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April 16, 2008

334864.A1.01

Ms. Tyneshia Tate
Environmental Engineer
Stationary Source Permitting Program
Georgia Department of Natural Resources
Environmental Protection Division
Air Protection Branch
4244 International Parkway, Suite 120
Atlanta, GA 30354

Subject: Response to Comments
PSD Application No. 17700 dated September 27, 2007
Yellow Pine Energy Company, LLC

Dear Ms. Tate:

This letter is written in response to your questions and comments relative to the above referenced permit application submitted by Yellow Pine Energy Company, LLC (Yellow Pine Energy). This letter is written on behalf of our client, Yellow Pine Energy, to address questions posed in your February 15, 2008 letter to Mark S. Sajer of Summit Energy Partners, LLC. Our responses to your comments are provided below:

GAEPD Comment No. 1 - The application indicates that the auxiliary boiler will fire No. 2 fuel oil and propane. However potential to emit (PTE) calculations are provided only for No. 2 fuel. Yellow Pine must estimate emissions for propane combustion as well.

Response to GAEPD Comment No. 1: The PTE emissions for the auxiliary boiler during propane firing are presented in Attachment A. Emission factors from U.S. EPA *AP-42 Section 1.5* were used to calculate emissions.

GAEPD Comment No. 2 - Please provide a better description of tripper deck day silos. Be sure that PTE calculations have been estimated. If they have not, please provide this information.

Response to GAEPD Comment No. 2: The tripper deck day silos ("day silos") are located south of Boiler 1 on Figure 2-2 of the permit application. The exact design of the silo configuration is to be provided by the equipment supplier at a later date. For estimation purposes, Yellow Pine has planned for five (5) day silos for fuel and one silo for sand or limestone. The total volume of material handled will be the same whether the final design is four fuel silos instead of five, and no change in emissions is expected from what is presented in the application. Typically, four fuel silos will contain biomass and the fifth with either contain coal, Pet Coke or TDF, depending on availability and cost. Emissions from the day silos will be controlled by a single baghouse (Silo Baghouse). The tripper deck can be fed from either Fuel Process Building #1 (FPB1) or Fuel Process Building #2 (FPB2). The silo baghouse maximum hourly emissions are presented in Table 4-1 of the permit application and emission calculations are shown in Appendix E of the permit application.

GAEPD Comment No. 3 - What is the capacity of the fuel storage silo?

Response to GAEPD Comment No. 3: The total capacity of the fuel storage silos is approximately 550 tons.

GAEPD Comment No. 4 - How does Yellow Pine propose to bring control device(s) online after startup and/or shutdown?

Response to GAEPD Comment No 4: The baghouse will be used to control PM-10 emissions at all times when the boilers are combusting fuel since there will be no provision for a bypass to circumvent this device. Ammonia injection (for the SNCR) will be injected at the appropriate ratio when there is sufficient heat input to the boiler to sustain optimal temperatures in the hot zone of the boiler (normally 1500 °F to 1600 °F for a Fluidized Bed boiler), which will be monitored in the boiler control room by operators using a thermocouple connected to the boiler control system. Injection of ammonia at lower temperatures is not conducive to NO_X reduction. During shutdown, when the operator sees that temperatures are below this temperature range, ammonia injection will be discontinued to avoid excess ammonia emissions or "slip" to the atmosphere. It is expected that SNCR operation will begin approximately 4 hours after the beginning of the start-up cycle, which is the period when the start-up burners (on fuel oil or propane) will finish their cycle and biomass in increasing amounts is being fed to the boiler. During shutdown, the boiler temperature will fall below this temperature zone within approximately one to two hours of discontinuing fuel feed to the boiler.

During start-up, the dry scrubbing system will be brought up to temperature when the start-up burners are operating. The injection of limestone/lime will commence when the boiler operating on solid fuels reaches approximately thirty percent of rated fuel input and the steam turbine has sufficient flow to commence its operation. As the whole plant is ramped up, the injection rate for limestone/lime will also ramp up to follow stoichiometric proportions with the fuel. During shutdown, the injection of limestone/lime will be reduced in parallel with fuel consumption. During start-up and shutdown, the primary concern is fouling of the control devices due to corrosion from the condensation of water vapor and acid gasses (acid dew point). Therefore, injection of materials into the flue gas stream will require at a minimum that a stable temperature be achieved. A start-up and shutdown plan will be developed with the intent of maximizing the use of the control devices to limit emissions, while at the same time being protective of the control devices.

GAEPD Comment No. 5: Yellow Pine proposes to use No. 2 fuel oil and/or propane during start-up and shutdown of the fluidized bed boiler(s). However no PTE calculations were provided for this operation scenario. Please submit vender information and PTE calculations for operating the fluidized bed boiler(s) firing 100 percent No. 2 fuel oil and 100 percent propane. Also provide PTE calculations for firing the worst-case proposed combination of No. 2 fuel oil and propane. Yellow Pine must be sure that these operating scenarios are addressed by the facility's modeling.

Response to GAEPD Comment No. 5: This issue was discussed in Yellow Pine Energy's November 30, 2007 Response to Comments (Response to GAEPD Comment No. 6). The start-up will be initiated on either fuel oil or propane and not a mixture, due to a common feed system. The emissions stated in the response include emissions from propane during start-up conditions. With the exception of SO_2, emissions when firing fuel oil during start-up conditions will not vary significantly from the emissions during propane start-up. The SO_2 emissions will be directly related to the sulfur content of propane or fuel oil. During this initial start-up period on fuel oil, SO_2 emissions are expected to range from 0 to 20 lb/hr. SO_2 emissions should be very low at all times due to the very low sulfur content in the biomass that will be introduced in the boiler. SO_2 emissions are expected to be a function of the amount of fuel combusted. Pollutant emissions during start-up conditions are summarized in Table 1.

TABLE 1
SUMMARY OF PROJECTED EMISSIONS DURING COLD START-UP SEQUENCE

	Total Heat Input (MMBtu/hr)			Emissions (lb/hr) [a]	
Time (hours)	**From**	**to**	**Pollutant**	**From**	**to**
0 - 4	0	340.6	NO_X	0	71
			CO	0	13.3
			SO_2	0	20.0 [b, c]
			PM-10	0	6.0
4 - 8	340.6	728.4	NO_X	71	246
			CO	13.3	105
			SO_2	20.0	37.7 [d]
			PM-10	6.0	9.5
8 - 10	728.4	739.2	NO_X	246	132
			CO	105	198
			SO_2	37.7 [d]	40.3 [d]
			PM-10	9.5	18.0
8 - 10	728.4	739.2	NO_X	246	132
			CO	105	198
			SO_2	37.7 [d]	40.3 [d]
			PM-10	9.5	18.0

TABLE 1
SUMMARY OF PROJECTED EMISSIONS DURING COLD START-UP SEQUENCE

Time (hours)	Total Heat Input (MMBtu/hr) From	Total Heat Input (MMBtu/hr) to	Pollutant	Emissions (lb/hr) [a] From	Emissions (lb/hr) [a] to
10+	739.2	1529	NO_X	132	153
			CO	198	459
			SO_2	40.3 [d]	91.7 [d]
			PM-10	18.0	50.5

Note:
[a] These emissions are representative of the worst case emissions when firing either propane or fuel oil during startup.
[b] SO_2 emissions from fuel oil are based on a sulfur content of 0.05%.
[c] SO_2 emission factor is the maximum emission prior to the scrubber reaching sufficient temperature to operate with limestone/lime injection; thereafter based on 80% scrubber control efficiency.
[d] SO_2 emissions are based on worst case start-up fuel (fuel oil) and biomass.

Source: Manufacturer supplied information (not a guarantee)

During boiler shutdown, emissions are expected to decrease with boiler load and be relatively proportional to the amount of fuel combusted in the boiler(s).

GAEPD Comment No. 6 - In what form will the tire-derived fuel (TDF) be fired (i.e. whole, chunked, etc) in the fluidized boiler(s)? Will the TDF be de-wired (i.e. belting removed) upon arrival at the plant? Will Yellow Pine have to conduct any processing of the TDF before firing it in the fluidized boiler(s)? If so, what type of processing will Yellow Pine conduct?

Response to GAEPD Comment No. 6: The form of TDF is "95% metal-free TDF", which means the waste tires have been stripped of metal wires and cut into chunks, approximately 1 cubic inch in size. This TDF specification is based on a commercial vendor's standard. The TDF will be delivered to the site in a form ready for combustion. No additional processing will be required.

GAEPD Comment No. 7 - Yellow Pine must review and evaluate hybrid and dry cooling towers as Best Achievable Control Technology (BACT) for the cooling tower operation.

Response to GAEPD Comment No. 7: The BACT aspect of cooling tower operation is PM emissions, which result from a small amount particles that may become entrained in the cooling tower exhaust as cooling tower "drift". The annual emissions of PM from the cooling tower are estimated to be relatively small, 0.65 tons/year. Yellow Pine Energy believes that hybrid/dry cooling towers are not justified as BACT for the following reasons: a) Due to the ambient conditions in the southeastern United States, theses systems are ineffective and generally not used except for small or limited applications, b) The limited amount of space available at the proposed Facility for building cooling towers. Hybrid/dry cooling tower systems would require more space than the proposed wet system, and c) The high costs associated with these systems.

The Pier Report ("Comparison of Alternate Cooling Technologies for California Power Plants.", EPRI, Palo Alto, CA., and California Energy Commission, Sacramento, CA, February 2002) gives a range of $2.7 to $4.1 million for wet systems and from $18 to $47 million for dry systems for a nominal 500 MWe facility. Since this report was published, the cost of cooling towers has escalated by approximately 60% or $4.3 to $6.6 million for wet systems and $29 to $75 million for dry systems for a nominal 500 MWe facility. The Pier Report is available at the following link: www.energy.ca.gov/reports/2002-07-09_500-02-079F.PDF. The study found that hybrid systems and dry cooling systems can reduce power plant water requirements significantly. However, in comparison to wet cooling system, the use of the alternate technologies will have significantly greater capital costs for the cooling system components. In addition, hybrid and dry cooling systems may suffer reduced efficiency when high ambient air temperatures and humidity occur as is prevalent in the southeastern United States. Most dry systems are considered marginal in hot climates and significantly more cooling tower cells (and space) are necessary when using dry systems.

A more recent analysis indicates the capital cost to be approximately $39 million and $45 million for a hybrid cooling tower system and a dry system, respectively. The data was developed for a proposed 250 MW coal-fired plant. Scaling this data to 110 MWs implies an installed cost of $17.3 to $20.0 million.

As mentioned earlier, hybrid and dry cooling systems will be greatly affected by the weather conditions in South Georgia, where summers are characterized as hot and humid. These types of cooling systems lose effectiveness during the time when electricity demand is highest, potentially negatively impacting Yellow Pine Energy's reliability and output. Additionally, the dry cooling tower system will require a larger area due to the additional number of cells that will be required. The proposed Facility has a limited amount of space. For these reasons, Yellow Pine Energy believes that hybrid and dry cooling tower are neither appropriate nor feasible for this Facility.

GAEPD Comment No. 8 - Yellow Pine, for every pollutant, must rank each BACT by efficiency and provide a cost analysis for each technically feasible control technology eliminated based on cost. The cost analyses shall not include costs associated catalyst disposal or any other solid waste disposal; but shall be adjusted down for tax incentives, etc. For nitrogen oxides (NOx) BACT, Yellow Pine must lists each proposed BACT and rank them by control efficiency. Yellow Pine must provide a cost analysis for each technically feasible NOx control eliminated on cost as discussed above. For example, Yellow Pine must perform a cost analysis for selective catalytic reduction (SCR). In the case of SCR, Yellow Pine may not consider the cost of catalyst disposal in its cost analysis. This may be considered in environmental impacts.

Response to GAEPD Comment No. 8: In the application, Yellow Pine Energy provided a complete BACT assessment for each pollutant, with the exception of a cost analysis for NO_X control using SCR. As noted in the application, an SCR system inserted into the post-combustion section of a fluidized bed boiler is not considered to be technically feasible given the expected amount of plugging from ash carryover, poisoning from combustion byproducts of wood waste, and deactivation. Deactivation occurs when the calcium carbonate in wood ash combines with water vapor and coats the catalyst, thereby deactivating it. Unlike PC coal plants, where the ash is very fine, wood fuels are chunky which cause ash plugging. While biomass is an ideal fuel environmentally, its chemical composition includes significant amounts of chlorine and potassium ions, which become combustion byproducts. About thirty percent (30%) of wood ash is calcium carbonate, which coats the adsorbing catalyst surface thereby deactivating the system. Therefore, Yellow Pine Energy believes that its SCR determination in the Permit Application Report submitted in October 2007 is valid.

Based on discussions with fluidized boiler manufacturers, Yellow Pine Energy was able to validate its findings based on actual operating experience with an approximate 30 MWe fluidized bed boiler. The boiler attempted to operate with as SCR system installed in the post-combustion zone of the boiler. However, repeated SCR failure/deactivation, pressure instabilities due to ash plugging, and a high unplanned outage rate led to the removal of the SCR system. The boiler was placed back into service ultimately with a SNCR system (ammonia injection only) for NO_X control.

Another possible operating scenario is placing the SCR at the back end of the pollution control system (i.e., after the particulate control device). Under this operating scenario, the flue gas would need to be reheated to the optimal temperature for proper SCR operation, which is approximately 650 °F. The flue gas temperature of a fluidized bed boiler is already low, to limit thermal NO_X, and by the time the flue gas exits the baghouse, the flue gas temperature is much lower than the optimal temperature for an SCR system. While NOx emissions would be decreased, the installation of an SCR system in this type of configuration would require the installation of a duct burner and associated reheat system to increase the flue gas to an acceptable temperature, thus increasing the emissions of SO_2, PM-10, CO, and VOC by an estimated 50.1 tpy, 16.7 tpy, 35.2 tpy, and 1.67 tpy, respectively, based on fuel oil firing in a duct burner and steam generator. Based on a NO_X emission rate of 0.07 lb/MMBTU (68% removal efficiency for the SCR), the incremental cost effectiveness of the "back-end" SCR system would be approximately $63,400/ton when compared to the combustion controls alternative. Based on the large increase in annualized cost, Yellow Pine Energy does not feel it is either appropriate or economically justified to construct the boiler with a "back-end" SCR control system.

"Back-End" SCR System

In this configuration, the SCR is placed after the baghouse and after a reheat system, which is designed to raise the flue gas temperature to approximately 650 °F. Ammonia is injected and mixed with the flue gas before the mixture enters the SCR reactor. The ammonia reduces NO_X to nitrogen and water. Natural gas is not available at the proposed Facility; therefore, the in-duct burner will have to be fired with No. 2 Fuel Oil or propane. The fuel oil scenario presents the worst case for SO_2 emissions. The combustion of fuel oil or propane will increase emissions of NO_X, PM-10, CO, VOC and SO_2 from the Facility. Emissions of NO_X, PM-10, and SO_2 from the in-duct burner will be uncontrolled due to the location of the duct burner, downstream of the pollution control devices.

"Back-End" SCR BACT Findings

Based on information available from vendors, a "back-end" SCR system will increase the cost of the boiler by approximately $27,225,000. Total annualized costs associated with the "back-end" SCR system, electricity, maintenance labor and materials, ammonia costs, cost associated with reheating the gas stream, catalyst replacement, capital recovery, and indirect operating costs are estimated to be approximately $64,590,200/year. Based on an annual reduction in NO_X emissions of 1,019 tpy (1,488 tpy – 469 tpy) compared to the combustion controls alternative, the incremental cost effectiveness of the "back-end" SCR system would be approximately $63,400. Detailed cost estimates are provided in Attachment B.

The "back-end" SCR control system is not economically justified. Additionally, the inclusion of a reheat system for the "back-end" SCR system will increase the Facility's heat input by 224.9 MMBtu/hr and require the combustion of additional fuel oil or propane. The combustion of these fuels is contrary to the renewable energy nature of the project.

GAEPD Comment No. 9 - What is the engine type (i.e. two-stroke, four-stroke, etc.) for the proposed emergency engine and fire water pump? Are they rich burn or lean burn engines?

Response to GAEPD Comment No. 9: Yellow Pine is planning to install an emergency generator similar to the Cummins KTA50 Series Engine, Model DFLE and a fire pump engine similar to the Caterpillar Fire Pump Engine Model 3406B. The Cummins and Caterpillar engines are four-stroke. The emergency generator and fire pump engines will utilize clean ultra-low sulfur fuel oil and good combustion techniques to minimize emissions. These engines will be purchased based on the specification that they will meet the EPA non-road emission standards in force at the time of procurement, which at this time are specified in 40 CFR, Subpart IIII. The emergency generator will comply with the applicable requirements in the National Emission Standards for Hazardous Air Pollutants (NESHAP) for stationary reciprocating internal combustion engines (40 CFR 63, Subpart ZZZZ). This regulation generally applies to engines greater than 500 brake horsepower (bhp) that are located at a major source of HAP emissions. Additional information on these engines is included in Attachments C and D.

GAEPD Comment No. 10 - To date, has Yellow Pine determined if the fire pump stationary engine has a rated speed greater than 2,650 revolutions per minute (RPM)? What is the displacement, in terms of liters per cylinder, for the fire pump and generator engines?

Response to GAEPD Comment No. 10: The maximum RMP on the Caterpillar Fire Pump Engine is listed as 2300. The displacement on the Caterpillar and Cummins engines are 14.6 liters and 50.3 liters, respectively.

GAEPD Comment No. 11 - Fugitive emissions estimates consistently cite a *Technical Guide to Estimate Fugitive Dust*. However, no such document could be easily located. Please provide a copy of this document for the Division's review.

Response to GAEPD Comment No. 11: The subject report is DOE report Number DOE/RG/10312-1 (Volume 2). Volume 1 is a Summary Document. It is available from the National Technical Information Service (NTIS). A bibliography of the report is located at the following link: http://www.osti.gov/energycitations/product.biblio.jsp?osti_id=5934853. A copy of this document is being sent to EPD separately.

GAEPD Comment No. 12: Fugitive emissions estimates indicate batch dumping device capacities citing Erie Strayer Co. Please provide an explanation and associated documentation for the values provided.

Response to GAEPD Comment No. 12: The device is the clam shell bucket which is used to unload barges into a collection hopper. A drawing of the type of clam-shell bucket used in the emissions calculations is included as Attachment E. The clam-shell bucket Model No. XLR6 has a 6 cubic yard capacity. The clam-shell bucket will be used to unload raw materials from docked barges and to load a hopper. The hopper will be on a conveyor and will transport the raw materials up the river escarpment. A detailed discussion of the raw materials handling processes is included in Section 2 of the Permit Application Report and emission calculations are included in Appendix E of the permit application report.

GAEPD Comment No. 13 - Calculations of biomass fugitive emissions cite emission factors based on source classification codes (SCCs). This tends to indicate that the emission factors were obtained from the Environmental Protection Agency's (EPA's) Factor Information REtrieval (FIRE) Data System. However, no data was given so that this data could be reviewed and verified.

Response to GAEPD Comment No. 13: Emission factors for wood or biomass handling operations are not provided in Chapter 10 of AP-42, Wood Products Industry. The biomass handling emission factors in the Permit Application Report were previously used by CH2M HILL to estimate fugitive emissions for Title V permit applications for the forest products industry.

GAEPD Comment No. 14 - How were the quantities chosen for coal, petroleum coke, limestone, biomass, and/or sand when estimating fugitive emissions? How was the ash content chosen when ash silo fugitive emissions estimates were calculated?

Response to GAEPD Comment No. 14: The annual quantity of biomass used in the calculation of fugitive emissions was based on 100% biomass operation and the heat content of biomass (4350 Btu/lb) to determine the annual throughput. The annual quantities of coal and Pet Coke used in the calculation of fugitive emissions were based on the maximum fossil fuel input to the boiler (15% by Btu/hr heat input) to determine the annual throughput. The heat contents of coal and Pet Coke are 10,500 Btu/lb and 14,100 Btu/lb, respectively. The annual quantities of limestone and sand were based on Yellow Pine Energy's maximum expected annual throughput of these raw materials.

The maximum amount of ash generated was assumed to be for 100% biomass combustion because of the very large volume of biomass that will be burned. The percent of ash in the biomass was based on a fuel analysis of yellow pine trees ("*Thermal Data for Natural and Synthetic Fuels*", S. Gaur and T. Reed, Marcel Dekker, 1998).

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On behalf of Yellow Pine Energy, we request that you provide us with written acknowledgement that you have received this response, as well as concurrence that the information provided herein adequately addresses the questions and comments.

If you have any questions regarding the information provided herein or should you require any additional information, please contact me at (678) 530-4366 or by e-mail at rvaughn1@ch2m.com, or Mark Sajer at Summit Energy Partners at (908) 918-9151 or by e-mail at mark.sajer@sep-llc.com.

Sincerely,

CH2M HILL

Ronald Vaughn
Project Engineer

YellowPineEnergyLlc\334864\Corr\Response to Comments Dated 15-Feb-08.doc
Attachments
c: Mark S. Sajer/Summit Energy Partners, LLC
George Howroyd/CH2M HILL

Attachment A
Emission Calculations
Auxiliary Boiler Fired on Propane

1.0 Initial data needed for emission calculations for heating units fired with propane

Location (Bldg)	Rated Heat Input (MMBtu/hr)	Comment
Aux. Boiler	25.0	

Heat content of propane - 91,600 BTU/gal

2.0 Emission factors, from AP-42, Section 1.5 Tables 1.5-1 Commercial Heating Units

Constituent	Emission Factor
CO	3.2 lb/1000 gal fuel
NOx	19 lb/1000 gal fuel
PM-10	0.6 lb/1000 gal fuel
SO_2 (2)	0.020 lb/1000 gal fuel
VOC, non-methane	0.3 lb/1000 gal fuel

(1) The emission factor for PM-10 from propane heating units was assumed to represent PM-2.5 emissions.

(2) Emission factor for SO_2 = 0.1*S, where S = the weight % of sulfur in the propane. Assumed propane contains 0.2% sulfur by weight.

3.0 Calculation of Criteria Pollutant Emission Rates.

Constituent		Hourly Potential to Emit (lb/hr)	Annual Potential to Emit (lb/yr)
CO		0.87	218
NOx		5.19	1,296
PM-10		0.16	40.9
SO_2		0.0055	1.36
VOC		0.08	20.5

3.1 Calculation of Hourly PTE

Emission Factor (lb/1000 gal) x Total Heat Input (MMBtu/hr) x 10^6 / (Heating Content (BTU/gal) x 1000) = Emissions (lb/hr)

3.2 Calculation of Annual PTE

Hourly PTE (lb/hr) x 250 hr/yr = Potential Emissions (lb/yr)

Attachment B
BACT Analysis
“Back-End” SCR

Attachment B

Yellow Pine Biomass Project - BACT Analysis

Post Particulate Device SCR w/ Aux. Firing for Control of NOx

Fluidized Bed Boiler

Control Efficiency (%)	68%

Facility Input Data

Item	Value
Operating Schedule	
Shifts per day	3
Hours per day	24
Days per week	7
Total Hours per year	8760
Economic Life, years	20
Interest Rate (%)	7
Source(s) Controlled	FB boiler(s)
Temperature (°F after reheat)	650
Total Flowrate (acfm)	829,000
NOx From CFB Operation (lb/hr)	340
NOx Emissions (tpy) from boiler	1,488.2
Site Specific Electricity Cost ($/kWh)	0.060
Site Specific Operating Labor Cost ($/hr)	$62.00
Site Specific Maint. Labor Cost ($/hr)	$62.00

Capital Costs

	Value	Basis
Direct Costs		
1.) Purchased Equipment Cost		
a.) Equipment cost + auxiliaries + HX	$16,500,000	$92/kW + $5M HX, A
b.) Instrumentation	$0	Included
c.) Sales taxes	$0	Exempt
d.) Freight	$0	Included
Total Purchased equipment cost, (PEC)	$16,500,000	B
2.) Direct installation costs		
a.) Foundations and supports	$825,000	0.10 x B
b.) Handling and erection	$3,300,000	0.20 x B
c.) Electrical	$165,000	0.01 x B
d.) Piping	$165,000	0.01 x B
e.) Insulation for ductwork & painting	$165,000	0.01 x B
f.) Stack modification	$330,000	0.02 x B
Total direct installation cost	$4,950,000	0.30 x B
3.) Site preparation	NA	As Required, SP
4.) Buildings	NA	As Required, Bldg.
Total Direct Cost, DC	$21,450,000	1.30B + SP + Bldg.
Indirect Costs (installation)		
5.) Engineering	$330,000	0.02 x B
6.) Construction and field expenses	$825,000	0.05 x B
7.) Contractor fees	$1,650,000	0.10 x B
8.) Start-up	$330,000	0.02 x B
9.) Performance test	$165,000	0.01 x B
10.) Contingencies	$2,475,000	0.15 x B
Total Indirect Cost, IC	$5,775,000	0.35 x B + Other
Total Capital Investment (TCI) = DC + IC	**$27,225,000**	**1.61B + SP + Bldg. + Other**

Attachment B

Yellow Pine Biomass Project - BACT Analysis

Post Particulate Device SCR w/ Aux. Firing for Control of NOx

Fluidized Bed Boiler

Control Efficiency (%)	68%

Annual Costs

Item	Value	Basis	Source
1) Electricity			
Fan Power Requirement (kW)	1,440	15" Δp per unit 96kW/in	Estimate
Electric Power Cost ($/kWh)	0.060		
Cost ($/yr)	$756,864		
2) Operating Costs			
Operating Labor Requirement (hr/shift)	1	1 hour per shift	Estimate
Unit Cost ($/hr)	$62.00	Facility Data	Estimate
Labor Cost ($/yr)	$67,700		
3) Ammonia Costs ($/lb)	0.20		Estimate
Hourly Requirerment (Lbs/hour)	128	@ 1.02 NH_3/NOx Ratio	
Annual requirement (Lbs/year)	1,121,982		
Total Ammonia Costs ($/year)	$224,396		
4) Reheat			
Supplemental firing (MMBtu/hr)	224.9	Flue gas from 500 F to 650 F	Calculation
Heating value of #2 Fuel Oil (Btu/gal)	140,000		
Low Sulfur Fuel Oil cost ($/gal incl. tax & delivery)	$4.15		
Supplemental firing Cost	$58,400,104.3		
Total Cost	$58,400,104		
Total Operating Costs	**$59,449,065**		Estimate
4) Supervisory Labor			
Cost ($/yr)	$10,160	15% Operating Labor	OAQPS
5) Maintenance			
Maintenance Labor Req. (hr/year)	182.5	1/2 hour per day	Estimate
Catalyst Replacement Labor Req. (hr/yr)	586.7	8 men for 220 hours	Estimate
Unit Cost ($/hr)	$62.00	Facility Data	Estimate
Labor Cost ($/yr)	$47,690		
Material Cost ($/yr)	$47,690	100% of Maintenance Labor	OAQPS
Total Cost ($/yr)	$95,380		
6) Catalyst Replacement			
Catalyst Cost ($)	$4,440,000	Catalyst @ $370/cf & 12,000 cf	Estimate
Sales Tax ($)	$0	0% Sales Tax	
Catalyst Life (yrs)	3	n	Estimate
Interest Rate (%)	7	i	
CRF	0.38	Amortization of Catalyst	OAQPS
Annual Cost ($/yr)	$1,691,870	(Volume)(Unit Cost)(CRF)	
7) Indirect Annual Costs			
Overhead	$103,940	60% of O&M Costs	OAQPS
Administration	$544,500	2% of Total Capital Investment	OAQPS
Property Tax	$272,250	1% of Total Capital Investment	OAQPS
Insurance	$272,250	1% of Total Capital Investment	OAQPS
Capital Recovery	$2,150,740	20 yr life; 7% interest (-cat. cost)	OAQPS
Total Indirect ($/yr)	$3,343,680		

Total Annualized Cost ($/yr)	**$64,590,200**
Total Controlled (tpy)	**1019.4**
Cost Effectiveness ($/ton)	**$63,400**

Attachment C
Emergency Generator Specifications

Diesel Generator Set
KTA50 Series Engine

900-1500kW 60Hz
1000-1290kW 50Hz

Optional Features Shown

Description

This Cummins Power Generation commercial generator set is a fully integrated power generation system, providing optimum performance, reliability and versatility for stationary standby, prime power and continuous duty applications.

This generator set is designed in facilities certified to ISO9001.

This generator set is manufactured in facilities certified to ISO9001 or ISO9002.

The Prototype Test Support (PTS) program verifies the performance integrity of the generator set design. Cummins Power Generation products bearing the PTS symbol meet the prototype test requirements of NFPA 110 for Level 1 systems.

All low voltage models are CSA certified to product class 4215-01.

The generator set is available Listed to UL2200, Stationary Engine Generator Assemblies. The PowerCommand control is Listed to UL508 - Category NITW7 for U.S. and Canadian usage. Circuit breaker assemblies are UL489 Listed for 100% continuous operation and also UL869A Listed Service Equipment.

Features

- **Cummins® Heavy-Duty Engine** - Rugged 4-cycle industrial diesel delivers reliable power, low emissions, and fast response to load changes.
- **Permanent Magnet Generator (PMG)** - Offers enhanced motor starting and fault clearing short circuit capability.
- **Alternator** - Several alternator sizes offer selectable motor starting capability with low reactance 2/3 pitch windings; low waveform distortion with non-linear loads, fault clearing short-circuit capability, and class F or H insulation.
- **Control System** - The PowerCommand™ electronic control is standard equipment and provides total genset system integration, including automatic remote starting/stopping, precise frequency and voltage regulation, alarm and status message display, AmpSentry™ protection, output metering, auto-shutdown at fault detection, and NFPA 110 compliance.
- **Cooling System** - Standard integral set-mounted radiator system, designed and tested for rated ambient temperatures, simplifies facility design requirements for rejected heat.
- **Structural Steel Skid Base** - Robust skid base supports the engine, alternator, and radiator.
- **Warranty and Service** - Backed by a comprehensive warranty and worldwide distributor network.

	Standby Rating		Prime Power Ratings		Continuous Ratings		Data Sheets	
Model	**60 Hz** **kW** (kVA)	**50 Hz** **kW** (kVA)	**60 Hz** **kW** (kVA)	**50 Hz** **kW** (kVA)	**60 Hz** **kW** (kVA)	**50 Hz** **kW** (kVA)	**60 Hz**	**50 Hz**
DFLB	**1100** (1375)		**900** (1125)				**D-3251**	
DFLC	**1250** (1563)	**1120** (1400)	**1100** (1375)	**1000** (1250)			**D-3252**	**D-3253**
DFLE	**1500** (1875)	**1290** (1613)	**1250** (1563)	**1100** (1375)			**D-3234**	**D-3237**

Generator Set Specifications

Governor Regulation Class	ISO8528 Part 1 Class G3
Voltage Regulation, No Load to Full Load	± 0.5%
Random Voltage Variation	± 0.5%
Frequency Regulation	Isochronous
Random Frequency Variation	± 0.25%
Radio Frequency Emissions Compliance	IEC 801.2 through IEC 801.5; MIL STD 461C, Part 9

Engine Specifications

Design	4 cycle, V-block, turbocharged and low temperature after-cooled
Bore	158.8 mm (6.25 in.)
Stroke	158.8 mm (6.25 in.)
Displacement	50.3 litres (3067 in^3)
Cylinder Block	Cast iron, 60°V 16 cylinder
Battery Capacity	1800 amps minimum at ambient temperature of 32°F (0°C)
Battery Charging Alternator	55 amps
Starting Voltage	24 volt, negative ground
Fuel System	Direct injection: number 2 diesel fuel
Fuel Filter	Dual element, 10 micron filtration, spin on fuel filters with water separator
Air Cleaner Type	Dry replaceable element
Lube Oil Filter Type(s)	Four spin-on, combination full flow and bypass filters
Standard Cooling System	104°F (40° C) ambient radiator

Alternator Specifications

Design	Brushless, 4 pole, revolving field
Stator	2/3 pitch
Rotor	Single bearing, flexible disc
Insulation System	Class H
Standard Temperature Rise	150º C Standby
Exciter Type	PMG (Permanent Magnet Generator)
Phase Rotation	A (U), B (V), C (W)
Alternator Cooling	Direct drive centrifugal blower fan
AC Waveform Total Harmonic Distortion	< 5% no load to full linear load, <3% for any single harmonic
Telephone Influence Factor (TIF)	<50 per NEMA MG1-22.43
Telephone Harmonic Factor (THF)	<3

Available Voltages

60 Hz Line – Neutral / Line - Line		50 Hz Line – Neutral / Line – Line	
☐ 220/380	☐ 277/480	☐ 220/380	☐ 254/440
☐ 255/440	☐ 347/600	☐ 230/400	☐ 1905/3300
	☐ 2400/4160	☐ 240/415	

Note: Consult factory for other voltages.

Generator Set Options

Engine
- ☐ 208/240/480V Thermostatically controlled coolant heaters for ambients above 4.5°C (40°F)
- ☐ 208/240/480V Thermostatically controlled coolant heaters for ambients below 4.5°C (40°F)
- ☐ Bypass oil filter
- ☐ Dual 120V, 300W lube oil heaters
- ☐ Dual 208/240V, 300W lube oil heaters
- ☐ Dual 480V, 300W lube oil heaters
- ☐ Heavy duty air cleaners with service indicator

Control Panel
- ☐ 120/240V, 100 Watt control anti-condensation space heater
- ☐ Paralleling configuration
- ☐ Remote fault signal package
- ☐ Run relay package
- ☐ Exhaust pyrometer
- ☐ Fuel-pressure gauge
- ☐ Ground fault indication

Alternator
- ☐ 80°C rise alternator
- ☐ 105°C rise alternator
- ☐ 125°C rise alternator
- ☐ 120/240V, 300 Watt anti-condensation heater

Exhaust System
- ☐ Industrial-grade exhaust silencer
- ☐ Residential-grade exhaust silencer
- ☐ Critical-grade exhaust silencer
- ☐ Exhaust packages

Cooling System
- ☐ Radiator, 50°C ambient
- ☐ Remote radiator cooling
- ☐ Heat exchanger cooing

Generator Set
- ☐ AC entrance box
- ☐ Batteries
- ☐ Battery charger
- ☐ Circuit breaker – set mounted
- ☐ Disconnect switch – set mounted
- ☐ Paralleling accessories
- ☐ PowerCommand® Network
- ☐ Remote annunciator panel
- ☐ Spring isolators
- ☐ 2 year warranty
- ☐ 5 year warranty
- ☐ 10 year major components warranty

Note: Some options may not be available on all models, consult factory for availability.

Control System

PowerCommand Control with AmpSentry^{TM} Protection

- The PowerCommand Control is an integrated generator set control system providing governing, voltage regulation, engine protection, and operator interface functions.
- PowerCommand Controls include integral AmpSentry protection. AmpSentry provides a full range of alternator protection functions that are matched to the alternator provided.
- Controls provided include Battery monitoring and testing features, and Smart-Starting control system.
- InPower PC-based service tool available for detailed diagnostics.
- PCCNet interface. Available with Echelon LonWorks^{TM} network interface.
- NEMA 3R enclosure.
- Suitable for operation in ambient temperatures from -40C to +70C, and altitudes to 13,000 feet (5000 meters).
- Prototype tested; UL, CSA, and CE compliant.

AmpSentry AC Protection

- Overcurrent and short circuit shutdown
- Overcurrent warning
- Single & 3-phase fault regulation
- Over and under voltage shutdown
- Over and under frequency shutdown
- Overload warning with alarm contact
- Reverse power and reverse Var shutdown
- Excitation fault

Engine Protection

- Overspeed shutdown
- Low oil pressure warning and shutdown
- High coolant temperature warning and shutdown
- High oil temperature warning (optional)
- Low coolant level warning or shutdown
- Low coolant temperature warning
- High and low battery voltage warning
- Weak battery warning
- Dead battery shutdown
- Fail to start (overcrank) shutdown
- Fail to crank shutdown
- Redundant start disconnect
- Cranking lockout
- Sensor failure indication

Operator Interface

- OFF/MANUAL/AUTO mode switch
- MANUAL RUN/STOP switch
- Panel lamp test switch
- Emergency Stop switch
- Alpha-numeric display with pushbutton access, for viewing engine and alternator data and providing setup, controls, and adjustments
- LED lamps indicating genset running, not in auto, common warning, common shutdown
- (5) configurable LED lamps
- LED Bargraph AC data display (optional)

Alternator Data

- Line-to-line and line-to-neutral AC volts
- 3-phase AC current
- Frequency
- Total and individual phase kW and kVA

Engine Data

- DC voltage
- Lube oil pressure
- Coolant temperature
- Lube oil temperature (optional)

Other Data

- Genset model data
- Start attempts, starts, running hours
- KW hours (total and since reset)
- Fault history
- Load profile (hours less than 30% and hours more than 90% load)
- System data display (optional with network and other PowerCommand gensets or transfer switches

Governing

- Integrated digital electronic isochronous governor
- Temperature dynamic governing
- Smart idle speed mode
- Glow plug control (some models)

Voltage Regulation

- Integrated digital electronic voltage regulator
- 3-phase line to neutral sensing
- PMG (Optional)
- Single and three phase fault regulation
- Configurable torque matching

Control Functions

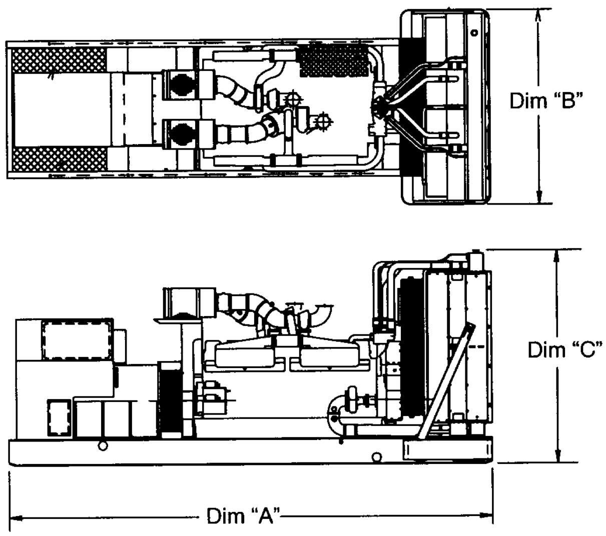
- Data logging on faults
- Fault simulation (requires InPower)
- Time delay start and cooldown
- Cycle cranking
- PCCNet Interface
- (4) Configurable customer inputs
- (4) Configurable customer outputs
- (8) Configurable network inputs and (16) outputs (with optional network)

Options

[ ] Analog AC Meter Display
[ ] Thermostatically Controlled Space Heater
[ ] Key-type mode switch
[ ] Ground fault module
[ ] Engine oil temperature
[ ] Auxiliary Relays (3)
[ ] Echelon LonWorks interface
[ ] Digital input and output module(s) (loose)
[ ] Remote annunciator (loose)

Ratings Definitions

Standby:	Prime (Unlimited Running Time):	Base Load (Continuous):
Applicable for supplying emergency power for the duration of normal power interruption. No sustained overload capability is available for this rating. This rating is applicable to installations served by a reliable normal utility source. This rating is only applicable to variable loads with an average load factor of 80 percent of the standby rating for a maximum of 200 hours of operation per year and a maximum of 25 hours per year at 100% of its standby rating. The standby rating is only applicable to emergency and standby applications where the generator set serves as the back up to the normal utility source. No sustained utility parallel operation is permitted with this rating. (Equivalent to Fuel Stop Power in accordance with ISO3046, AS2789, DIN6271 and BS5514). Nominally Rated.	Applicable for supplying power in lieu of commercially purchased power. Prime power is the maximum power available at a variable load for an unlimited number of hours. A 10% overload capability is available for limited time. (Equivalent to Prime Power in accordance with ISO8528 and Overload Power in accordance with ISO3046, AS2789, DIN6271, and BS5514). This rating is not applicable to all generator set models.	Applicable for supplying power continuously to a constant load up to the full output rating for unlimited hours. No sustained overload capability is available for this rating. Consult authorized distributor for rating. (Equivalent to Continuous Power in accordance with ISO8528, ISO3046, AS2789, DIN6271, and BS5514). This rating is not applicable to all generator set models.



This outline drawing is to provide representative configuration details for Model series only.

See respective model data sheet for specific model outline drawing number.

Do not use for installation design

Model	Dim “A” mm (in.)	Dim “B” mm (in.)	Dim “C” mm (in.)	Dim “D” mm (in.)	Set Weight* dry kg (lbs)	Set Weight* wet kg (lbs)	w/Tank Dry weight kg (lbs)	w/Tank Wet weight kg (lbs)
DFLB	**5652** (223)	1894 (75)	2515 (99)		9573 (21105)	9924 (21877)		
DFLC	**5652** (223)	**2274** (90)	2383 (94)		9719 (21247)	**10053** (22162)		
DFLE	**5652** (223)	**2274** (90)	2514 (99)		10350 (22817)	**10788** (23784)		

***Note: Weights represent a set with standard features. See outline drawings for weights of other configurations. Dim “D” available only on models with sub-base fuel tank option.**

See your distributor for more information.

Power Generation

Cummins Power Generation
1400 73rd Avenue N.E.
Minneapolis, MN 55432 USA
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Fax: +1 (763) 574-5298
Email: ask.powergen@cummins.com
Web: www.cumminspowergeneration.com

Important: Back feed to a utility system can cause electrocution and/or property damage. Do not connect to any building's electrical system except through an approved device or after building main switch is open.

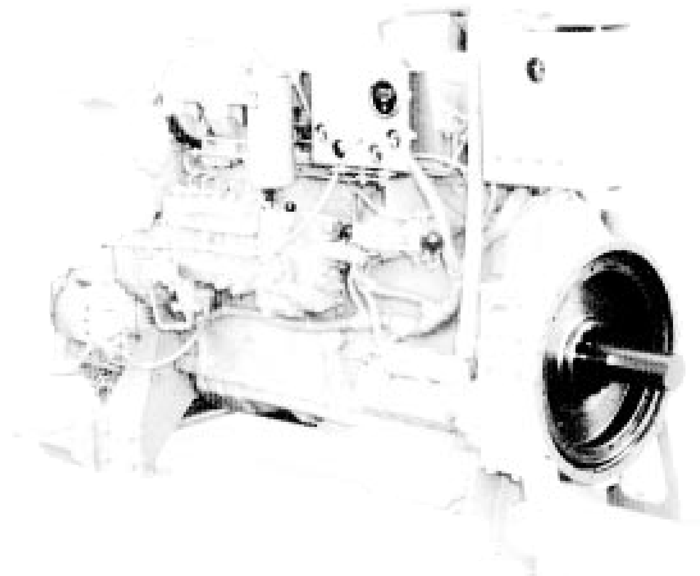
Attachment D
Fire Pump Engine Specifications

CATERPILLAR®

Fire Pump Engine

3406B

325-482 hp
242-360 kW



SPECIFICATIONS

In-line 6, 4-Stroke-Cycle Diesel
Turbocharged & Turbocharged-Aftercooled

Bore—in (mm)	5.4 (137)
Stroke—in (mm)	6.5 (165)
Displacement—cu in (L)	893 (14.6)
Rotation (from flywheel end)	Counterclockwise
Capacity for Liquids—U.S. gal (L)	
Cooling System* (T)	27.5 (104.1)
(TA)	29.2 (110.5)
Lube Oil System (refill)	9.0 (34.1)
Weight, Net Dry (approx)—lb (kg)	
Turbocharged	2,960 (1342)
Turbocharged-Aftercooled	3,240 (1469)

* Engine only. Capacity will vary with radiator size and use of cab heater.

STANDARD EQUIPMENT

Air cleaner, single-stage, dry
Alternator, charging, 24 Volt
Breather, crankcase
Cooler, lubricating oil, right side
Elbow, exhaust, dry, 6-inch
Filters
  fuel, left side
  lubricating oil, right side
  primary fuel
Flywheel
Flywheel housing, SAE No. 1
Flywheel stub shaft
Governor control, vernier
Governor, hydra-mechanical
Heat exchanger (installed)
Heater, jacket water (120/240 Volts)
Instrument panel, left side
  ammeter gauge, fuel pressure gauge, lubricating oil pressure gauge, tachometer, water temperature gauge
Lifting eyes
Manifolds, dry shielded
Oil filler and dipstick on right side
Oil pan, rear sump
Paint, red
Pumps
  fuel priming; fuel transfer; jacket water, gear-driven, centrifugal, right side
SAE standard rotation
Service meter, electric
Stop-start system, automatic
  (compatible with NFPA 20 requirements — energizable from either of two battery sources and capable of manual starter actuation)
Supports
Tank, expansion
Thermostats and housing
Torsional vibration damper
Turbocharger, dry shielded
Variable timing, automatic

CAT® DIESEL FIRE PUMP ENGINES

Factory designed—assembled—tested and delivered in a package that meets NFPA-20 regulations and more—supported 100% by your Caterpillar dealers.

FACTORY RUN-IN

All Cat® fire pump diesels are dynomometer tested at the factory to make sure they meet the certified rating standards. Your Caterpillar dealer can provide on-site inspection and training or instruction.

RELIABLE STARTING

Cat® fuel injection systems feature individual injection pumps for each cylinder and injector capsules with clog-resistant orifices. Injection system, along with a solenoid energized to shut down, assures quick, easy starting in case of emergency.

Factory Mutual System Approved

UL LISTED

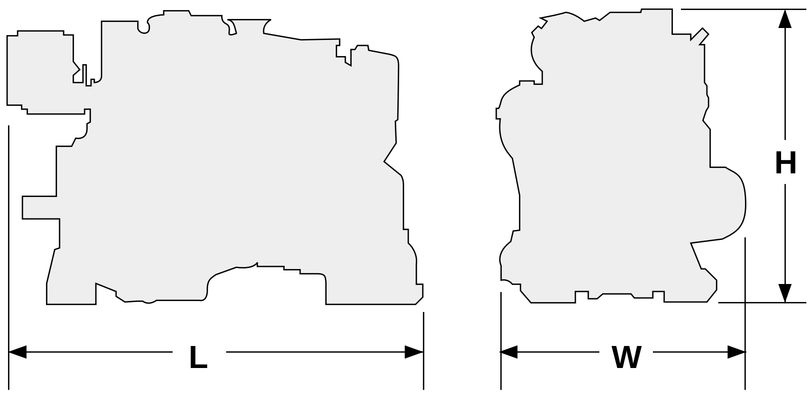
ULC

CATERPILLAR ENGINE FACILITIES ISO 9001 CERTIFIED

CATERPILLAR®

3406B FIRE PUMP ENGINE – 325-482 hp 242-360 kW

DIMENSIONS



LENGTH	in	mm
Turbocharged	76.3	(1939)
Turbocharged-Aftercooled	76.3	(1939)

WIDTH	in	mm
Turbocharged	46.3	(1175)
Turbocharged-Aftercooled	46.3	(1175)

HEIGHT	in	mm
Turbocharged	51.6	(1311)
Turbocharged-Aftercooled	51.8	(1316)

FUEL CONSUMPTION gal/h (liter/h)

	Turbocharged	Turbocharged-Aftercooled
1460 rpm	16.1 (60.9)	–
1750 rpm	18.3 (69.4)	22.3 (84.6)
1900 rpm	18.6 (70.5)	22.4 (84.9)
2100 rpm	18.6 (70.5)	23.6 (89.3)
2300 rpm	17.8 (67.3)	22.5 (85.2)

POWER RATING hp (kW)

1460 rpm	325 (242)	–
1750 rpm	370 (276)	460 (343)
1900 rpm	375 (280)	460 (343)
2100 rpm	375 (280)	482 (360)
2300 rpm	350 (261)	455 (339)

RATING CONDITIONS AND DEFINITIONS

Rating conditions are 300 ft (91.4 m) above sea level 29.61 in Hg or (0.7521 m Hg) at 77° F (25° C). Deductions in horsepower of 3% for each 1,000 ft (305 m) above 300 ft (91.4 m) and 1% for each 10° F (5.6° C) increase in ambient temperature above 77° F (25° C) are required as specified in NFPA No. 20.

Standby fire pump ratings represent the output which may be utilized to drive stationary fire pumps where the pumping equipment has been sized according to ULI, ULC, and FM procedures.

The International System of Units (SI) is used in the publication.

LEHQ5346 (7-95)
Supersedes LEHQ8570

Printed in U.S.A.

Attachment E
Clam-Shell Bucket
Drawing

D-76551

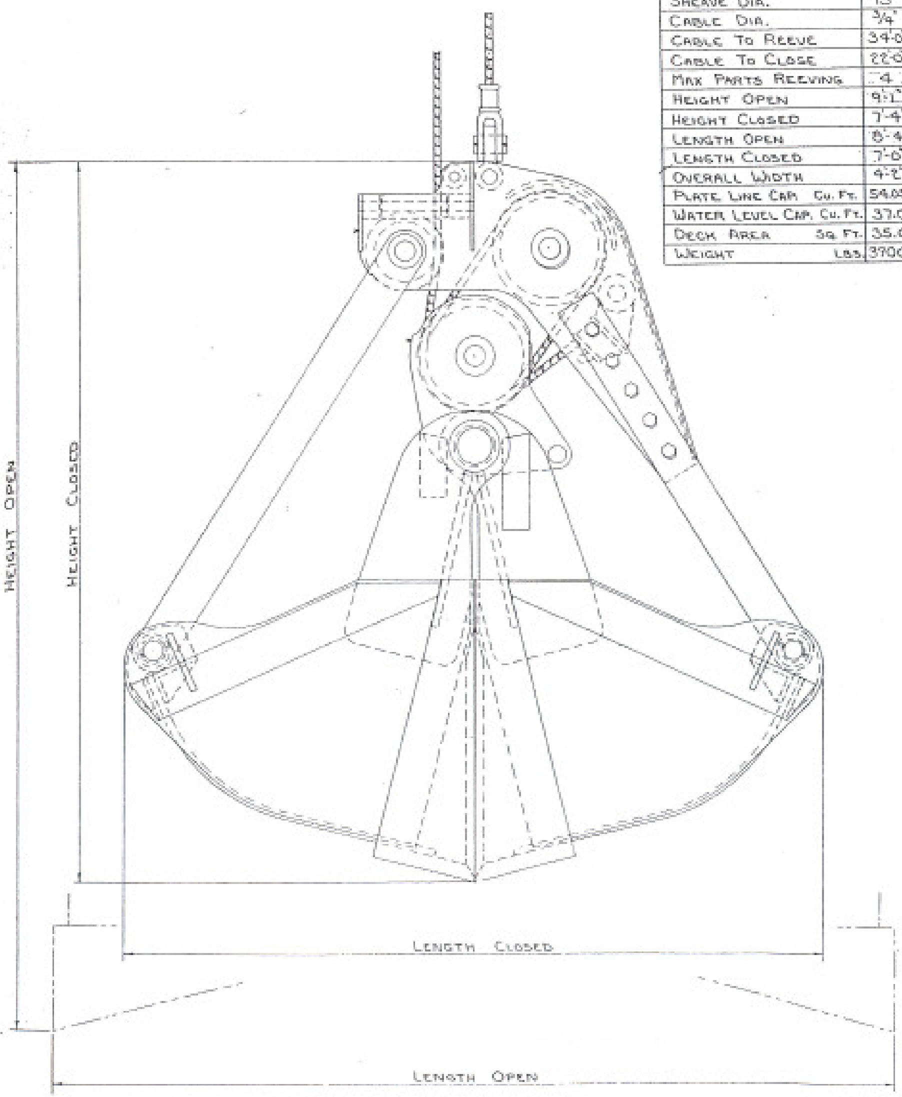
GENERAL DRAWING
XLR SERIES

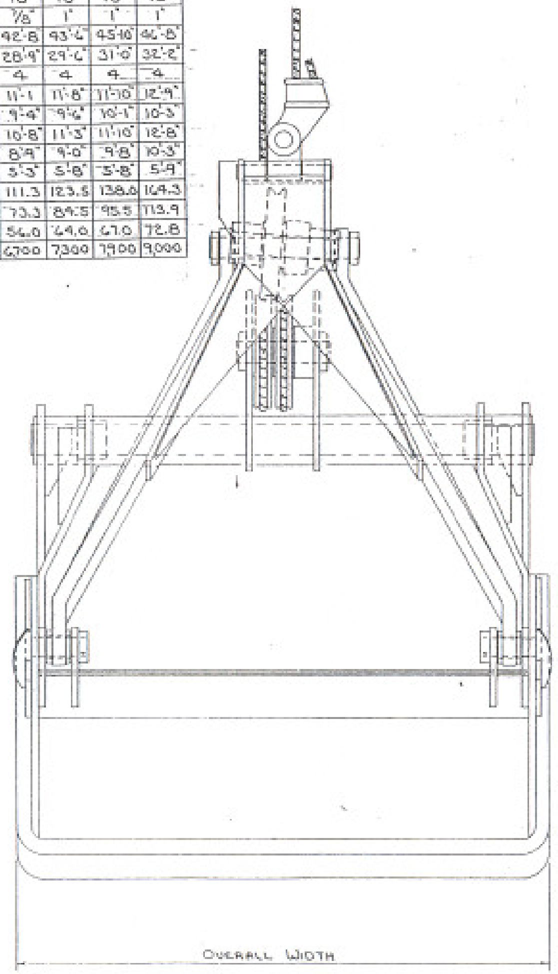
ITEM NO.	QTY.	DESCRIPTION	LENGTH FT.	LENGTH IN.	TOT. WT.	PIECE MARK

DRAWING D-76551

SPECIFICATIONS

MODEL	XLR2	XLR2½	XLR3	XLR3½	XLR4	XLR4½	XLR5	XLR6
SIZE CU. YD.	2	2½	3	3½	4	4½	5	6
SHEAVE DIA.	15"	15"	15"	18"	18"	18"	18"	18"
CABLE DIA.	3/4"	3/4"	3/4"	7/8"	7/8"	1"	1"	1"
CABLE TO REEVE	34'-0"	34'-6"	37'-8"	41'-0"	42'-8"	43'-6"	45'-10"	46'-8"
CABLE TO CLOSE	22'-0"	23'-0"	24'-10"	28'-0"	28'-9"	29'-6"	31'-0"	32'-2"
MAX PARTS REEVING	4	4	4	4	4	4	4	4
HEIGHT OPEN	9'-1"	9'-5"	9'-11"	10'-8"	11'-1	11'-8"	11'-10"	12'-9"
HEIGHT CLOSED	7'-4"	7'-7"	8'-0"	8'-8"	9'-4"	9'-6"	10'-1"	10'-3"
LENGTH OPEN	8'-4"	8'-9"	9'-7"	9'-11"	10'-8"	11'-3"	11'-10"	12'-8"
LENGTH CLOSED	7'-0"	7'-4"	7'-8"	8'-2"	8'-9"	9'-0"	9'-8"	10'-3"
OVERALL WIDTH	4'-2"	4'-10"	4'-11"	5'-3"	5'-3"	5'-8"	5'-8"	5'-9"
PLATE LINE CAP. CU. FT.	54.05	69.0	82.0	94.8	111.3	123.5	138.0	164.3
WATER LEVEL CAP. CU. FT.	37.0	46.9	55.8	64.4	73.3	84.5	95.5	113.9
DECK AREA SQ. FT.	35.0	42.5	47.1	52.0	56.0	64.0	67.0	72.8
WEIGHT LBS.	3700	4,400	5,000	6200	6700	7300	7900	9,000





ERIE STRAYER CO.
ERIE, PA.

ERIE BUCKET
GENERAL DRAWING
EXTRA LIGHT REHANDLER SERIES
2 CU. YD. — 6 CU. YD.

RAW FY

D-76551