Co-firing biomass with coal.

Balancing US carbon objectives, energy demand and electricity affordability.

Co-firing uses existing power generation assets, while mitigating the cost of carbon.

For more information, call Kevin Sullivan or Ronald Meijer at KEMA, Inc. at: +1-800-892-2006 or visit:
http://www.kema.com/consulting_services/power_generation/sustainable_and_distributed_energy/bio_energy/cofiring_biomass/

Table of Contents

1. Introduction

According to the World Coal Institute, coal generated about half of the electricity in the United States in 2006. With over 50,000 plants worldwide and growing, demand for and production of coal-based electricity continues to increase. In fact, according to the International Energy Agency, the world's power demands are expected to rise 60 percent by 2030, with fossil fuels (including coal) accounting for 85 percent of the energy market.

Coal-based electricity production has been linked to global warming, and is responsible for a large portion of carbon dioxide emissions worldwide. Many organizations are concerned about the environmental impact of burning fossil fuels, and coal in particular. Scientists have warned such pollution must be reduced to avert the most serious consequences of climate change. This concern has resulted in new energy and environmental policies aimed at reducing emissions worldwide. Over time, these policies and regulations are likely to become more stringent.

Interest in co-firing biomass (plant matter) with coal to generate electricity has grown, as co-firing directly decreases fossil greenhouse gas and sulfur emissions over burning coal alone. Co-firing enables electricity producers to meet regional and global greenhouse gas (GHG) and renewable portfolio standard (RPS) targets for their generation assets, and presents an opportunity to address the emerging carbon dioxide credit market.

Co-firing makes use of existing power generation assets with relatively low modification costs, while providing a means to mitigate the cost of carbon. Low cost co-firing applications are those in which plant operators simply mix biomass feedstock with coal without modifying the boilers. The capital costs are simply those required to receive and handle the biomass fuel. High cost co-firing applications can require significant modifications to boiler systems due to upgrades in fuel handling equipment and burners. These allow a far greater level of co-firing. Many national governments provide tax and financial incentives to encourage electric producers to adopt co-firing.

2. Understanding Co-firing

Biomass co-firing is a proven technology. Many coal plants have been converted or retrofitted to accommodate co-firing with limited impacts to efficiencies, operations, or lifespan. However, there is much more to co-firing than simply adding a secondary fuel. A power producer wishing to introduce bio-fuel at a plant must address complex technical, logistic, economic, and environmental considerations. A thorough analysis must answer questions such as:in which coal-fired units is co-firing technically and economically feasible? How will co-firing influence boiler and plant performance and integrity? What about flue gas treatment performance, especially the selective catalytic reduction unit? Which co-firing fuels are available and economic to co-fire? What is the best ratio of biomass to coal? What happens to ash composition and sale-ability? Are the capital costs justified by economic and environmental benefits? Will emissions and by-product quality stay within the required limits?

Not all plants can or should be converted to co-firing production. There are risks involved, and options for managing them. Working with experts experienced in the global biomass field is important.

2.1 Co-firing Project Phases

In general, the following are the steps to considering and implementing a co-firing project:

- ***Fleet/multiple unit screening*** – The generation portfolio is reviewed, including conventional and renewable energy sources, to benchmark GHG emissions. Units that can most contribute to the company's climate action plan when co-firing with RPS eligible biomass are identified.

- ***Fuel supply study*** – Reliable co-firing is contingent upon the supply and characteristics of biomass. This study identifies options for a secure, predictable supply from source to the power plant stockpile. Also, pre-processing of woody biomass (such as pelletizing) can strengthen the supply infrastructure and reduce transportation costs; these options are investigated.

- ***Preliminary technical/economic assessment*** – The preliminary assessment looks at the power plants suitable for co-firing. An initial ranking is performed – based on location, transport and storage infrastructure, boiler design layout and size – while considering economics.

- ***Detailed technical/economic assessment*** – The detailed assessment further analyzes the ranked set of power plants technically and economically, taking into consideration the detailed design, characteristics, operating experience, and configuration to further refine the return-on-investment and technical changes required.

- ***Conceptual design*** – This phase provides a high level design for a specific plant, including the overall plant architecture and layout plans. The biomass injection route is selected during this phase.

- ***Detailed design*** – The detailed design includes an analysis of technology and equipment suppliers, details all interface points and provides work scope packages to perform the adaptation to co-firing.

- ***Implementation*** – This phase provides the project management and governance programs to ensure a successful project.

- ***Operation and monitoring*** – In this phase, the project is fully implemented, and now the fine-tuning is performed with appropriate diagnostics and calibration. Also, a corrosion monitoring and prevention program is established.

2.2 Technical Considerations

In general, there are four alternative approaches to injecting biomass into the generation process. Each approach targets different parts of the process, as shown in Figure 1.

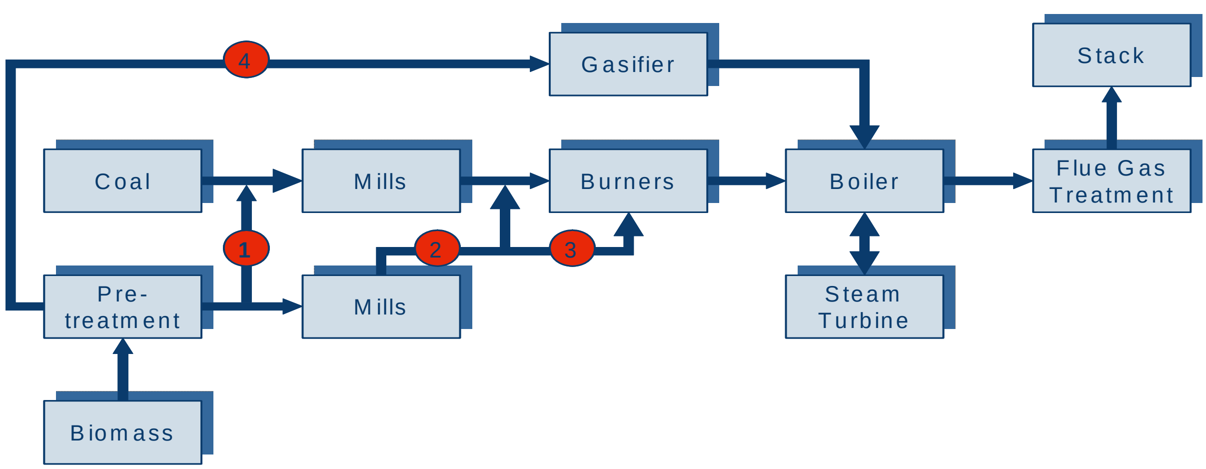

Figure 1. Alternative Co-firing Approaches

These approaches can be summarized as follows:

- *Approach 1* blends the coal/biomass mixture on a conveyor belt and co-mills the fuel mixture in the existing coal pulverizers, then combusts in the existing coal burners.

- *Approach 2* separates biomass pre-processing (milling and drying), followed by injection of the biomass in the pulverized fuel lines (after the pulverizers) and simultaneous biomass/coal combustion in the original or modified coal burners

- *Approach 3* separates biomass pre-processing and feeding and combustion in separate, dedicated biomass burners.

- *Approach 4* provides for indirect co-firing of biomass; for example, through an upfront gasifier with co-combustion of the (cleaned) fuel gas in the main coal-fired boiler.

Each of these approaches has its own unique operational requirements, limitations and constraints, and puts specific demands on both the fuel quality and the achievable biomass percentage. The technical assessment should detail all relevant constraints and subsequent measures to be taken for a desired co-firing configuration. Specific constraints to be addressed include:

- Permitting requirements, specific site restrictions
- Fuel type, availability and quality
- Storage capacity, required road/rail movements, fuel logistics
- Required fuel handling, pre-processing (drying, milling)
- Pulverizer capacity and performance
- Burner arrangement, available space in the boiler house
- Possibilities for injecting biomass into the boiler
- Boiler performance, steam conditions, net power output, re-powering options
- Existing boiler limitations
- Corrosion, slagging, fouling propensity
- Flue gas cleaning operation and performance
- Emissions constraints
- Ash quality requirements
- Health and safety aspects

2.3 Regulatory & Environmental Considerations

Regulatory and environmental considerations include current and expected upcoming renewable energy policies, carbon dioxide emission-reduction targets, tax incentives, and new legislation with respect to waste disposal. Such considerations usually have cost consequences, and should also be addressed in the economic assessment.

The reduction of greenhouse gas emissions is increasingly a hot topic. Policy options include those which:

- Reduce demand, by encouraging energy efficiency and providing for advanced metering/demand response;
- Lower carbon supply, through use of utility and distributed generation renewables; and
- Encourage the development and use of new technologies, through R&D investments, standards, and push/pull market strategies.

Chances are very good that a greenhouse gas cap and trade bill will be enacted by the U.S. federal government by 2010. The cap and trade concept was developed in the 1990s as a means to control acid rain by making emissions a tradable commodity. By allocating permits for the emission of greenhouse gases subject to limits and monitoring, emitters with surplus allowances can trade with emitters in need of allowances. The EPA is likely to develop its own requirements, as will states and regions.

2.4 Economic Considerations

An economic assessment considers the cost of biomass from identified fuel supplier(s), coal costs, required capital for co-firing installation, ongoing operations and maintenance costs, and the corporate finance model (weighted average cost of capital, tax rate, inflation, etc.). The assessment should account for various "what if" scenarios.

Environmental taxes and credits, and the cost of meeting renewable portfolio standards are also considered. The assessment can also consider: benefits from reduced sulfur dioxide, nitrogen oxide, and/or mercury emissions; reduced ash landfill costs or income from ash applications;

renewable energy certificates (RECs); and production tax credits (PTCs). The cost of emitting carbon should be assessed against the cost of breaking even with biomass.

From a discounted cash flow analysis, the net present value and internal rate of return should be determined. This together with a sensitivity analysis on relevant parameters provides a good basis for evaluation of the economic potential of various co-firing configurations for a specific coal-fired unit.

3. A History of Co-firing

Biomass co-firing has been used in Europe and the Netherlands in particular for over a decade. Full scale commercial co-firing of at least 10 percent biomass (based on heat input) is a daily practice, with a wide variety of bio-fuels and co-firing configurations.

While the technology has been demonstrated in many boiler types, the U.S. has been slow to adopt biomass co-firing due to its limited full scale commercial use, a lack of incentives, and a general reluctance in introducing new fuels into boilers. However, power generation and co-generation from biomass, waste, and recovered fuels is now quickly becoming a hot topic for the power sector as a result of new environmental policies and regulations.

Since 2003, KEMA, a major international energy consulting firm, has been working with North American utilities in order to determine short-term strategies for the introduction of biomass into their existing coal-fired units. Long-term strategies are being developed to ensure these utilities are prepared for likely upcoming regional or national carbon dioxide reduction regulations.

KEMA has examined the opportunity that co-firing provides in improving the operation of older units, increasing efficiency and optimizing use of assets, all while supporting environmental regulations. For this purpose, KEMA has supervised regional biomass supply studies and plant assessments, in which the technical possibilities and constraints of various co-firing routes have been assessed. By then applying economic analyses – assessing net present value, internal rate of return, and applying sensitivity analysis – based upon conceptual design and investment costs of pre-treatment and co-firing installations, KEMA has ranked alternative co-firing approaches. This techno-economic ranking takes into account various fuel types and properties, co-firing percentages, technical realization, and identifies viable opportunities for the utilities in biomass utilization.

4. Conclusion

Biomass co-firing is gaining increasing attention from both utilities and regulatory stakeholders as it offers renewable energy generation with low capital costs, and takes advantage of the high electrical efficiencies of today's coal power plants. By replacing up to 20 percent of the coal fuel with biomass, a substantial volume of carbon dioxide emissions may be avoided. Sulfur dioxide and nitrogen oxide emissions usually decrease as well, due to the different chemical composition of biomass. Co-firing may indeed make sense, from cost and environmental perspectives, for many coal-based electricity producers. Many electricity producers opt to conduct trials first, to prove the viability, reliability, sustainability and cost-effectiveness of bio-firing in their plants. It is important to work with experts in exploring this possibility.

In North America, KEMA has performed extensive feasibility studies on co-firing for six large utilities and is currently expanding this to the actual implementation of co-firing installations based upon the results from these studies. Over the past 15 years, KEMA has gained extensive experience with direct and indirect co-firing of several biomass fuel types. KEMA has tested co-firing mixtures of coal and biomass fuels up to about 25 percent and has been involved with more than 50 small and full-scale biomass trials.

KEMA's hands-on experience has resulted in deep knowledge about both short-term and long-term operational aspects related to co-firing, including: storage and spontaneous combustion, quality of fly ash, boiler performance, effect on flue gas equipment (FGD, SCR), mill performance, emissions, fuel handling, and corrosion and erosion. Having designed and implemented many co-firing plants, KEMA has extensive operational, maintenance and management know-how, and insight into associated risks and issues associated with converting to biomass co-firing.

KEMA has a staff of more than 20 professionals experienced in and dedicated to co-firing projects.

Case Study

KEMA recently supervised a fuel supply study, and provided a detailed techno-economic assessment, and conceptual design for American Electric Power (AEP), a U.S. public utility holding company. The plant featured an 800 electrical megawatt (MWe) opposed wall pulverized coal-fired boiler; the base load unit. The plant was firing low sulfur Eastern bituminous coal, but after a flue gas desulfurization unit was installed in 2008, it was switched to high sulfur coal, with four to seven pounds sulfur dioxide per one million BTU. The plant had a selective catalytic reduction unit and cold-side electrostatic precipitator installed.

Objectives

AEP plant operators desired to co-fire between five and ten percent biomass (by heat input) with the following conditions: a separate injection of biomass, the ability to operate at 100 percent coal, no unit de-rating, no severe adverse operating conditions, no degradation of ash quality, no increased emissions, compliance with regulation and legislation, broad initial fuel scope, and competitive economics/a favorable internal rate of return.

Fuel Supply Study

A fuel supply study was conducted to identify biomass fuel supply types, key suppliers, available biomass quantities by type, biomass costs (freight on board and/or delivered), biomass characteristics, transportation issues, seasonal issues, and contract terms or conditions.

Findings of the fuel supply study were: a significant amount of clean wood is available, mostly wood chips from saw mills; little waste wood available, many untouched sources (thinnings, toppings, etc.); competing markets present; agricultural streams too expensive; 14 of the most economic suppliers required five percent (e/e) biomass; and high transportation costs.

A fuel scenario based upon a mix of sawdust and wood chips was selected.

Technical Assessment

The technical assessment examined fuel availability and quality; storage capacity, requirements, and logistics; required fuel handling; existing boiler limitations; impacts on boiler performance, steam conditions, emissions, ash quality, corrosion, slagging and fouling propensity, and flue gas treatment performance; unit operation capacity (pulverizer, fans, etc.), co-firing configuration, and permit requirements.

KEMA used its proprietary Cofiring Control Model software to provide immediate quantitative insight in the risks associated with firing a mix of fossil and/or biomass fuels in coal-fired power plants. The software features a boiler-specific module for calculating unburned carbon, emissions and by-product quality, as well as temperature and flue gas composition profiles. It also has a fouling and slagging module. It also has a database with specific fuel specifications, and provides corrosion propensity calculations. The model addresses environmental and permit constraints.

The sawdust and wood chips, with up to 50 percent (by weight) moisture, would be delivered by truck, ten hours per day, six days per week. The co-firing operation would take place 24 hours per day, seven days per week. Redundancy would be n+1, with four days of biomass storage.

The pre-processing plant would have two stage milling and intermediate drying and storage. Injection would be through the process flow lines or dedicated biomass burners. The process flow is diagrammed in Figure 2. The biomass handling plant layout appears in Figure 3.

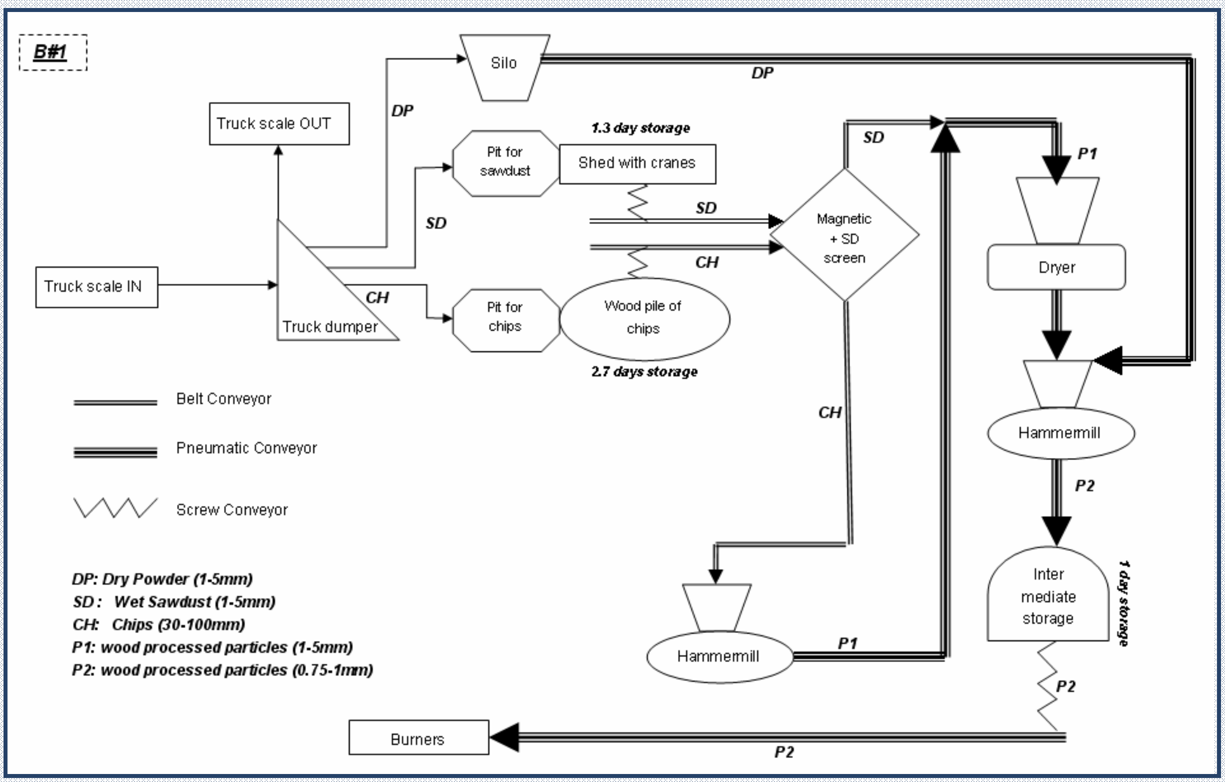

Figure 2. **Process Flow Scheme**

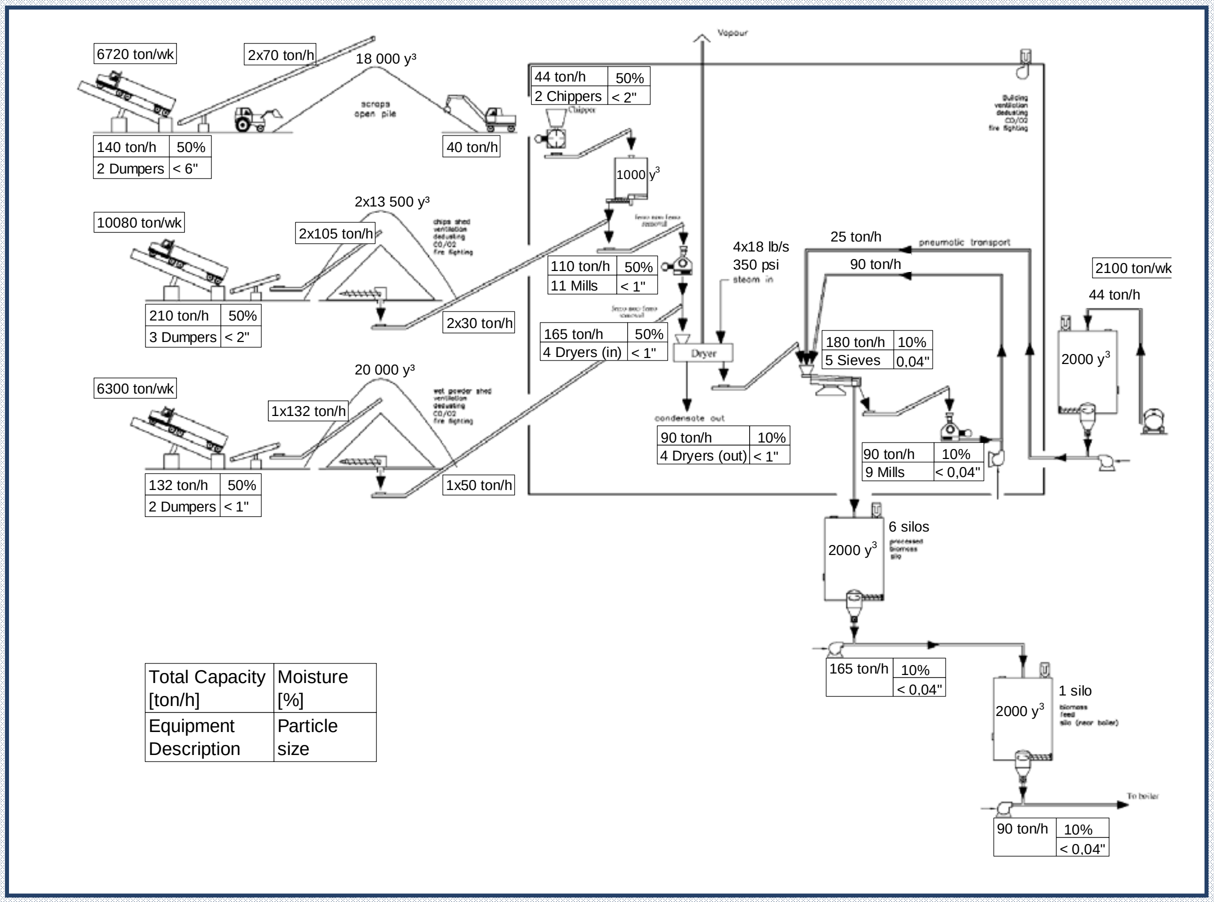

Figure 3. **Layout of Biomass Handling Plant**

Several cases were examined for to assess boiler performance using thermodynamic modeling in KEMA's Cofiring Control Model software. Variables examined included flue gas flow and temperature, the furnace oxygen profile, steam temperatures, carbon burnout (LOI), ash composition, emissions, and slagging, fouling, and corrosion propensity. The cases examined are shown in Table 1.

Case	Description
I	Current case – 100% coal firing; low sulfur coal
II	Post FGD: 100% coal firing; high sulfur coal
III	3.3 percent (e/e) co-firing through middle deck burners
IV	6.6 percent (e/e) co-firing through middle deck burners
V	9.3 percent (e/e) co-firing through dedicated burners (height middle deck)

Table 1. **Boiler Performance Case Studies**

Results of the case analysis are presented in Table 2 and Figure 4.

Parameter	Current	Post FGD	3.3 %	6.6%	9.3 %
Flue Gas Flow (lb/s)	2020	2047	2042	2038	2035
Furnace Exit Temperature (degrees F)	2520	2562	2563	2564	2564
Unburned Carbon in Ashes (LOI) (%)	3.72	3.65	3.88	4.12	4.32

Table 2. Case Study Results

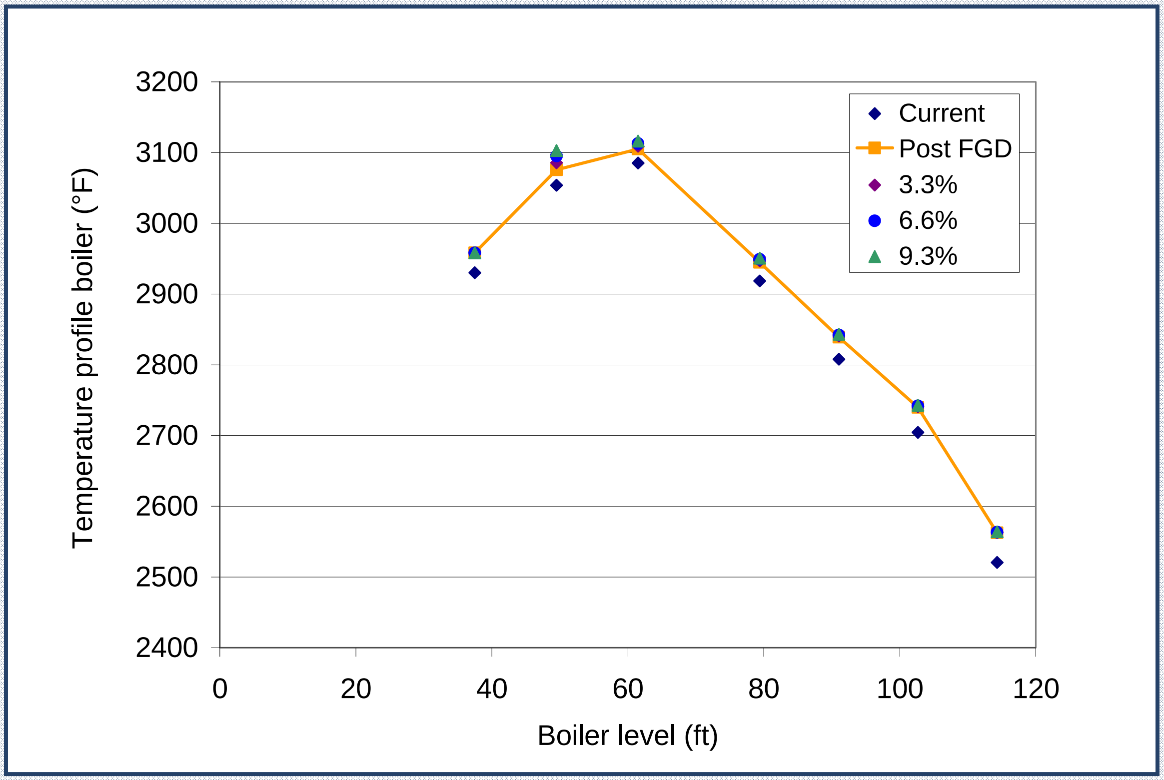

Figure 4. Boiler Temperature Profile (Degrees F)

Economic Assessment

The economic assessment examined five scenarios against the following parameters: biomass and coal prices; capital requirements, and operations and maintenance costs; carbon dioxide and sulfur dioxide costs; load factor; heat rate; operating period; and interest rate, weighted average cost of capital, tax rates, and inflation.

The five cases were:

Case	Description
1	3.3 percent (e/e) co-firing, process flow lines, sawdust
2	4.65 percent (e/e) co-firing, dedicated burners, sawdust
3	6.6 percent (e/e) co-firing, process flow lines, sawdust and chips
4	9.3 percent (e/e) co-firing, dedicated burners, sawdust and chips
5	9.3 percent (e/e) co-firing, dedicated burners, sawdust and chips and scraps

Table 3. Economic Assessment Case Studies

It initially appeared that Case 3 was optimal. Sensitivity analyses conducted examining capital, biomass, and carbon dioxide costs against net present value/internal rate of return. Break even versus actual biomass costs were then assessed across the five cases. A net present value sensitivity analysis was then conducted across key parameters.

The economic assessment found:

- Firing up to 10 percent (e/e) biomass is technically feasible: there is enough clean biomass available, a suitable area for the pre-processing unit, no unit de-rating, and no undue degradation of combustion properties.
- The most important economic parameters are: biomass and coal prices, specific capital outlay costs, and the carbon dioxide price.
- Break even is at a biomass price without any carbon tax of between $1.7 to 2.1 dollars per million BTU.