SUMMIT ENERGY PARTNERS, LLC
SEP

December 3, 2008

James A. Capp
Program Manager
Stationary Source Permitting Program
Georgia Department of Natural Resources
Environmental Protection Division
4244 International Parkway, Suite 120
Atlanta, GA 30354-3906
VIA OVERNIGHT MAIL

Re: PSD Application No. 17700 dated September 27, 2007
Yellow Pine Energy Company, LLC (Yellow Pine)
Fort Gaines, Georgia (Clay County)
AIRS No. 06100001

Dear Jac,

Further to my meeting with Jim Ussery and Chuck Mueller on October 31, 2008, where we discussed a letter listing the remaining information requirements for the above referenced permit application and your letter of November 12, 2008, below please find the below reply; your statements are listed, followed by our reply in blue.

1. Supplemental Fuels - Coal and Pet. Coke

It is our understanding that you have withdrawn your request to burn bituminous coal and/or petroleum coke (Pet. Coke) at the facility. Therefore, those fuels are no longer under consideration in our review of the application.

The withdrawal of bituminous coal and petroleum coke was always contingent upon retaining TDF as Yellow Pine requires a supplementary fuel for safety and reliability as stated in several of our prior submissions.

There is simply no operating experience with a BFB (Bubbling Fluidized Bed) the size of Yellow Pine anywhere in the world from which one could reasonably conclude that a supplemental fuel is not needed (see TDF section below).

2. Supplemental Fuels - Tire Derived Fuel (TDF)

In our June 17, 2008 letter, we asked for TDF specifications from one of your likely TDF suppliers. In your response, you were unable to provide the specifications because the type of TDF you would need was not currently available[1]. Specifically, you stated, "Although Yellow Pine hopes vendors will modify their product to supply 95% metal-free TDF variety, no assurances can be given that this refined type of TDF will be commercially available on economic terms and in volumes needed by Yellow Pine in the future." Based on this response, as well as the lack of demonstrated need for supplemental fuels in general, EPD does believe it is appropriate to move forward with proposed BACT and MACT emission limits when burning TDF. We are considering authorizing a trial burn of TDF in the permit that would allow us to see the impact on emissions and for you to see if the TDF would be advantageous from an operational standpoint.

Obviously, Yellow Pine has since stated in our August 20, 2008 meeting with you, Jim Ussery and Chuck Mueller that Yellow Pine is willing to accept the risk of securing TDF faced with EPD's request to delete coal and petroleum coke supplemental fuels or EPD would stop work on Yellow Pine's application.

We understood from our August 20, 2008 meeting and discussions thereafter, that the proposed limited use (5% by weight) of TDF was acceptable, and the follow-up information requested (sent all parties via e-mail on October 3, 2008) was the TDF chemical composition data from the publication: US EPA's Clean Air Technology Center, "*Air Emissions From Scrap Tire Combustion*" We also provided an analysis of three units referenced in that report on PM, SOx, NOx and CO which use biomass/TDF blends.

Further in the August 20th meeting in response to your comment regarding boiler vendor marketing claims as the basis for your position on not need a supplemental fuel, we presented the case of JEA's Northside CFB, which at the time was the largest CFB ever to be built. Contrary to the boiler vendor's marketing claim, that unit suffered years of poor performance. Marketing claims are not solid evidence.

The gasification of a solid fuels while suspended in air in a large cross-section vessel cannot be underestimated for its stability challenges. Neither BACT nor MACT by law are to be used to compromise the reliability or safety of the plant's operation. Therefore, the criteria EPD ought to be applying is a lack of demonstrated proof a BFB unit the size of Yellow Pine has in fact operated successfully without a supplemental fuel. EPD should not second-guess how Yellow Pine's unit will operate and that a supplemental fuel will never be needed. Therefore, permit limits incorporating limited 5% TDF use (by weight) ought to be forthcoming.

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[1] We note that you did provide specifications from other TDF sources.

There is no purpose served by a "trial burn" when: (a) Georgia EPD has already permitted all of the State's pulp mills to use TDF, (b) as recently as January 2007 EPD permitted Pratt Industries/Visy Paper's fluidized bed project to use TDF in proportions much greater than that proposed by Yellow Pine (In fact that project was permitted to use "carpet fluff" without a "trial burn.") and (c) the EPA data reported air emissions for biomass and TDF mixtures since 1997. Technically, there is nothing more to diagnose. EPA's papers on TDF are clearly in favor of recovering waste tires and an environmentally sound policy.

Based on the TDF specification stated in our August 1, 2008 correspondence (which are consistent with the EPA data), the biomass/TDF NOx limit is calculated to be 0.11 lb/mmbtu for a BFB with SNCR. The biomass/TDF limit for SOx is readily addressed by a function of the sulfur content of the biomass/TDF mix and the control methodology stated in your November 12, 2008 letter, just as EPD did in the Longleaf permit for various coal sulfur contents.

We don't' understand why you have regressed from moving forward on the small use of TDF for supplemental fuel in light of the following: (a) it was yourself who recommended the use of TDF to us, that we then undertook and succeeded in amending the Clay County special use authorization to allow the use of TDF, (b) this fuel will at most be five percent (5%) by weight of the plant's fuel input, and because it is more costly than biomass is used sparingly, (c) TDF is not a fossil fuel and use of 5% by weight satisfies the safety and reliability criteria of utility Good Industry Practice, (d) waste tires will otherwise continue to go to landfills to the detriment of the environment, when they could be recovered and used to provide energy per the Nation's energy self-sufficiency goal and (e) sixteen (16) months into this permit process, a trial burn is suggested, rather than suitable limits as we have proposed using your BACT calculation method in your November 12, 2008 letter.

3. NOx BACT

We have recently spoken with representatives from some of the leading biomass boiler manufacturers in the United States[2]. Based on those conversations, and your application, we believe that the manufacturers are very unlikely to guarantee a NOx emission rate of less than 0.10 lb/mmBtu for biomass combustion in a Bubbling Fluidized Bed (BFB) boiler using Selective Non-Catalytic Reduction (SNCR) for NOx reduction. Therefore, unless and until we obtain additional information leading to a different conclusion, we plan to use 0.10 lb/mmBtu as the NOx rate in the BACT analysis for SNCR.

As stated in several of our prior submissions, NOx limits of 0.10 lb/mmbtu on 100% biomass and 0.11 lb/mmbtu on biomass/TDF, each on a 30-day average, are suitable limits for a BFB with SNCR and is BACT.

[2] Kerry Flick with Metso Power, John DeFusco with Babcock & Wilcox, and Rich Abrams with Babcock Power

EPD asked you on a couple of occasions[3] to look into the technical feasibility and cost effectiveness of Selective Catalytic Reduction (SCR) for NOx reduction. In your original application, you stated, "SCR is considered technically infeasible and will not be considered further in this application.[4]" Then in the April 16, 2008 letter, you stated, with respect to a 'back-end' SCR system that the "cost effectiveness of the 'back-end' SCR system would be approximately $63,400 [per ton]." You also stated that the system would require a 224.9 mmBtu/hr reheat system[5]. Finally, in your August 1, 2008 letter you stated, "No additional scenarios are technically feasible, and therefore, no additional calculations were performed."

We believe that your reported cost effectiveness for a 'back-end' system is too high and we believe that there is an additional scenario that should be considered. Specifically, we request that you obtain a quote from Babcock Power Environmental for their Regenerative Selective Catalytic Reduction (RSCR) system. The quote should include the option for addition of an oxidation catalyst for CO control. You can contact Mr. Rich Abrams, Vice President of Renewable Energy for Babcock Power Inc. at 508-854-1140 (e-mail is rabrams@babcockpower.com).

Babcock Power does not manufacture a BFB, only a stoker boiler. It developed "back-end" RSCR pollution controls in order to allow its stoker boiler to meet modern emission limits in non-attainment areas, particularly for the New England stoker retro-fit market, which has high electricity rates and mandatory renewable energy credit revenues. In the case of a new plant, if one is going to require the addition of a $28 million RSCR system, then one might as well build a lower cost stoker boiler to compensate. The RSCR system is cost is prohibitive for a state-of-the-art BFB boiler.

As requested, we contacted Babcock Power, received their quote and had our engineering firm, Merrimac Associates, Inc., prepare another BACT analysis for a RSCR system (see Exhibit A). Merrimack Associates recently completed commissioning on a tail-end SCR system for the Mercer Station in New Jersey. We raise this point because in our telephone conversation with you on October 30, 2008, you stated a figure that Babcock Power's sales representative had claimed its system cost about $5,000/ton of NOx removal, which seemed too good to be true based on the earlier April 16, 2008 BACT analysis. Also, the Babcock Power scope left out many costs, which are required to install and operate the units, nor did it fully substantiate the energy consumption using engineering formula modeled on the system's alternating regenerative cycle. Merrimac's experience on the Mercer Station provided an objective view versus a marketing claim.

Merrimac's analysis shows that the RSCR system is cost prohibitive ($17,100/ton NOx removed, before costs of additional emission allowances and potential CO2 taxes on

[3] February 15, 2008 letter, item #8 and June 17, 2008 letter, page 7
[4] Page 6-13
[5] Page 7 and Attachment B in letter dated April 16, 2008

fossil fuels). The RSCR system has very substantial fossil fuel use and additional SOx, VOC, PM and HAP emissions from burning the fossil fuel which are uncontrolled.

We emphasize that given the Nation's goal of energy self sufficiency, and potential CO2 taxes on fossil fuels, it would appear unwise to have a new biomass-fired plant, using state-of-the-art fluidized bed technology, be tasked with consuming 30,000,000 gallons of fuel oil over its life, largely from foreign oil sources, in order to reduce NOx in a rural attainment area from 0.10 to 0.07 (lb/mmbtu).

4. CO BACT (And Surrogate for Organic HAPs)

Similar to the discussion above regarding NOx, based on our recent conversations with boiler manufacturers, and your application, we believe that the manufacturers are very unlikely to guarantee a CO emission rate of less than 0.149 lb/mmBtu for biomass combustion in a Bubbling Fluidized Bed (BFB) using good combustion practices. Therefore, unless and until we obtain additional information leading to a different conclusion, we plan to use 0.149 lb/mmBtu as the CO rate in the BACT analysis for good combustion practices. To allow for variability, this rate would be based on a 30-day average. If the RSCR technology described above for reducing NOx is determined to be BACT for NOx, it is possible that the addition of the oxidation catalyst will be technically feasible and cost effective. That is why we requested you obtain the RSCR quote with the option for addition of an oxidation catalyst for CO control.

As stated in our prior submissions, a CO limit of 0.149 lb/mmbtu on a 30-day average for a BFB using good combustion practice is suitable and is BACT and MACT.

The BACT analysis for NOx using a RSCR system was found to be cost prohibitive with negative corollary impacts. In addition to the cost issue, as documented in prior submissions, CO catalysts are poisoned by elements in biomass flue gas, even in a "tail-end" system. The CO catalyst vendor we contacted (see August 1, 2008 documentation) stated so and refused to warrant performance, and therefore, is not technically feasible.

5. PM10 BACT (PM10 as Surrogate for PM2.5 BACT and PM10 as Surrogate for non-mercury metal HAPs)

Longleaf Energy coal plant proposed in Early County has proposed a PM10 emission rate of 0.010 lb/mmBtu (filterable) as MACT in their recent 112(g) application. Your original application says that similar projects have been permitted as low as 0.010 lb/mmBtu[6]. During our meeting with Babcock Power, their representative stated that rate was definitely achievable for a biomass boiler equipped with a dry scrubber and baghouse. Therefore, unless and until we obtain additional information leading to a different conclusion, we plan to use 0.010 lb/mmBtu filterable and 0.018 lb/mmBtu total as the BACT rates for PM10. These rates would be based on the stack test methods listed in the permit.

[6] Page 6-19

US EPA published a final rule for "Implementation of the New Source Review (NSR) Program for Particulate Matter Less than 2.5 Micrometers (PM2.5)." in the Federal Register on May 16, 2008. For States with SIP approved programs, such as Georgia, the final rule allows a transition period to allow the States time to amend their own rules. In the meantime, these States are allowed to continue the practice of using PM10 as a surrogate for PM2.5[7]. Since we have not had time to our amend our rules to incorporate the requirements for PM2.5, we are using PM10 as a surrogate for PM2.5 for your application.

Babcock Power does not manufacture bag houses as they rely on other vendors for particulate control devices. We therefore went the next step and contacted Dustex Corporation of Kennesaw, Georgia, who is a manufacture of utility-scale bag houses.

Based on Dustex's information, a PM limit of 0.010 lb/mmbtu (filterable) on a 30-day average is suitable and is BACT and MACT.

Dustex did not support your proposed condensable fraction of 0.008 lb/mmbtu. We note that in the Nacadoches, Texas BFB biomass project, the total PM limit is 0.030 lb/mmbtu, which implies 0.015 lb/mmbtu of condensables. Plant Carl, a small biomass and chicken litter plant's PM limit approved by EPD in May 2008 is 0.026 lb/mmbtu. We have not found any testing evidence or NACAA data or EPD data to support 0.008 lb/mmbtu of condensables from biomass flue gas. Biomass flue gas has a high moisture content, which may impact condensables.

Our concern is that if 0.008 lb/mmbtu is an arbitrary figure and is too low, then equipment vendors will balk at guaranteeing the limit, which would make the Project unviable. Therefore, unless Georgia EPD has solid evidence of what the biomass flue gas condensable fraction is and a suitable statistic confidence interval on which to base a limit, it is unwise to set a condensable fraction limit so low. Instead, we suggest using the Nacaodoches condensable PM (0.015 lb/mmbtu), subject to re-determination upon stack testing and statistical variance analysis of the test results.

6. SO2 BACT

Your claim that uncontrolled biomass SO2 emissions are 0.92 lb/mmBtu[8], and your proposal that BACT for burning 100% biomass should be 0.06 lb/mmBtu, are simply not credible based on available information. Your original application listed the sulfur content of biomass as 0.02% sulfur[9]. We believe this figure to be somewhat high, but not

[7] 73 FR 28340

[8] We note that the application contains contradictory information regarding the uncontrolled SO2 emission rate. For example, on page 6 of the August 1, 2008 submittal it shows 0.92 lb/mmBtu three times and 0.092 lb/mmBtu two times.

[9] Page 4-1

completely unreasonable. We believe a more realistic figure, based on your own data supplied with the application[10] and based on EPA AP-42 emission factors for wood combustion[11], is 0.01% sulfur.

We specifically raised this issue to you in our June 17, 2008 letter and you were specifically asked to revisit your SO2 calculations during our meeting of September 25, 2008. Your e-mail to me on September 26, 2008 acknowledged this. You never did.

Assuming an average sulfur content of biomass of 0.01% sulfur, 30% control of SO2 in the boiler (as stated in your application), and 70% control of SO2 in the scrubber (EPD has lowered this from your estimate of 91% control based on the lower uncontrolled SO2 emission rate), results in a proposed BACT emission rate of 0.010 lb/mmBtu for SO2. Therefore, unless and until we obtain additional information leading to a different conclusion, we plan to use 0.010 lb/mmBtu as the BACT rate for SO2. To allow for variability, this limit would be based on a 30-day average. Calculations are attached.

For many months, we have been asking EPD where did it come up with its biomass sulfur content and this is still unanswered. Our own research has found no data to support the 0.01% sulfur content assumption. Recall we agreed with you in our September 25, 2008 meeting to each check the biomass sulfur specification on page 6 of the August 1, 2008 letter. If one did so, one would conclude that the figure is 0.20% (maximum) sulfur, which corresponds to the calculation tables on page 6. We reconfirmed this in our emission limit table sent via e-mail on October 24, 2008. In several submissions, we referenced biomass sulfur content data from very credible sources and other permits as discussed below.

One such reference is the research paper by the National Council of the Paper Industry for Air and Stream Improvement, Technical Bulletin No. 96, *Information on the Sulfur Content of Bark and its Contribution to SO2 Emissions When Burned as Fuel,* where it tested wood and bark wastes at pulp mills in the U.S. Southeast (Georgia, Alabama and Florida) an found the sulfur content to range from 0.06% to 0.134%.

Prior to your letter of November 12, 2008, we provided you a copy of this reference paper. Further, this report states on page 7:

> "The properties of wood residues and bark fuels can vary so greatly that a standard specification is not possible. The differences should be recognized and accounted for in the engineering and operation of wood-fueled systems."

Further, we supplied you the chemical analysis of hardwood and softwood species, which show sulfur content of 0.10%, a factor ten (10) times greater than the sulfur content you

[10] Wood Sulfur Information Attachment to November 30, 2007 Yellow Pine Response Letter to October 19, 2007 EPD Comments

[11] Table 1.6-2 of AP-42 shows an uncontrolled emission rate of 0.025 lb/mmBtu.

are stating above. We also supplied you data of 0.16% sulfur for Switchgrass, which may be used for fuel in the future.

We also supplied you with an assessment of the NACAA wood-fired units, which showed an average actual SOx emission rate of 0.249 lb/mmbtu, a variance of 0.328 lb/mmbtu, implying a statistical upper end of the range of 0.970 lb/mmbtu. None of the foregoing test results are plausible if biomass has a sulfur content of 0.01%. Even if one assumes the NACCA results are totally uncontrolled, then the average sulfur content in biomass would be 0.054% and the upper end of the range would be 0.21% sulfur.

We have looked at the controlled limits for other biomass projects and suggested these to you. The Nacadoches, TX biomass project has a SOx limit of 0.046 lb/mmbtu (30-day average). The Babcock & Wilcox Wauna biomass plant tested at 0.04 lb SOx/mmbtu against a permit limit of 0.06 lb SOx/mmbtu and a control efficiency of 80%, which implies a fuel sulfur content of 0.06% (30 day average). In the May 2008 Plant Carl permit, although the sulfur fuel content is not limited, the uncontrolled emission translates to 0.07% sulfur on an equivalent HHV BTU/lb basis.

The conclusions of the above documentation are simply this: (a) biomass is not a homogenous fuel and does not come with a sulfur specification like coal; (b) the sulfur content can and will vary over species, bark versus core and over time as the biomass sources expand into plants such as Switchgrass; (c) several sources reported biomass sulfur content ranging from 0.06% to 0.21%; and (d) one should account for high variability by allowing a margin in the permit limits.

We agree with the formula provided in your exhibit to your November 12, 2008 letter to translate sulfur content in the fuel to an emission limit. But because your assumed sulfur content differs from our specification by a factor of 10 to 20 times, the controlled limit you state (0.010 lb SOx/mmbtu) cannot be justified or attained.

We are respectfully submitting it is not feasible to meet the proposed 0.010 lb /mmbtu SOx limit; no one has and no one could because the sulfur content (0.01%) you are using is not supported. Our own research over many months did not validate your suggested sulfur content. All of the above references support Yellow Pine's specification of a maximum sulfur content of 0.20% and an average of 0.06% sulfur.

Given the wide variability of the sulfur content in biomass, and the limited use of TDF, Yellow Pine proposed in its October 24, 2008 table to tier the SOx emissions as a function of the fuel sulfur content. This is the same approach as used in the Longleaf permit for different coal sulfur contents. This table for SOx and the related calculations are attached in Exhibit B hereto.

7. Acid Gas HAPs (Hydrogen Chloride as Surrogate)

Emissions of Hydrogen Chloride (HCl) from biomass combustion are related to the amount of chlorine in the biomass. Even though you included HCl in your 112(g) analysis in Appendix B of your August 1, 2008 submission, we can not figure out how you derived an uncontrolled HCl emission rate of 0.19 lb/mmBtu and a controlled HCl emission rate of 0.019 lb/mmBtu. We do note that the uncontrolled HCl emission rate in EPA's AP-42 document is 0.019 lb/mmBtu[12]. Based on that data alone, a controlled emission rate of 0.019 lb/mmBtu seems unreasonable. In the absence of any more specific data related to the chlorine content of the biomass, we see no other alternative than to look towards the National Association of Clean Air Agencies (NACAA) document released June 2008 titled, "Reducing Hazardous Air Pollutants from Industrial Boilers: Model Permit Guidance." This document provides guidance on achievable HAP emission rates for existing boilers and offers a recommended range of emission rates from 0.006 lb/mmBtu to 0.012 lb/mmBtu. Because your boiler would be new and equipped with state of the art pollution controls (dry scrubber for SO2 and HCl control), we believe the low end of NACAA's recommended range is appropriate. Therefore, unless and until we obtain additional information leading to a different conclusion, we plan to use 0.006 lb/mmBtu as the MACT rate for HCl (as a surrogate for Acid Gas HAPs).

In May 2008, EPD issued the permit for Plant Carl, a small biomass and chicken litter fired plant. In that MACT analysis EPD found that the *uncontrolled* HCl level is 0.196 lb/mmbtu and the controlled MACT finding was 0.017 lb/mmbtu. Yellow Pine referenced these figures in its MACT analysis. If EPD used fuel chlorine content data to determine those levels, then the same would be applicable to Yellow Pine, excluding the chicken litter component.

It is instructive that the Nacadoches, TX HCl permit limit is 0.0213 lb/mmbtu (30 day average) and the Snowflake, AZ biomass plant's permit has a HCl limit of 0.06 lb/mmbtu. Both permit limits are greater than the uncontrolled AP-42 factor.

Further, we reported on the NACAA units greater than 500 mmbtu/hr, or about one third the size of Yellow Pine, and *none* of these units achieved the limit you have proposed (0.006 lb/mmbtu). The testing results ranged from 0.007 to 0.026 lb/mmbtu with an average of 0.019 lb/mmbtu and permit limits of 0.09 lb/mmbtu. If EPD is going to use the NACAA data as its reference, then EPD ought to recognize the unit size factor.

We understand Metso Power explained this size consideration to you and the liability implications of their emission guarantees. We also stated that Metso Power is not willing to guarantee 0.006 lb/mmbtu on a BFB unit this size. Not because it isn't a new unit, but because it hasn't been demonstrated on a unit even one-third of Yellow Pine's size.

[12] Table 1.6-3 of AP-42

Neither Yellow Pine nor any other utility can use a permit limit, which a manufacture cannot guarantee. That is why we facilitated the presentation by Metso Power and prepared a diagnosis of the NACAA data for you (which you said EPD did not have resources to look into). We had hoped that these presentations would lead you to realize that for a BFB unit the size of Yellow Pine, the low end of the NACAA range has not and cannot be met by a large BFB biomass unit, and it is essential to a viable project to have a permit limit a manufacture can guaranty. Even in the most stringent permits in Connecticut on much smaller units, the HCl limit is determined by fuel input, control efficiency and stack test. Control for acid gases (HCl) would follow your control methodology in November 12, 2008 exhibit.

We are now sixteen months into this permit process, and this process is not advanced by EPD suggesting a limit knowing it isn't viable for a unit Yellow Pine's size, knowing it is not in fact supported by the NACCA data for units even one-third the size of Yellow Pine and knowing it cannot be built and guaranteed by a manufacturer. MACT allows for these considerations, and we request the EPD revise its proposed HCl limit based on its MACT finding in June 2008 (Plant Carl) of 0.019 lb/mmbtu, with re-determination based on stack testing and statistical variance analysis of the test results.

Note that because of the humid nature of biomass flue gas, some manufactures are using spray dryer adsorbers with hydrated lime instead of dry scrubbers with crushed limestone and recycled ash. Yellow Pine requests the flexibility to use either system because the control efficiency is the same for acid gases (SOx, H2SO4, HCl).

<u>Summary</u>

When we met with Jim Ussery and Chuck Mueller on October 31, 2008, we raised our concern that the numerous letters (now 6) were going in circles and delaying the project beyond what is viable for Yellow Pine. We related the situation with Yellow Pine's electricity sales contracts, how Yellow Pine we had to forfeit a contract with Georgia Power because the 14-month air permit milestone could not be met. We related that the new replacement contracts have their time limits too, which are fast approaching. We are very concerned by your comment on October 30, 2008 that it didn't concern you that these new contracts would be lost if the delays continued. We tried to explain that the project's viability, given today's finance market, is dependent on these contracts with electric utilities.

Our partners are very concerned that even though the State of Georgia's stated goal and Governor's Order is to expedite renewable energy projects, there is no sense of urgency and yet another letter was sent. We have used thousands and thousands of man-hours to investigate various marketing claims by vendors, research papers and other permits. To the best of our abilities and based on credible, reasonable evidence, we have documented in the above responses, what is viable for the project.

The remaining issues are:

(a) to permit the use of TDF at 5% by weight and provide relevant NOx and SOx limits for the biomass/TDF mix;

(b) to eliminate "tail-end" RSCR system as BACT for NOx and MACT for CO and use the above noted limits based on SNCR and good combustion practice respectively;

(c) to increase the condensable PM fraction from 0.008 to 0.015 and allow for stack testing adjustment;

(d) to accept Yellow Pine's documentation of fuel sulfur content and the resultant emission limit tiers based on EPD's calculation methodology (see Exhibit B); and,

(e) to increase the HCl limit consistent with the MACT finding and manufacture's guarantee and allow stack testing adjustment.

We request a follow-up meeting to resolve these issues as soon a practical and the timely issuance of a draft permit.
Sincerely,

On behalf of Yellow Pine Energy Company, LLC

Mark S. Sajer
Managing Director

Encl.

Exhibit A

Yellow Pine Project - BACT Analysis
Regenerative "Tail End" SCR w/ Aux. Firing for Control of NOx

Input Data

Item	Value
Total Hours per year @ 90% CF	7,884
RSCR Economic Life, years - Vendor Quote	10
Catalyst Warranty - years - Vendor Quote	2
Discount Rate (%)	10.00
Flue Gas Flowrate (lb/hr) - Boiler Vendor	1,757,682
Flue Gas Temperature from Baghouse (F) - Boiler Vendor	286
Temperature (^oF after reheat) - Vendor Quote	470
Uncontrolled NOx, lb/mmbtu	0.22
Fuel Input (mmbtu/hr) - Permit Application	1,529
NOx From boiler (lb/hr)	336
NOx Emissions (tpy) from boiler	1,326.0
Controlled NOx emission (lb/mmbtu) - Vendor Quote	0.07
As tons/year	422
Site Specific Electricity Cost ($/kWh)	0.085
Site Specific Operating & Maint. Labor Cost ($/hr)	$62.00
Aqueous Ammonia Cost ($/gal) - Vendor Quote	$0.80
Ult.LowS Diesel Oil ($/gal, DOE EIA, 12 mo. Avg. delivered)	$4.50

Capital Costs

	Regenerative SCR	
	Value	Basis
Direct Costs		
1.) Purchased Equipment Cost		
a.) Equipment cost, exempt from sales tax	$15,500,000	Vendor Quote
b.) Acq. Ammonia Storage and Feed System	$350,000	Estimate
c.) Instrumentation	$0	Included
d.) Induced Draft Fan - Vendor Spec.	$475,000	21 inches water capacity
e.) Fuel Oil or Propane storage, pumps and meters	$375,000	Estimate
f.) Freight	$0	Included
Total Purchased equipment cost, (PEC)	$16,700,000	B
2.) Direct installation costs		
a.) Foundations and supports	$835,000	0.05 x B
b.) Handling and erection	$4,175,000	0.25 x B, Vendor Quote
c.) Electrical	$167,000	0.01 x B
d.) Piping	$167,000	0.01 x B
e.) Sales taxes	$58,450	7% on construction mat'ls
g.) Insulation for ductwork & painting	$167,000	0.01 x B
h.) Stack & ID fan modification	$334,000	0.02 x B
Total direct installation cost	$5,903,450	
3.) Site preparation	NA	As Required, SP
4.) Buildings	NA	As Required, Bldg.
Total Direct Cost, DC	$22,603,500	1.25B + SP + Bldg.
Indirect Costs		
5.) Engineering	$334,000	0.02 x B
6.) Construction and field expenses	$835,000	0.05 x B
7.) Contractor fees	$1,670,000	0.10 x B
8.) Start-up	$334,000	0.02 x B
9.) Performance test	$167,000	0.01 x B
10.) Contingencies	$2,505,000	0.15 x B
Total Indirect Cost, IC	$5,845,000	0.35 x B + Other
Total Capital Investment (TCI) = DC + IC	**$28,448,500**	**1.60B + SP + Bldg. + Other**

Annual Costs

Item	Value	Basis
1) Electricity		Engineering Calc.
ID Fan, burner fan & motors -power equirement (kW) - Vendor Quote	1,437	14" Dp @ 96kW/in + 91.2 KW
Electric Power Cost ($/kWh)	0.085	
Continency (15%)	144,414	
Cost ($/yr)	$1,107,175	
2) Operating Costs		Estimate
Operating Labor Requirement (hr/shift)	1	1 hour per shift
Unit Cost ($/hr)	$62.00	Facility Data
Labor Cost ($/yr)	$67,700	
3) Ammonia Costs ($/gal)	0.80	Vendor Quote
Hourly Requirement (gal/hour)	72	Vendor Quote - 36 gal/hr/train x 2 trains
Annual requirement (gal/year)	567,648	
Contingency (15%, gal/yr)	85,147	
Total Ammonia Costs ($/year)	$522,236	
4) Reheat		
Supplemental firing (calculation, MMBtu/hr)	92	Vendor Quote, flue gas from 286 to 470 F
Recovery by Heat Exchanger	94%	Vendor Quote
System Losses (5%/cycle + surface loss, mmbtu/hr)	4.65	Calculation, Vendor Quote 120 deg F
Net Reheat Fuel Consumption (mmbtu/hr)	10.2	net w/ Regen HX + system losses
Heating value of #2 Fuel Oil (Btu/gal)	140,000	
Low Sulfur Fuel Oil cost ($/gal incl. tax & delivery)	$4.80	Ult-Low Diesel, deliv. EIA 12.mo. Avg
Supplemental firing Cost	$2,748,759	
Contingency (15%)	$412,314	
Total Cost	$3,161,073	
Total Operating Costs	**$4,858,183**	
4) Supervisory Labor		
Cost ($/yr)	$10,160	15% Operating Labor
5) Maintenance		
Maintenance Labor Req. (hr/year)	164.3	1/2 hour per day
Catalyst Replacement Labor Req. (hr/yr)	880.0	8 men for 220 hours
Unit Cost ($/hr)	$62.00	Facility Data
Labor Cost ($/yr)	$64,740	
Material Cost ($/yr)	$64,740	100% of Maintenance Labor
Total Cost ($/yr)	$129,480	
6) Catalyst & Regeneration Cycle		
Initial Catalyst Cost, 1 tray / canister, 12 canisters ($)	$3,885,000	Catalyst @ $370/cf & 10,500 cf/MW
Sales Tax ($)	$0	0% Sales Tax
Catalyst Cycle (yrs)	2	2 yr warranty - Vendor quote
Interest Rate (%)	10.0	i

CRF	0.58	Amortization of Catalyst
Regneration Program Cost ($/yr)	$971,250	4 of 12 catalyst trays regenerated/year
Ammortized Cost + Regen Program Cost ($/yr)	$3,209,750	(Volume)(Unit Cost)(CRF)
7) Indirect Annual Costs		
Overhead	$124,400	60% of O&M Costs
Administration, purchasing & catalyst program mgmt.	$142,240	.0.5% of Total Capital Investment
Property Tax	$0	Exempt
Insurance	$327,160	1.15% of Total Capital Investment
Capital Recovery on Total Capital Investment	$4,629,860	CCR (10 yrs, 8.5% interest rate)
Total Indirect & Capital Recovery ($/yr)	$5,223,660	
Total Annualized Cost ($/yr)	**$13,431,200**	
Total Controlled (tpy)	**783.6**	
Cost Effectiveness ($/ton NOx removed)	**$17,100**	

Exhibit B

Yellow Pine Project

SOx Calculations and Proposed Tiers

Data Set

Boiler Capacity	1,529	mmbtu/hr – permit application
Biomass Energy Content	4,350	btu/lb – permit application
TDF Energy Content	16,100	btu/lb – permit application
Maximum TDF Use	5%	by weight (approx.)
Maximum TDF Use	15%	by BTU input – permit application
Maximum Biomass S	0.20%	permit application
Average Biomass S	0.06%	permit application
Maximum TDF S	2.00%	permit application
Average TDF S	1.50%	permit application
SOx to S ratio	2.00%	lb/lb EPD
Proposed BFB Control	30%	EPD
Proposed APC Control	70%	EPD
(Note: APC is dry scrubber w/ limestone or spray dry adsorber w/ CaO)		
Combined Control Effic.	79%	EPD

Uncontrolled SOx Formula:

[(% biomass x 1 lb x % S/100 x 2 lb SOx/lb/ 4350 BTU/lb) +
(% TDF x 1 lb x % S/100 x 2 lb SOx/lb / 16,100 BTU/lb)] x 1 mm btu/mmbtu

Controlled SOx Formula:

Uncontrolled SOx (lb/mbtu) x (1 – Combined Control Efficiency)

Cases	Uncontrolled SOx (lb/mmbtu)	Controlled SOx (lb/mmbtu)
100% Biomass – Avg. S	0.276	0.058
95% Bio + 5% TDF, Avg S	0.355	0.075
90% Bio + 10% TDF, Avg S	0.435	0.091
85% Bio + 15% TDF, Avg S	0.514	0.108
100% Biomass – Max. S	0.920	0.193
Max. S Bio 85% + Max. S TDF 15%	1.154	0.242

Proposed SOx Tier Limits	lb/mmbtu
24 Hour (Max/Max)	0.242
0.80 < Ucontrolled SOx < 1.00 (30 day Avg)	0.189
0.60 < Uncontrolled SOx < .80 (30 day Avg.)	0.147
0.40 < Uncontrolled SOx < .60 (30 day Avg.)	0.105
0.20 < Uncontrolled SOx < .40 (30 day Avg.)	0.063
Uncontrolled SOx < 0.20 (30 day Avg)	0.042