Georgia Department of Natural Resources

Environmental Protection Division • Air Protection Branch
4244 International Parkway • Suite 120 • Atlanta • Georgia 30354
404/363-7000 • Fax: 404/363-7100
Noel Holcomb, Commissioner
Carol A. Couch, Ph.D., Director

JUN 17 2008

Mr. Mark S. Sajer
Managing Director
Summit Energy Partners, LLC
99 Summit Avenue, Suite 2C
Summit, New Jersey 07901

Re: PSD Application No. 17700 dated September 27, 2007
Yellow Pine Energy Company, LLC (Yellow Pine) Fort Gaines, Georgia (Clay County)

Dear Mr. Sajer:

Technical review of the above referenced application for the construction and operation of a 110-megawatt (MW) power plant has begun. As a result, the Division has the following comments:

Background

The facility, as currently proposed, would be a 110-megawatt (MW) power plant. The facility is proposed to include: bubbling fluidized bed boiler (BFB) with a heat input capacity of 1,529 million Btu/hr; a condensing steam turbine generator; an auxiliary boiler; multi-cell mechanical draft wet cooling towers; a water treatment plant; a wastewater treatment plant and outfall; back-up emergency diesel generator and diesel firewater pumps; ash/inert landfill; aqueous ammonia storage tanks; limestone storage bins; fuel oil storage tank(s); and supporting plant equipment. The primary fuel from the BFB is biomass. In addition to biomass, the plant will have the capability of firing bituminous coal, petroleum coke (Pet Coke), or 95% metal-free tire-derived fuel (TDF) in small quantities. Low sulfur No. 2 fuel oil or propane would be used for start-up of the fluidized bed boiler(s) and would be the primary fuel of the auxiliary boiler.

The original application (No. 17700) was dated September 27, 2007 and is a very lengthy document. In addition, EPD has received the following application supplements: November 30, 2007 (~ 46 pages), January 18, 2008 (~19 pages), and April 18, 2008 (~ 24 pages). EPD has consistently maintained a web page for all application related documents at:
http://www.georgiaair.org/airpermit/psd/dockets/yellowpine/.

The facility, as currently proposed, would have the following potential emissions[1]:

Pollutant[2]	Emissions
NOx	670 tpy
SO2	670 tpy
VOC	134 tpy
PM10	222 tpy
CO	2009 tpy
Total HAPs (based on biomass only)[3]	231 tpy

[1] Page 4-4 of January 18, 2008 application supplement.
[2] This list is not intended to be exhaustive of all emissions from the facility.

In addition to the Air Permit that is required, we note that the facility needs a Water Withdrawal Permit for approximately 2 million gallons per day, a Water Discharge Permit for about 260,000 gallons per day, a permit for the Landfill that will be located onsite.

BACT - General

As a preface to the following discussion on the BACT proposal for the NSR regulated pollutants subject to BACT, I want to first address the definition of BACT in the regulations, the issue of the technical feasibility of controls, and the basis for determining achievable BACT limits.

The PSD regulations define BACT as:

> "an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the [Director], on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant…."

Air pollution control technologies that are not technically feasible for the proposed source may be eliminated from further consideration for BACT. The EPA NSR Workshop Manual has a good description of what documentation is needed to determine that a particular technology is not technically feasible.

> "A demonstration of technical infeasibility is based on a technical assessment considering physical, chemical and engineering principles and/or empirical data showing that the technology would not work on the emissions unit under review, or that unresolvable technical difficulties would preclude the successful deployment of the technique. Physical modifications needed to resolve technical obstacles do not in and of themselves provide a justification for eliminating the control technique on the basis of technical infeasibility.[4]"

The EPA NSR Workshop Manual[5] includes a discussion of the types of information that should be used to provide the basis for the BACT emission limit.

> "Manufacturer's data, engineering estimates and the experience of other sources provide the basis for determining achievable limits…. [T]he basis for choosing the … level (or range) of control in the BACT analysis must be documented in the application.[6]"

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[3] Total HAP emissions were not provided for the scenarios with supplemental fossil fuel and could be higher.
[4] Pg. B.20 of NSR Workshop Manual.
[5] EPD notes that the NSR Workshop Manual is guidance and is not a legally enforceable document. However, it is acknowledged to be a good source of guidance in many respects.
[6] Pg. B.24 of NSR Workshop Manual.

As a general matter of concern, our review of your application has shown that the basis for choosing the proposed level of control in the BACT analyses is not well documented. The remainder of this letter goes into specific detail on some of the pollutants, but we would like you to revisit all the NSR regulated pollutants that are subject to BACT to ensure that your application includes the necessary level of documentation. As you do this, please keep in mind that each BACT emission limit should be accompanied by a proposed averaging time, compliance determination method, monitoring, and record keeping to ensure that the BACT emission limits are practically enforceable[7].

BACT – Clean Fuels for BFB

The application asserts that the facility can not burn only biomass in the boiler. It says that coal, pet coke, and/or TDF are needed to ensure safe operation of the boiler. Specifically, the application states:

> "During startup and in cases of wet or low BTU content fuel, a supplemental fuel is required to stabilize the boiler combustion and prevent an explosion.[8]"

The use of fossil fuels such as coal and pet coke contribute significantly to the potential emissions from the proposed facility. They are the source of most of the sulfur dioxide emissions and sulfuric acid mist emissions. They also contribute to the nitrogen oxides emissions and certain hazardous air pollutants, including mercury[9]. Other than the short description shown above, the application contains very little documentation to support the position that fossil fuels are required in this boiler to ensure safe operation. EPD requests more information to support this position. Specifically, EPD has the following questions:

1. Is this is an issue with all BFB boilers, or just the one that your are proposing? If it is an issue with all BFB boilers, does that mean that there are no BFB boilers, operating or proposed, in the United States that burn only biomass?
2. EPD recently issued a draft air permit to Green Energy Partners, LLC (Plant Carl)[10]. This facility has proposed a 400 MMBtu/hr bubbling fluidized bed (BFB) boiler firing a combination of chicken litter and woody biomass. It would not burn any fossil fuels. Biodiesel fuel, waste cooking oil, grease, or animal fat will be used for starter fuel. I did note that the average heat content of the fuel reported by Plant Carl is 5,100 Btu/lb while the average heat content of the fuel you have reported in your application is 4,350 Btu/lb. Nonetheless, we would like an explanation as to why Plant Carl can operate their BFB with no fossil fuels and you can not.
3. Babcock & Wilcox has produced a product brochure in which they state that the BFB is "Superior to other technologies for burning wet wood-based fuels – between approximately 2800 and 3500 Btu/lb HHV (6513 and 8141 kJ/kg) without support fuels." A copy of this brochure is attached to this letter. This statement from Babcock & Wilcox seemingly contradicts your claim that "supplemental fuel is required to stabilize the boiler combustion and prevent an explosion." We request that you explain this seeming contradiction.
4. If it is determined that supplemental fuel must be permitted in order to ensure safe operation of the boiler, could you do this without using any fossil fuels (coal, fuel oil, propane, Pet Coke)?

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[7] See Pg. B.56 of NSR Workshop Manual.
[8] Pg. 2 of the January 18, 2008 letter, and see also Pg. 2-4 of the original application.
[9] This contribution to HAP emissions is discussed further in this letter regarding the 112(g) Case-by-case MACT requirement.
[10] This draft permit and supporting documents are available for review on our web page.

  a. Could you handle and store your primary source of fuel (wood) to ensure that the boiler combustion would be stable (with similar startup fuels as proposed by Plant Carl)?
  b. If item (a) is not feasible, could you supplement with non-fossil fuels only (such as biodiesel, TDF, or higher quality wood biomass).
  c. Regarding TDF, the permit application states that the TDF would have a sulfur content of approximately 1.3%. During our meeting of June 4, 2008, you stated that the actual sulfur content would be much higher, possibly higher than 5% (by weight). We request that you provide fuel specifications from at least one of your likely TDF providers and we request that you confirm the expected average and maximum sulfur content of the TDF that you request EPD to consider as part of your application.

5. Finally, if it is determined that Pet Coke and/or bituminous coal is needed as a supplemental fuel to ensure safe operation of the boiler, you should consider if any such fuels with a lower sulfur content are technically feasible. In particular, we are very skeptical of your claim that Alabama coal has a sulfur content of 5%.

<u>BACT – SO2 (and Sulfuric Acid Mist) from BFB</u>

We note that you have proposed a BACT emission limit of 0.10 lb/mmBtu on a 30-day average based on 15% (by heat input) coal or Pet Coke (and 0.19 lb/mmBtu on 3-hour average and 0.13 lb/mmBtu on a 24-hour average). We also note that the emission limit is higher than the 100% PRB coal scenario for the proposed Longleaf coal-fired power plant (0.065 lb/mmBtu). As discussed in the BACT – Clean Fuels section of this letter, we believe additional documentation is needed as to why the high sulfur coal and Pet Coke should be allowed under BACT. Should you still conclude that these fuels are BACT, you should provide manufacturer's data and/or engineering estimates to show the amount of SO2 control in the boiler followed by the amount of SO2 control provided by the scrubber.

As part of the basis for the proposed BACT emission rate, on Pg. 6-23 of the application the following statement is made:

> "The lowest permitted SO2 emission rate for a coal-fired FB boiler in the RBLC using lime spray scrubbing technology is 0.22 lb/MMBtu. The lowest permitted SO2 emission rate for a biomass-fired boiler using lime spray scrubbing technology in the RBLC database is 0.10 lb/MMBtu."

We believe that there are coal-fired FB boilers that have been permitted with emission rates less than 0.22 lb/mmBtu. For example, the Deseret Permit issued by US EPA has a SO2 BACT limit of 0.055 lb/mmBtu.

Table 4.1 of the application shows the maximum hourly emissions for the BFB to be 0.06 lb/mmBtu and 91.7 lb/hr for 100% biomass combustion. This seems too high for 100% biomass combustion since the biomass should contain very little sulfur. We request that you submit additional documentation to support this emission rate.

The application concludes that wet scrubbers are technically feasible, and does include an economics analysis. However, the economics analysis does not include the total (aka average) cost effectiveness of the technology. We request that you submit the total cost effectiveness of the wet scrubber, including documentation to support all the assumptions used in the calculations.

BACT – PM10 from BFB

Page 6-19 of the application contains the BACT conclusion for PM10. It says:

> "There are numerous examples of projects where fabric filter baghouses have been permitted as BACT with emission rates in the range of 0.010 – 0.25 lb/MMBtu. Additionally, the Longleaf Energy Associates pulverized coal boilers were recently permitted with fabric filter baghouses as BACT with an emission rate of 0.033 lb/MMBtu. The proposed BACT for the FB boiler is fabric filter baghouses capable of achieving 99 percent removal and a PM-10 emissions of 0.033 lb/MMBtu."

As an initial matter, I must point out that the PM10 BACT limit for the pulverized coal-fired boiler in the Longleaf Energy Associates permit is 0.012 lb/mmBtu for filterable particulate matter and 0.30 lb/mmBtu for total particulate matter.

Recently, on June 10, 2008, NACAA released a document titles, "Reducing Hazardous Air Pollutants from Industrial Boilers: Model Permit Guidance - June 2008." The executive summary of this document includes the following summary:

> "Reducing Hazardous Air Pollutants from Industrial Boilers: Model Permit Guidance is intended to provide state and local air pollution control agencies with important tools for regulating hazardous air pollution from the approximately 3,000 industrial, commercial and institutional boilers and process heaters (ICI Boilers), ranging from refineries and paper mills to manufacturing plants, operating in every state in the country."
>
> "NACAA published Permit Guidance in response to a June 2007 decision by the U.S. Court of Appeals (Natural Resources Defense Council v. EPA, No. 04-1385) vacating rules promulgated by the U.S. Environmental Protection Agency ("EPA") under Section 112 of the Clean Air Act ("CAA") establishing emission limits for hazardous air pollutants ("HAPs") for these facilities. When EPA fails to meet a deadline for establishing limits under section 112 of the CAA (or where the Court vacates a rule), state and local permitting authorities are required under section 112(j) – the "hammer provisions" – to set the limits for the affected facilities on a case-by-case basis. These limits must be based on the use of the Maximum Achievable Control Technology ("MACT") and may not be less stringent than the MACT floor, defined as the average of the best performing 12 percent of sources in the industrial category."

The document goes on to offer guidance on setting MACT emission limits for coal and wood-fired industrial boilers. It suggests a limit in the range of 0.008 - 0.012 lb/mmBtu for existing coal-fired boilers and 0.01 - 0.02 lb/mmBtu[11] for existing wood-fired boilers. It is important to note that these suggested emission limits are based on the MACT floor (average of best 12% of sources in the category) and are not based on the level of control for the best controlled similar source as would be required for a new source subject to case-by-case MACT review under Section 112(g).

BACT – Feasibility of Oxidation Catalyst for CO

Page 6-31 of the application has the conclusion that catalytic oxidation is not technically feasible.

[11] The recommended limits are believed to be for filterable particulate matter only.

> "Catalytic oxidation is generally utilized for CO emission reductions on non-combustion CO sources. Catalytic oxidation has not been demonstrated and is not commercially available for use on fluidized bed boilers. In addition, catalytic oxidation is not listed as a control for CO emissions from fluidized bed boilers in the RBLC database. Therefore, catalytic oxidation is considered technically infeasible and will not be considered further in this application."

However, catalytic oxidation was found to be technically feasible for the Plant Carl project in Georgia. In fact, they have agreed to use it and have estimated CO control of about 25 to 50%. The applicant determined that the oxidation catalyst could be installed in the exhaust in a location downstream from the electrostatic precipitator (ESP). The ESP will minimize particulate loading and is expected to alleviate the concerns over plugging, slagging, and contamination. We request that you revisit your conclusion that catalytic oxidation is not technically feasible and provide additional documentation should your conclusion remain unchanged. If you do determine that catalytic oxidation is technically feasible, then we request that you submit an economics analysis of the technology. Please include in your analysis a discussion of the amount of VOCs that would be controlled by the technology, including the amount of volatile organic HAPs.

<u>BACT – CO from BFB</u>

Pg. 6-32 of the permit application contains the following conclusion regarding the proposed CO BACT emission limit.

> "There are numerous examples of biomass projects where combustion control has been permitted as BACT with emission rates in the range of 0.28 – 0.63 lb/MMBtu. BACT for CO emissions control is the application of combustion controls with an emission limit of 0.30 lb/MMBtu.[12]"

EPD recently released a draft permit for a BFB that would burn woody biomass and chicken litter to a facility called Plant Carl. This draft permit included a CO limit under the 112(g) case-by-case MACT program of 0.149 lb/mmBtu on a 30-day rolling average. In addition, EPD is reviewing another application for a biomass power plant by Greenway which includes a stoker boiler with a CO emission rate of 0.079 lb/mmBtu[13].

In the recently released NACAA Permit Guidance, NACAA recommended 100 -150 ppm (0.08 - 0.12 lb/mmBtu) for wood-fired boilers. As mentioned earlier with regard to particulate matter emissions, it is important to note that these suggested emission limits are based on the MACT floor (average of best 12% of sources in the category) and are not based on the level of control for the best controlled similar source as would be required for a new source subject to case-by-case MACT review under Section 112(g).

<u>BACT – Feasibility of SCR for NOx</u>

You determined that a Selective Catalytic Reduction (SCR) system would not be a feasible NO_x emissions control option to install on the BFB due to the potential of plugging from the dust in the flue gas (in a high dust SCR application). You also concluded that if a particulate matter control device

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[12] No averaging time was specified.

[13] No averaging time specified, but it should be assumed to be a long term average. This is an emission factor to be a minor source and to avoid PSD review.

were used to alleviate the plugging concern that the flue gases would be too cold for an SCR system and the flue gases would need to be reheated, thus making the cost of control much too expensive (while not mentioned in your application, the use of this fuel could also be considered an adverse energy and environmental impact)[14]. Then, during our meeting on June 4, 2008, you raised a new issue. You stated that the outlet of the BFB would be too cool for SCR and would require the flue gas to be reheated even if plugging were not a concern. This came up when EPD asked you if a hot-side ESP could be used to reduce the potential for plugging before the SCR.

EPD agrees that reheating the flue gases with additional fuel would make the cost of control excessive and we believe that the impacts from the additional energy usage and emissions (from the additional fuel combustion) would be adverse impacts in this case. However, we do request that you provide additional documentation as to why a high dust SCR is not technically feasible due to plugging issues. As mentioned previously in this letter, Babcock & Wilcox has produced a BFB brochure. Regarding SCR, this brochure states, "Because of good carbon burnout, a selective catalytic reduction (SCR) system can cost-effectively be located before dust removal equipment to further reduce NOx."

We also request that you provide additional documentation as to why a hot-side ESP, or any other air pollution control device, could not be used to alleviate the plugging concerns while allowing the flue gases to remain hot enough to be used in a SCR system. If such a scenario is technically feasible, then we request that you conduct the appropriate economics analysis of that system and incorporate that system into the top-down analysis for NOx.

Should you end up doing another economics analysis for SCR based on one, or more, of the scenarios above, we request that you consider the following issues when doing the analysis. EPD believes that be supervisory labor costs and overhead and administration costs associated with the operation of a SCR system are minimal and should be excluded from the analysis. According to page 2.45 of the EPA Air Pollution Control Cost Manual (Sixth Edition), supervisory labor costs should be rather minimum and almost nonexistent since the operation of a SCR would not require the addition of specific personnel to monitor its performance. In addition, as with the supervisory labor costs, page 2.48 of the EPA Air Pollution Control Cost Manual (Sixth Edition) indicates that overhead and administration costs associated with the operation of a SCR system should be minimum. If you are confident these costs are justified, then we request that you provide an explanation and additional documentation for review to justify such costs.

BACT – NOx from BFB

We request that you submit additional information to support the NOx BACT conclusion. Specifically, you should submit manufacturers data and/or engineering estimates of the uncontrolled NOx emissions and the expected performance of the SNCR and SCR (if technically feasible).

We note that the Deseret PSD Permit issued by EPA for a CFB boiler equipped with SNCR has a BACT limit of 0.08 lb/mmBtu on a 30-day rolling average. In addition, the Big Cajun Power Plant has permitted a CFB boiler with a NOx limit of 0.07 lb/mmBtu on a 30-day rolling average. We request that you provide additional documentation as to why these emission rates are not achievable for the BFB boiler that you are proposing.

[14] Pg. 5 and 6 of the April 18, 2008 application supplement.

BACT – Mercury from BFB

The application, at Pg. 6-35, concludes that activated carbon injection for mercury control is too expensive and references a "BACT economic threshold of $10,000/ton." Since the proposed usage of fossil fuel is small, the potential mercury emissions are small (relative to a facility that would burn only coal). However, the economic threshold of $10,000/ton, which may be appropriate for some NSR regulated pollutants[15], is not appropriate for mercury. If you continue to believe that fossil fuels are required to operate the BFB, you should compare the cost of mercury control to other situations where activated carbon injection for mercury control was accepted and/or rejected primarily based on cost. In addition, under the 112(g) case-by-case MACT review, you will need to identify what the best controlled similar source is for mercury emissions.

We also noted that the proposed emission limit for biomass only is very close to the proposed emission limit for biomass + 15% coal (biomass rate is 98% of coal rate, see Table 6-4). We request that you provide calculations and discussion to explain this. This should include the expected mercury concentration in the biomass, coal, Pet Coke, and TDF.

Applicability of 40 CFR 60, Subpart Da

The proposed BFB would be classified as a fossil fuel-fired electric utility steam generating unit (EGU). As such, it would be subject to the New Source Performance Standard (NSPS) at 40 CFR 60 Subpart Da[16]. This rule includes a number of requirements that do not appear to be adequately addressed in the application.

1. SO2 – Subpart Da includes an emission limit of 1.4 lb/MWh. The application does not include any calculations to show that this emission limit will be met if you were operating at your proposed emission limit of 0.10 lb/mmBtu. We request that you submit those calculations.
2. NOx – Subpart Da includes an emission limit of 1.0 lb/MWh. The application does not include any calculations to show that this emission limit would be met if you were operating at your proposed emission limit of 0.10 lb/mmBtu. We request that you submit those calculations.
3. PM – Subpart Da includes an emission limit of 0.015 lb/mmBtu. As an alternative to this limit, the rule provides a limit of 0.03 lb/mmBtu AND demonstration of 99.9% reduction. We note that the application does not mention the 0.015 lb/mmBtu limit. We are unsure if that was an oversight or if you intended to comply with the alternative limit. Related to this, we request the following information:
    a. Do you intend to comply with the NSPS PM limit by complying with the regular limit of 0.015 lb/mmBtu or the alternative limit?
    b. If you intend to comply with the alternative limit, we request that you provide a description of how you will comply with the percent reduction requirement, including calculations.
    c. We request that you provide an explanation of how your proposed BACT limit of 0.033 lb/mmBtu would be more stringent that the NSPS limit, as is required by BACT. We

[15] EPD notes that the BACT analysis is done on a case-by-case basis taking many factors, including cost, into consideration. There is no bright line cost threshold, otherwise this would circumvent the case-by-case nature of the review as required by the regulation.
[16] This federal regulation is adopted by reference in the Georgia Rules at 391-3-1-.02(8)(b)3.

understand that the issue of condensable vs. filterable particulate matter may be part of that explanation.

4. CEMS – In addition to requiring CEMS for NOx and SO2, which are very commonly installed and/or required on large fossil fuel-fired boilers, the NSPS also requires CEMS for Particulate Matter[17] and Mercury.[18] Contrary to how common NOx and SO2 CEMS are, CEMS for Particulate Matter and Mercury are very new. The application does not mention anything about CEMS for Particulate Matter or for Mercury, so it is unclear if you have considered these requirements.
5. Subpart Da Conclusion - We believe you would avoid being subject to NSPS Subpart Da altogether if you committed to burning only non-fossil fuels in the boiler. EPD would most likely not require the facility to install CEMS for Particulate Matter or Mercury if it burned no fossil fuels. As described in more detail in this letter in the section on "BACT – Clean Fuels for BFB," we believe this may be a viable option for the BFB and may possibly end up being a requirement of BACT.

Applicability of Acid Rain Regulations; 40 CFR Parts 72, 75, and 76

The Acid Rain Regulations impose limitations on the amount of SO2 and NOx that coal-fired power plants may emit. In addition, they require extensive continuous monitoring for SO2, NOx, CO2, heat input, and visible emissions. Similar to the conclusion reached above regarding applicability to NSPS Subpart Da, we believe you would avoid being subject to the Acid Rain Regulations altogether if you committed to burning only non-fossil fuels in the boiler. We note that you have not submitted the application for the Acid Rain permit yet.

BACT – Clean Fuels for Auxiliary Boiler and Stationary Engines

One BACT option that should be evaluated is restricting the use of fuels fired in the auxiliary boiler, emergency generator, and fire water pump(s) to biodiesel fuel, a cleaner burning fuel, rather than standard diesel fuel. During our meeting on June 4, 2008, you questioned the availability of biodiesel. Below is a list of biodiesel manufacturing facilities that have been permitted in Georgia. I am unsure as to their operational status or production levels, but these sources should help you locate a steady supply of the fuel. In addition, since you are located in southwest Georgia, near Alabama and Florida, you should look for suppliers of the fuel from those states as well.

AIRS #	Facility Name	County	Plant Description
5100229	Organic Fuels Holdings	Chatham	Biodiesel Manufacturing
6300121	Bulldog Biodiesel Production Facility	Clayton	Biodiesel Manufacturing Facility
8700054	Southwest Georgia Oil Company Inc	Decatur	This facility will manufacture biodiesel fuel.
11500108	US Biofuels Inc	Floyd	Biodiesel Mfg
13300020	Biodiesel Production Facility - Greensboro	Greene	Biodiesel manufacturing facility
21300036	Premier Polymers LLC	Murray	Biodiesel manufacturing facility
24500173	Farmers & Truckers Biodiesel LLC	Richmond	Biodiesel Manufacturing Plant
25700050	Georgia Mountain Biofuels, Inc.	Stephens	Biodiesel fuel manufacturing

[17] We note the NSPS does allow an alternative to PM CEMS, however, EPD is unlikely to allow that alternative.
[18] We note that the Mercury requirements of the NSPS, including the CEMS, were vacated by the decision in New Jersey v. EPA on February 8, 2008. However, through the state Mercury BACT requirement in 391-3-1-.02(2)(ttt), EPD would still most likely require a Mercury CEMS.

30300048	Advanced Biotechnologies Llc	Washington	Biodiesel Manufacturing Facility.
31900031	Alterra Bioenergy of Middle Georgia, LLC	Wilkinson	Biodiesel Manufacturing Plant

Applicability of 40 CFR 63, Subpart B

On February 8, 2008, the D.C. Circuit decided New Jersey v. EPA, vacating two EPA rules regarding emissions of mercury from electric utility steam generating units (EGUs). As a result of the D.C. Circuit's ruling, EGUs (coal or oil-fired) "remain listed" under §112(c) of the Act. Therefore, new coal or oil-fired EGUs that are major sources of HAPs are now be subject to the case-by-case MACT provisions of the Act in §112(g)[19] until the EPA promulgates a nationally applicable MACT standard to address hazardous air pollutants for this source category[20]. Pursuant to §112(g) requirements, Yellow Pine must apply for, and receive, a Permit that includes MACT emission standards for all of the hazardous air pollutants.

According to Application 17700, total HAPs emissions from the BFB are 231 tons per year. The MACT emission limitation or MACT requirements recommended by Yellow Pine and approved by the Division shall not be less stringent than the emission control which is achieved in practice by the best controlled similar source, as determined by EPD. EPD will consider an application that groups the many HAPs into categories provided all the regulatory requirements are satisfied. The principles of MACT determinations and the application requirements are found in 40 CFR 63.43(d) and (e). You should pay close attention to these requirements as you prepare your application.

If you have any questions or need more information, please contact me at (404) 363-7020 or via email at james.capp@dnr.state.ga.us.

Sincerely,

James Capp

James A. Capp
Program Manager
Stationary Source Permitting Program
JAC/tt

cc: George C. Howroyd, P.E. CH2M Hill

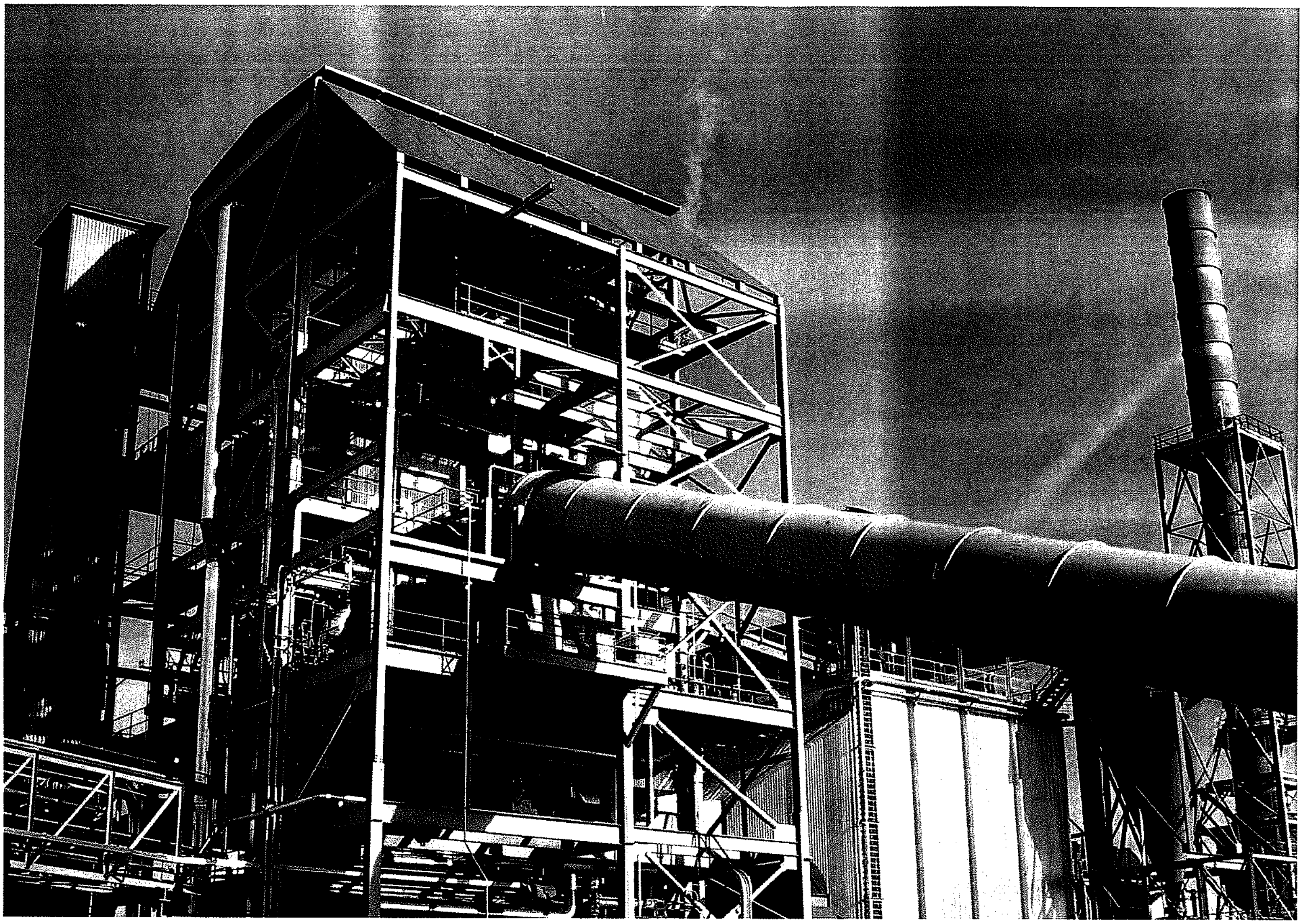
[19] Section 112(g) requirements are promulgated in 40 CFR 63, Subpart B. In Georgia, these requirements are found in Georgia Rule 391-3-1-.02(9)(b)16 and do differ somewhat from the federal rules.
[20] Memo from John Seitz dated August 1, 2001, "Case-By-Case MACT for New Oil- and Coal-fired Electric Utility Steam Generating Units"

Bubbling Fluidized-Bed Boilers

Burning Biomass and Low-Cost Fuels

Clean, efficient, reliable and easy to operate

B&W babcock & wilcox power generation group

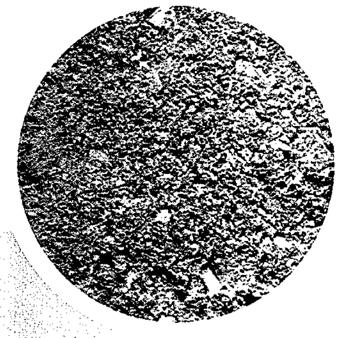


Since 1867, industries worldwide have benefited from The Babcock & Wilcox Company's engineering expertise, manufacturing technology and operating experience as a major supplier of steam generating equipment. Babcock & Wilcox Power Generation Group, Inc. (B&W PGG), a subsidiary of The Babcock & Wilcox Company, continues this tradition as a leader in reliable steam generation with our bubbling fluidized-bed (BFB) boiler.

B&W PGG's involvement with fluid-bed technology began in the 1950s with the first combustor at its state-of-the-art research center in Alliance, Ohio. Now, with an experience base of more than 30 BFB units, these facilities are helping the world realize the promise of clean energy from a wide variety of fuels.

Fuel Flexible

B&W PGG's bubbling fluidized-bed boilers can burn a wide range of low-cost opportunity fuels.



The ability to utilize various fuel sources and types provides owners with the flexibility to take advantage of changing cost and availability.

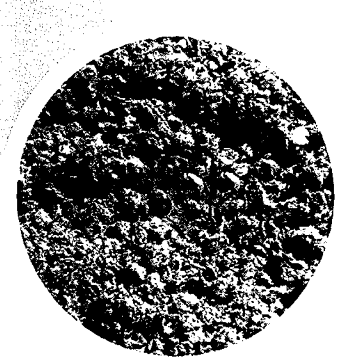
B&W PGG's BFB boiler is designed with a very large operating window to allow a wide range of fuels to be burned, separately or in combination.

This is necessary because fuel properties vary widely. For example, biomass fuels have a wide range of moisture and heating values depending upon their source and the time of year.

Our BFB boilers are designed with a high degree of flexibility to facilitate air movement between the bubbling bed and the overfire air system, to vary the gas recirculation volumes, and to adjust the fuel delivery to the bed. This operational flexibility allows owners to burn cheaper opportunity fuels and control fuel costs.

Viable fuels for a BFB:

- Wood waste
- Bark
- Paper mill sludge
- Recycled paper facility sludge
- Sewage sludge
- Tire-derived fuels (in combination)
- Oil
- Natural gas
- Coal (in combination)
- Peat
- Biomass
- Sugar cane waste
- Agricultural waste



Low Emissions

BFB boiler installations are proven to have lower NO_x, CO, VOC, SO_2 and particulate emissions than stoker-fired boilers with equivalent capacity.

Significant environmental benefits are achieved with BFB technology.

NO_x

Due to the low temperature sub-stoichiometric combustion processes that occur in the bubbling bed, the generation of nitrogen oxides (NO_x) is inherently lower than that of a stoker-fired boiler.

Because of good carbon burnout, a selective catalytic reduction (SCR) system can cost-effectively be located before dust removal equipment to further reduce NO_x.

CO and VOCs

Due to the intimate contact between the bed material and the fuel, improved fuel burnout occurs. This results in very low carbon monoxide (CO) and volatile organic compound (VOC) emissions.

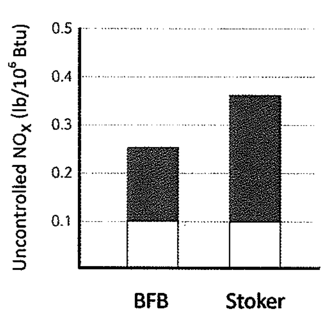
SO_2

The intimate contact between the fuel and bed material allows for in-bed capture of sulfur dioxide (SO_2). When burning biomass in combination with sulfur fuels, alkali normally present in the biomass will result in reduced SO_2. Limestone can also be added to the bed material for greater SO_2 capture.

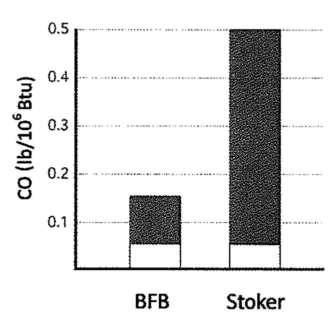
Particulate

Due to improved carbon burnout compared with a stoker boiler, the potential for fires in back-end environmental equipment is significantly reduced. This allows for the use of a baghouse to meet lower particulate requirements.

NO_X Comparison



CO Comparison



Reliable

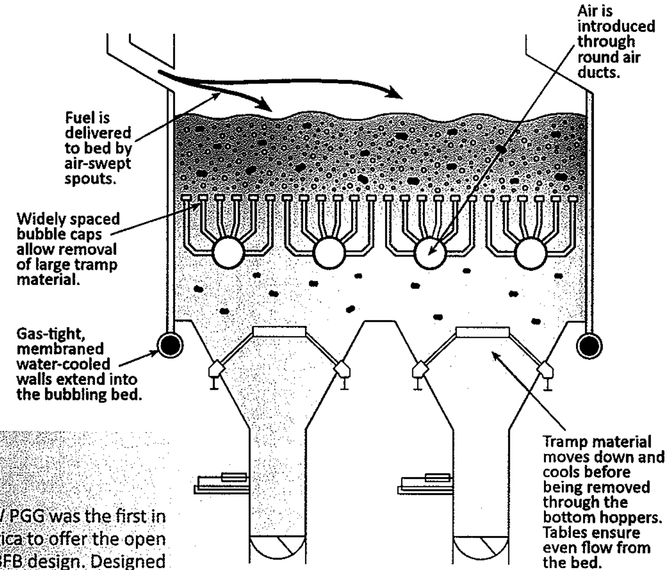
B&W PGG's advantage

B&W PGG's BFB boiler is designed with reliability in mind. Several features combine to provide low maintenance costs, high availability and long-term reliability:

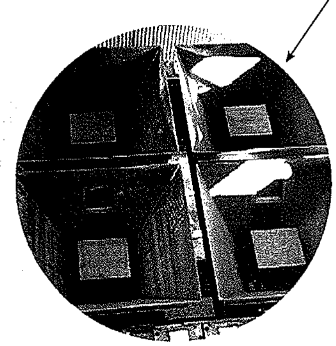
- An open bottom design permits easy removal of oversized or foreign material.
- A water-cooled, gas-tight lower furnace eliminates the potential for gas leaks caused from refractory damage.
- Bottom-supported hoppers remove load from the boiler, reduce capital requirements, and reduce potential mechanical stresses between water-cooled and non-cooled components.

Incorporated in B&W PGG's design are these features to reduce maintenance costs:

- No wear parts
- No moving parts
- No water-cooled screws or beams
- No cinder re-injection system
- Long-lasting bubble caps

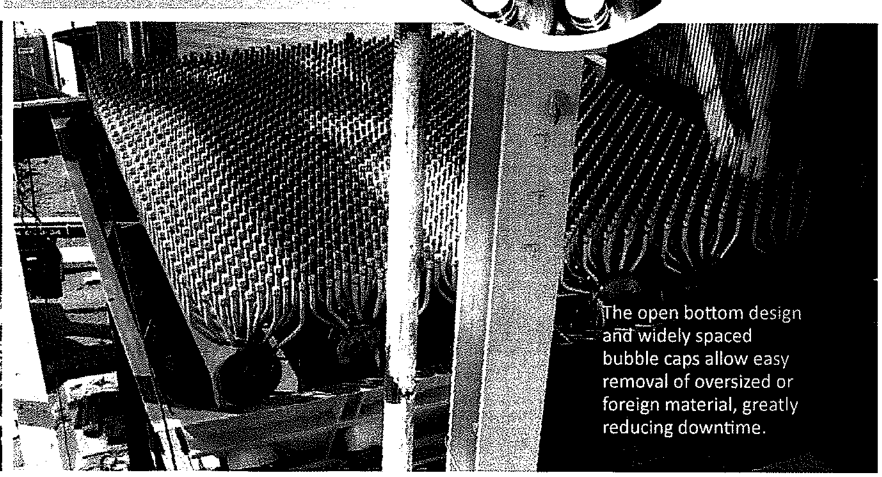


B&W PGG was the first in North America to offer the open bottom BFB design. Designed with no floor, the open bottom furnace results in complete debris removal with lower capital costs and maintenance expenses.



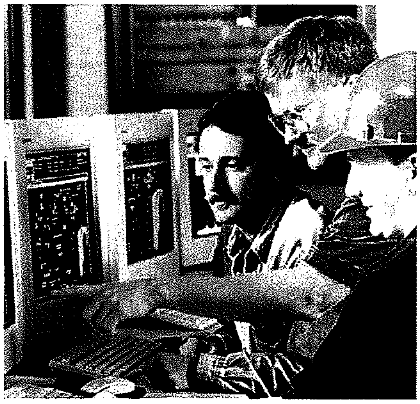
B&W PGG's underbed ash removal system consists of bottom-supported hoppers which isolate the bubbling bed foundation and steel from the boiler steel. This design is considered an advantage, particularly when retrofitting an existing top-supported unit to a BFB.

B&W PGG's bubble cap is durable and rarely requires replacement. In one installation, the original bubble caps are still in service 12 years after commissioning.



The open bottom design and widely spaced bubble caps allow easy removal of oversized or foreign material, greatly reducing downtime.

Easy to Operate



Advanced combustion controls automatically adjust to changes in operating conditions.

A B&W PGG BFB boiler responds rapidly to sudden changes in fuel and steam demand. This feature is a critical requirement for easy operation of the steam generator.

Our advanced controls system automatically moves air from the bed to the overfire air system and modulates the volume of gas recirculation to adjust for changes in the fuel or sudden changes in steam demand.

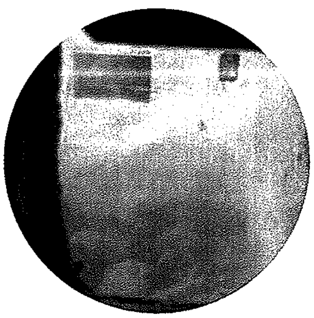
The bubbling fluidized bed carries an inventory of hot bed material that will rapidly convert the fuel's energy to steam. Automatically removing combustion air and fuel from the bubbling bed will accommodate rapid reductions in steam load.

The ability to adjust the throw distance of the fuel feed system allows fine tuning to accommodate variations in fuel moisture.

The B&W PGG bubbling fluidized-bed boiler is the ideal biomass combustion system.

Efficient

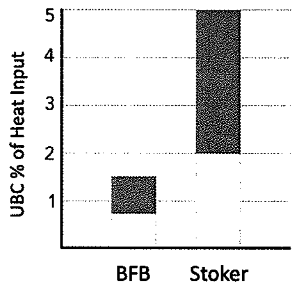
B&W PGG's BFB boilers provide improved efficiency. Intimate contact between the bed materials in the fluidized bed and the fuel reduces the carbon remaining from incomplete combustion and greatly reduces the excess air required. This improved efficiency means lower fuel costs.



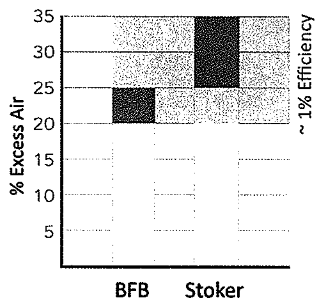
The thermal mass of the bubbling bed provides stability for fuel variations.

Lower fuel costs from better efficiency

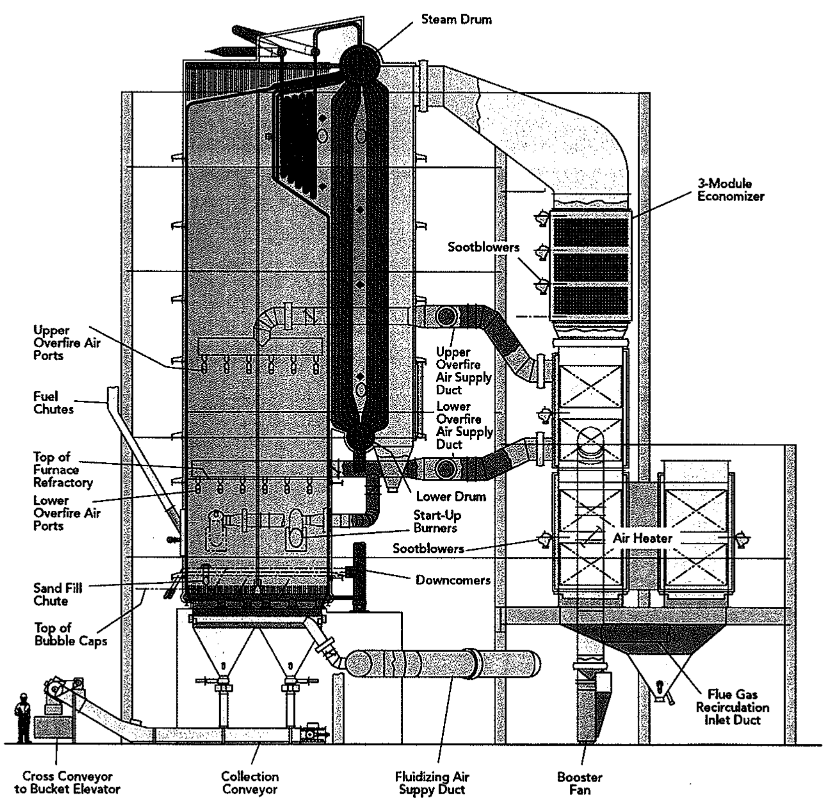
Efficiency improvement from improved carbon burnout



Efficiency improvement from lower O_2



Bottom-Supported Towerpak® BFB Boiler



BFB boiler specifications for a variety of applications

Design features:

- Top- or bottom-supported
- One- or two-drum designs
- New or retrofit boiler applications
- Provides an option to reduce SO_2 and NO_x emissions
- Reduces paper mill sludge volume while producing steam
- Superior to other technologies for burning wet wood-based fuels – between approximately 2800 and 3500 Btu/lb HHV (6513 and 8141 kJ/kg) without support fuels

Capacity:

- Bottom-supported: up to 225,000 lb/h (28.4 kg/s)
- Top-supported: from 225,000 to 1,000,000 lb/h (28.4 to 126 kg/s)

Steam pressure:

To 2600 psig (17.9 MPa) throttle pressure

Superheater/reheater outlet temperatures:

As required, up to 1000F (538C)

Fuels:

Able to burn a wide range of conventional fuels and waste fuels with high moisture, including:

- Wood wastes and bark
- Paper mill sludges
- Recycled paper facility sludges
- Sewage sludge
- Tire-derived fuel, in combination
- Oil and natural gas
- Coal, in combination
- Peat
- Biomass
- Sugar cane waste
- Agricultural waste

Whether you're considering a new BFB boiler, or a conversion of your recovery, stoker-fired power or small utility boiler, fluidized-bed combustion offers significant operational advantages:

- Fuel flexibility
- High efficiency
- Low environmental emissions
- Reduced capital costs and operating expenses

Why B&W PGG's fluidized-bed technology?

- The completely open bottom design has proven advantages
- Extensive research and development of fluid-bed combustion
- Operating experience with a wide range of unit sizes and high-moisture fuels

B&W offers quality and commitment to service

- Innovative design and technical expertise to increase production, optimize equipment and lower costs
- Capability, experience and track record to ensure your project will progress on schedule and reach performance targets
- A tradition of excellence since 1867

A comparison between BFB and stoker-fired technologies

	BFB	Stoker
Uses a baghouse and will meet particulate requirements	✔	
No furnace size limit	✔	
Lower NO_x emissions	✔	
Lower CO emissions	✔	
In-bed SO_2 control	✔	
Higher efficiency from lower O_2	✔	
Higher efficiency from low unburned carbon	✔	
Low potential for back-end fires caused by carryover	✔	
Stable steam generation with fuel variations	✔	
No moving parts	✔	
Burns high-moisture fuels and sludge	✔	
No cyclone dust collectors required	✔	
Small or no tubular air heater is ideal for recovery boiler retrofits	✔	
No submerged scraper conveyor	✔	
No high-maintenance cinder re-injection system	✔	
Can burn biomass and multiple fuels	✔	✔
Ability to remove oversized or foreign material in ash	✔	✔
No bed make-up material required	✔*	✔
Capital cost	✔	✔
Operating cost	✔	✔
High availability	✔	✔
High percentage coal		✔
High alkali fuels		✔
Refuse derived fuels		✔

*Not required on most BFBs

delivering
proven results

Babcock & Wilcox Power Generation Group, Inc. is a subsidiary of The Babcock & Wilcox Company (B&W). Established in 1867, B&W is a world leader in providing steam generating and emissions control equipment, nuclear operations and components, and defense program management services.

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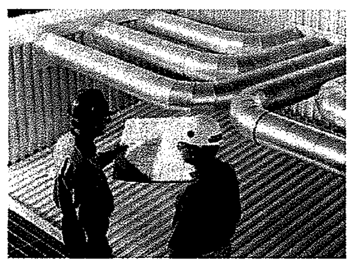

From engineering and design through construction and startup, B&W provides total support for your BFB project.

B&W power generation group

Babcock & Wilcox Power Generation Group, Inc.
20 S. Van Buren Avenue
Barberton, Ohio 44203 USA
Phone: 330.753.4511
Fax: 330.860.1886

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