natural gas is injected just above the solid fuel bed. This not only reduces NOx formed in the solid fuel bed, but also limits its formation, because a significant portion of the NOx precursors is decomposed and reacted to from molecular nitrogen. A reduction in the number of zones and injection levels provides sufficient residence time for reburning and burnout, particularly for retrofit applications.

Methane de-NOx was evaluated on a pilot-scale combustor at Riley Stoker's facility, at the Olmsted County Municipal Waste Combustion facility in Rochester, Minn., and in two incineration plants in Japan. The process was subsequently evaluated on a coal-fired stoker at the Cogentrix Inc plant in Richmond, Va. NOx emissions were reduced by more than 50% with 8% natural-gas injection and by up to 70% with 15% natural-gas injection. In addition, boiler efficiency improved by as much as 2%.

All eight 360 MMBtu/h stoker boilers at Cogentrix were subsequently equipped with the methane de-NOx reburn system, and since September 1998 they have been in continuous operation, maintaining NOx and CO emissions in compliance with Virginia air permit requirements.

IGT's methane de-NOx technology is licensed to Detroit Stoker in the U.S. and to the Takuma Co. in Japan. This technology was awarded a prestigious 1997 R&D 100 Award in the U.S. and an Environmental Prize from the Japan Environmental agency.

Pulverized coal preheat de-NOx burner

IGT, together with its partners, has extended the methane de-NOx technology to deep NOx reduction in the burners and combustion chamber of pulverized coal (PC) burners. This system does not require chemical additives and has low capital and operating costs.

Although the effectiveness and viability of this technology have not been proven, discussions are ongoing with FETC for a demonstration project at a power plant. IGT says the system could be implemented within 18 months.

There are three components to this technology: 1) a gas-fired burner that preheats coal to approximately 1500°F in oxygen-deficient conditions prior to combustion, thus releasing fuel nitrogen and other volatiles present in the coal; 2) low NOx burners with internal combustion staging; and 3) additional natural-gas injection in the primary combustion zone integrated with overfire air in the upper combustion chamber. According to IGT analysis, this system can potentially reduce NOx emissions in PC boilers to less than 0.15 lb. NOx per MMBtu and could be a key enabling technology for the PC plant of the future.

3.2.2 Availability

West Virginia currently has 15,000 miles of natural gas pipelines in place and is the largest producer of natural gas east of the Mississippi River. The pipeline system and abundant source assures that an adequate supply of gas for co-firing purposes can be delivered to existing or new coal-fired power plants.

3.2.3 Technical Issues

Co-firing levels in previous tests have typically ranged from 5-30 percent on a heat-input basis. Tests have been conducted up to and including 100 percent gas firing. Some benefits attributed to gas co-firing are reduced NOx emissions and lower levels of carbon in the fly ash. However, results have not been consistent. NOx reductions may be on the same order as the amount of gas co-fired, or they may be considerably less. Some units have not obtained any additional NOx reduction. Data on carbon in ash is even less consistent, without any discernible pattern.

Burner technology continues to develop, and advances in dual fuel burners will improve the viability of co-firing. Computer modeling can help with burner design and with investigation of heat transfer throughout the boiler.

The safety of gas co-firing may be a concern to those unfamiliar with the technology. Some effort will probably be required to address the concerns of those such as insurance underwriters.

3.2.4 Cost

An important factor in determining the economic viability of gas co-firing is the differential fuel cost between natural gas and coal. For example, if coal costs less than natural gas on a given day, then the difference must be made up for by environmental and economic benefits of co-firing, such as lower SOx and NOx emissions.

Generators will want to gain the maximum benefit from the natural gas consumed. One effect this may have is to favor gas reburn technology over co-firing because of the larger NOx reduction that is obtained with reburn (40-60 percent).

3.3 Tire-Derived Fuel

Co-firing with waste tires is a proven technology used at industrial facilities throughout the nation. In addition to providing a quality fuel, the use of waste tires assists states in attacking a common and persistent solid-waste management problem.

Tire-derived fuel (TDF) offers a BTU value equivalent to or better than coals currently being burned in the region. What surprises some is that co-firing TDF provides environmental advantages over the burning of coal only. Emissions of sulfur dioxide and nitrogen oxide are reduced while co-firing with TDF, as reported in testing by the U.S. EPA. Economics becomes the critical issue in determining when and where TDF may be used.

Although there are no commercial TDF operations to date in West Virginia, Allegheny Power and Capital Cement are both seeking to use TDF in boilers they operate in the state. Allegheny's Willow Island Power Station is located in Pleasants County and Capital Cement's plant is located in Berkeley County.

Allegheny has experimented with using shredded tires as a 10 percent fuel mix with coal. Test burns in recent years have been encouraging, meeting AP's needs and winning the approval of the WV Office of Air Quality. Preliminary results indicate that TDF can be a cost-effective fuel and should allow the plant to reduce its generation cost and increase production.

Capital Cement's system burns whole tires, mixed with coal in a 5-10 percent ratio. Tires are successfully co-fired in cement kilns around the nation. Test burns at Capital have also been successful, and Capital is installing a new fuel delivery mechanism, moving the process closer to commercial operation.

3.4 Other Co-firing Fuels

It is important to recognize other fuels for co-firing, such as petroleum coke, landfill gas, impounded coal fines, municipal solid waste and industrial wastes. Each has its own advantages and concerns, but there have been demonstration projects recently where the most economical option for co-firing was shown to be a blend of "opportunity fuels" such as biomass, tires and/or petroleum coke. Furthermore, gasification and liquefaction of biomass, farm animal wastes and other industrial byproducts may also provide co-firing fuels.

4.0 Conclusions and Recommendations

The task force concludes that environmental regulations, electric industry restructuring and renewable energy portfolio standards offer major opportunities for co-firing in West Virginia. These initiatives could expand opportunities for economic development in the state, increase demand for use of a mixture of co-firing fuels that would enhance coal use in the state's power plants, as well as benefit other industry sectors through utilization of their waste materials.

Commercial implementation of proven co-firing technologies will require a concerted cooperative effort by industry, government and research organizations. The state should seriously consider tax credits and other economic incentives to jump-start this new dimension of West Virginia's energy industry.

The State of West Virginia can play an important role in facilitating co-firing as part of a comprehensive energy strategy. It can be the first state in the nation to face the fuel source problem directly and in a balanced manner. Initial recommendations for state actions relative to co-firing include the following:

- Assuring that co-firing additions that increase a plant's output or improve its compliance do not undergo excessive new source permitting.

- Reviewing all DEP regulations that apply to the use of co-firing fuels and simplifying the process so that companies feel sure their investments will not be stranded by regulations.

- Certifying that green power is part of the energy strategy of West Virginia and that it is in the best interest of the state to encourage co-firing, carbon sequestration, and use of renewable fuels.

- Creating an efficient, user-friendly, one-stop permitting/certification process for co-firing whereby companies can make investment decisions based on economics, environmental issues, and resource development information.

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Appendix 1

Table 3. Savings Realized by Westvaco as a Result of the E-Fuel® Technology

	Previous	Current	Savings
Coal Volume (tons/day)	167	147	20
Coal Price ($/ton)	$41.00	$33.00	$8.00
Total Annual Fuel Cost[1]	$2,464,920	$1,746,360	$718,560
Wet Landfill Costs[2]	$655,200	$0	$655,200
Dry Landfill Costs[3]	$300,000	$0	$300,000
Total Landfill Costs	$955,200	$0	$955,200
Total Project Savings			$1,673,760
Pellet Fee (ton)	$0	$549,500	
Project Financing	$0	$382,900	
Supplied Power	$0	$405,000	
Total Project Costs	$0	$1,337,400	$1,337,400
Total Annual Savings			$336,360

Source: Westvaco Three Rivers Environmental Award Application

Notes:
[1] 360-day per year operation
[2] 100 loads per month x 14 wet tons/load x $39.00/ton x 12
[3] Landfill costs for plastics are $25,000 per month x 12

Table 4. Boiler Emissions Test

Emission	Coal	E-Fuel	Reduction
Particulate	0.027 lb./mm Btu	0.013 lb./mm Btu	51.9%
SO_2	2.35 lb./mm Btu	1.40 lb./mm Btu	40.4%
NOx	0.42 lb./mm Btu	0.34 lb./mm Btu	19.0%

Source: Westvaco Three Rivers Environmental Award Application

Appendix 2

Table 5. Availability of Sawdust, Chips, Bark, Shavings, and Slabs/Edgings/End Trim in West Virginia for 1998 (in tons per week, by county)

County	Sawdust	Bark	Chips	Shavings	Slabs/ Edgings/ End Trim	Total
Barbour	175	220	120	15	12	542
Boone	250	108	400	---	---	758
Braxton	450	265	125	---	---	840
Calhoun	120	120	200	---	---	440
Clay	295	212	380	---	---	887
Doddridge	155	155	315	---	---	625
Fayette	100	100	150	---	---	350
Gilmer	40	---	---	---	60	100
Grant	72	---	1091	---	---	1163
Greenbrier	836	340	---	---	200	1376
Hardy	54	---	50	---	5	109
Jackson	200	75	300	---	---	575
Jefferson	32	---	25	---	3	60
Kanawha	200	150	437	---	---	787
Lewis	140	90	200	---	---	430
Mason	140	80	120	---	---	340
Mercer	284	215	546	---	60	1105
Mineral	---	500	---	---	---	500
Mingo	926	750	1425	---	---	3101
Nicholas	608	400	773	---	---	1781
Pocahontas	753	745	1103	---	2	2603
Preston	731	676	1290	---	20	2717
Randolph	1354	304	508	---	6	2172

Ritchie	400	290	530	---	---	1220
Roane	10	50	70	---	70	200
Summers	100	25	231	---	---	356
Tucker	164	110	174	---	---	448
Upshur	288	1657	50	---	388	2383
Wayne	10	---	---	---	40	50
Webster	41	---	---	---	8	49
Wetzel	175	65	150	---	---	390
Wood	---	140	---	---	---	140
TOTAL	9,103	7,842	10,763	15	871	28,597