DEP ROUTING AND TRANSMITTAL SLIP

TO: (NAME, OFFICE, LOCATION)

1. Jeffery Koerner

2.

3.

5.

PLEASE PREPARE REPLY FOR:

___ SECRETARY'S SIGNATURE

___ DIV/DIST DIR SIGNATURE

___ MY SIGNATURE

___ YOUR SIGNATURE

___ DUE DATE ___

ACTION/DISPOSITION

___ DISCUSS WITH ME

___ COMMENTS/ADVISE

___ REVIEW AND RETURN

___ SET UP MEETING

___ FOR YOUR INFORMATION

___ HANDLE APPROPRIATELY

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X FOR YOUR FILES

COMMENTS: Tallahassee Office / DEP Air Program Mail Station 5505

NOTE: THIS WAS LOST IN OUR MAIL SYSTEM. IT WAS RECEIVED BY FAX ON 8-30-99. JFK

FROM: WPBSED DATE: 12/23/99 PHONE: 276-6659

Maria

DEP 15-026 (12/93)

Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

August 23, 1999

RECEIVED 9937515

DEC 27 1999

BUREAU OF AIR REGULATION

Florida Department of Environmental Protection
New Source Review Section
2600 Blair Stone Road
Tallahassee, FL

Attention: Jeffery Koerner, P.E.

m,5/a 5505

RE: U.S. SUGAR – PSD PERMIT APPLICATION FOR BOILER NO. 4 AND THE SUGAR REFINERY AT THE CLEWISTON MILL
RESPONSE TO REQUEST FOR INFORMATION NO. 2

Dear Mr. Koerner:

This letter is in response to your draft completeness letter e-mailed to me on August 16 concerning U.S. Sugar's PSD Permit Application to modify operation of Boiler No. 4 and expand the sugar refinery operation at their mill located in Clewiston, Florida. This letter is organized in the same manner as your draft completeness letter. Responses to each item are presented below, numbered according to the original question numbers.

4. An analysis of the cost effectiveness of reducing SO_2 emissions by buying fuel oil with a sulfur content of less than 1.5 percent is presented in the attached tables. A summary of fuel costs and calculated emission rates for several scenarios is presented in Table 4-1. A cost efficiency evaluation of the following SO_2 emissions reduction options is presented in Tables 4-2 through 4-5:

   1. Replacing the current 1.5 percent sulfur No. 6 fuel oil burned with 0.7-percent sulfur No. 6 fuel oil, and storing it in the existing common storage tank used to supply Boiler Nos. 1, 2, 3, and 4.
   2. Replacing the current 1.5-percent sulfur No. 6 fuel oil burned with 0.7 percent sulfur No. 6 fuel oil, and storing it in a new storage tank.
   3. Replacing the current No. 6 fuel oil burned with No. 2 fuel oil with a sulfur content of 0.5 percent. This option would require a new storage tank (No. 6 and No. 2 fuel oil are not miscible) and replacement of the current oil burners in Boiler No. 4, which are not capable of firing No. 2 fuel oil.
   4. Replacing the current No. 6 fuel oil burned with No. 2 fuel oil with a sulfur content of 0.05 percent. This option would also require a new storage tank and burner replacement.

   It is noted that, for cost effectiveness calculations, the top-down BACT guidance document (draft) allows the use of past historical operation and emissions. Thus, even though Boiler No. 4 is permitted to burn 500,000 gal/yr of fuel oil, actual historic operation (last 3 years) indicates only about 100,000 gal/yr of fuel oil is burned. The actual fuel oil consumption and resulting SO_2 emissions were used for the cost effectiveness calculations.

The results of the analysis are shown in Table 4-6. Clearly, the cost efficiencies of the two options involving switching to No. 2 fuel oil are unreasonable (over $8,000 per ton of SO_2 removed). This is due to the relatively small reduction in SO_2 emissions (approximately 12 tons) measured against the capital cost of a new storage tank and replacement of the burners ($395,000). Option 2 was included at the request of FDEP. The only difference between Option 1 and Option 2 is that Option 1 employs the use of the existing common storage tank, while Option 2 includes installation of a new storage tank at a substantial cost to U.S. Sugar. It is emphasized that the installation of a new storage tank is not justified as it affords <u>no additional</u> SO_2 control over that afforded by Option 1, but increases the cost of SO_2 removal by nearly $5,000 per ton.

Given the costs associated with switching Boiler No. 4 to No. 2 fuel oil or adding another No. 6 fuel oil tank, U.S. Sugar requests that BACT be determined to be the use of No. 6 fuel oil with a sulfur content of 0.7 percent.

The potential reductions in SO_2 emissions that may be obtained by lowering the overall sulfur content of fuel oil fired in the common fuel oil tank was also analyzed. Based on the last 2 years of operation for Boiler Nos. 1 through 4, total fuel oil burning averaged 970,000 gal/yr, sulfur content averaged 2.3 percent, and SO_2 emissions averaged 192 TPY. Switching to 0.7-percent sulfur No. 6 fuel oil would, therefore, lower actual SO_2 emissions by about 134 TPY. The cost of such reduction, based on the information presented in Tables 4-1 through 4-6, would be approximately $700/ton of SO_2 removed (similar to Option 1 in the above analysis). It is cautioned, however, that the PSD rules do not bring the other boilers under the review requirements. The other boilers are not part of the proposed "modification". Only the modification itself (Boiler No. 4 and the sugar refinery) is subject to BACT.

In addition, the proposed project no longer results in an increase in SO_2 emissions of 350 TPY. Attached are revised tables which show the maximum short-term emissions (Table 2-1), the future maximum annual emissions (Table 2-2), the current baseline emissions (Table 3-3) and the net increase in emissions (Table 3-4) for Boiler No. 4. Also attached is a revised Table 1-1, which shows the total net increase in emissions for Boiler No. 4 and the sugar refinery. Tables 2-1 and 2-2 have been revised to reflect the 0.7-percent sulfur fuel oil, as well as a lower SO_2 limit for bagasse firing (refer to Item 5 below). These changes affect SO_2 and sulfuric acid mist emissions. Baseline emissions (Table 3-3) have been revised to correct some minor typographical errors. These changes are reflected in the revised Tables 1-1 and 3-4. Also attached are revised permit application form pages, which reflect these changes.

5. SO_2 removal is inherent to the process of combusting bagasse. The fly ash produced during bagasse firing is alkaline in nature and acts as a dry scrubbant adsorbing SO_2

from the exhaust stream. The fly ash, along with the adsorbed SO_2, is then removed by the scrubber. The alkaline nature of the fly ash also maintains the pH of the scrubber water between 5 and 8, further enhancing SO_2 removal. Evidence of the inherent removal of SO_2 is apparent on review of the SO_2 stack test results for Boiler No. 7 presented in our last correspondence. The only control equipment employed on Boiler No. 7 is an ESP, yet SO_2 removal efficiencies average 96 percent. As shown in the stack tests for Boiler No. 4, also presented in our last response, the average removal efficiency with the addition of a scrubber only increases to 97 percent. As such, monitoring the pH of the scrubber water is not necessary as an indicator of the efficiency of SO_2 control. It is noted that for air dispersion modeling purposes, a 75-percent SO_2 removal efficiency was assumed for Boiler Nos. 1, 2, and 3 for bagasse firing.

To the best of our knowledge, specific stack tests have not been performed to quantify the potential control effectiveness of maintaining or enhancing the alkaline scrubbing media. Based on the SO_2 stack tests performed on the wet scrubber sources at Clewiston, U.S. Sugar is willing to reduce the allowable SO_2 emission limit for bagasse to 0.1 lb/MMBtu, which allows an adequate safety margin above the actual test results. U.S. Sugar is also willing to conduct a stack test to once again verify that this emission limit is being met.

10. See our response to Item 5.

12. Using information from the last five stack tests the actual range for the scrubber pressure drop has historically ranged from 9 to 10 inches H_2O. Based on this actual operation, for which compliance with the particulate matter (PM) emission limit was demonstrated, the optimum range for pressure drop is 7 to 12 inches H_2O. As you have discovered in the Boiler No. 4 permit files, the scrubber manufacturer (Joy) based their PM emission guarantee on a pressure drop from 5 to 9 inches H_2O. U.S. Sugar, based on actual operating experience, typically operates slightly above this range to obtain better performance and improved PM removal.

13. As described in our previous response, there is no historic boiler oxygen concentration level data for Boiler No. 4. The boiler is not equipped with an oxygen monitor. Oxygen at the stack is measured during stack testing, but this oxygen level is not representative of boiler oxygen levels due to significant air infiltration into the exhaust gases between the boiler and the stack. The other boilers at the Clewiston mill that are similar to Boiler No. 4 (Boiler Nos. 1, 2, and 3) also do not have oxygen monitors.

    Boiler No. 8 at the Sugar Cane Growers Cooperative has an oxygen meter, and the O&M plan for the boiler requires that an alarm be triggered if the oxygen level in the boiler drops below 4 percent. The time the boiler operates with less than 4-percent oxygen must be logged. The O&M plan states that the goal is to maintain the flue gas oxygen content at or above 4 percent, to the extent practical without sacrificing proper boiler operation and consistent with meeting steam demands.

In consideration of the Department's desire to implement methods of potentially lowering CO and VOC emissions, U.S. Sugar is willing to install a flue gas oxygen monitor on Boiler No. 4 during the upcoming crop season. The flue gas oxygen content will be recorded on an hourly basis. It is proposed that data collection continue for three crop seasons, which will include stack testing for CO and VOC emissions in each of these three seasons. After this data collection, the data will be evaluated and an appropriate range of oxygen level established for the boiler. The oxygen monitor will then be configured to trip an alarm whenever the oxygen content falls outside the established range. Corrective actions would then be implemented to bring the oxygen level within the established range, consistent with proper boiler operation and meeting steam production demands.

In addition, U.S. Sugar agrees to lower their proposed VOC emission limit from the previous requested level of 1.5 lb/MMBtu to a more realistic 0.5 lb/MMBtu. Although there is no recent VOC test data for this boiler, U.S. Sugar believes this is a reasonable limit based on the boiler design. Revised calculation tallies are attached.

16. The GCRF has never been tested for SO_2 emissions, and such testing is not a requirement of the current permit. However, as we discussed, the SO_2 emissions are solely due to fuel oil combustion in the furnace and, therefore, there is no need to perform stack testing (fuel analysis should suffice). The critical parameters for operation of the afterburner on the GCRF is afterburner temperature, while pressure drop is critical on the venturi scrubber.

21. We are pursuing approval of the ISC-PRIME model through discussions with Cleve Holladay and EPA Region IV.

22. The questions received to date from the National Park Service (NPS) so far are answered below.

In regards to the comment that we have not provided a top-down BACT analysis for each pollutant, nor suggested a method to substantially reduce such emissions the following is provided. For SO_2, the response to Question 4 above should provide you with this information. For CO and VOC, there are no known or proven methods for reducing these emissions from an existing boiler, other than proper boiler operation. The response to Question 13 above provides a plan for acquiring to data to ultimately reduce emissions. However, data must first be collected and evaluated prior to implementing any specific actions. In regards to NO_x, emissions from this boiler are already very low (NO_x emissions averaged 0.08 lb/MMBtu) and do not warrant further reduction. Any measures to reduce CO and VOC emissions will likely increase NO_x emissions.

__Responses to NPS Comments:__

PSD Applicability

Baseline (actual) emission rate calculations for all regulated pollutants emitted from Boiler No. 4 were presented in Table 3-3 of the PSD permit application. A copy of Table 3-3 is attached for your review. These emission rate calculations are based on average operation of Boiler No. 4 during 1997 and 1998.

Due to the short operational history (less than 2 years), the sugar refinery and its proposed expansion were considered a new source in the PSD permit application. As such, emissions of VOC and PM associated with the proposed expansion of the sugar refinery were addressed in the PSD analysis.

In regards to emissions from the sugar mill and bagasse handling system, refer to the response to FDEP Comment 1 above.

Best Available Control Technology

Particulate Matter

The cost effectiveness (dollars per ton of PM removed) of an ESP is significantly less for Boiler No. 7 than for Boiler No. 4 for one main reason: Boiler No. 7 was a new boiler and, therefore, its uncontrolled emissions were the basis of the cost effectiveness calculations. Boiler No. 4 is an existing source with controlled PM emissions averaging 0.12 lb/MMBtu. This is the starting point for its cost effectiveness calculations, not uncontrolled emissions. As such, annual emissions for cost effectiveness calculations for Boiler No. 7 are much higher than for Boiler No. 4.

Other factors which render the Boiler No. 7 cost effectiveness lower are: 1) Boiler No. 7 is permitted to operate on full load year around (Boiler No. 4 will be limited to an equivalent of 200 days/yr operation); 2) Boiler No. 7 has a higher heat input rate than Boiler No. 4 (812 compared to 633 MMBtu/hr); and 3) because of design and operation with a wet scrubber, Boiler No. 4 has a significantly larger exhaust flow (344,800 compared to 254,587 acfm) that increases the capital cost of an ESP from $2,000,000 to $2,700,000. Both these factors lower the cost efficiency of an ESP making it economically feasible for Boiler No. 7, but not for Boiler No. 4. Boiler No. 7 is certainly not similar to Boiler No. 4, in design or operation and, therefore, separate cost analysis are warranted.

The NPS also had several comments concerning validity of the cost analysis presented to rule out an ESP for Boiler No. 4 based on economic feasibility. These concerns are addressed below:

1. A wet cyclone was included in the cost analysis because the existing impingement scrubber would need to be replaced due to excessive moisture in the flue gas, which would interfere with the operation of an ESP.
2. Working capital costs are less than 1 percent of the total capital investment and, therefore, the costs are not significant.
3. The estimate that an operator will be required for 8 hours per day is based on operational experience for Boiler No. 7; the only known application of an ESP on a bagasse fired boiler. This figure is due to the lack of any previous operating experience with an ESP in the sugar industry. As the OAQPS cost manual is intended as a guide in lieu of situation-specific information, U.S. Sugar's

operational experience is a better indicator of the time and effort required to operate and maintain an ESP on a bagasse fired boiler.

4. The capital cost recovery factor of 7 percent presented in the OAQPS cost manual is used to illustrate example cost calculations. More appropriately, the actual cost of borrowing money should be used, which in this case was assumed to be 10 percent and is representative of current economic conditions.
5. The OAQPS manual indicates a range of useful equipment life for an ESP of 5 to 40 years. Due to the lack of industry data for a ESP on a bagasse fired boiler and the maintenance/replacement costs already incurred for the ESP on Boiler No. 7, a conservative estimate of 10 years was used for the equipment life of the ESP in this cost analysis.
6. The efficiency of the ESP for both cases (Boiler No. 4 and Boiler No. 7) were based on the vendor guarantee of 0.03 lb/MMBtu, although this level of emissions was not achievable on Boiler No. 7 until the wet cyclone was added preceding the ESP. The only difference is that for Boiler No. 4 the current emissions are already down to 0.12 lb/MMBtu, but an ESP would still only achieve a 0.03 lb/MMBtu emission level, since the existing scrubber would be replaced.

Nitrogen Oxides

As stated in the permit application, through good combustion practices, U.S. Sugar achieves an average NO_x emission rate of 0.08 lb/MMBtu. However, U.S. Sugar cannot accept a BACT limit based on average emissions, since this limit will have to be achieved on a continuous basis. Review of the NO_x test data presented in Appendix C of the application shows that stack test results vary from 0.03 to 0.16 lb/MMBtu. Given this variability in NO_x emissions, U.S. Sugar requests an emission limit of 0.25 lb/MMBtu as previously determined as BACT for this unit.

Sulfur Dioxide

Refer to Items 4 and 5 above for a response to this comment.

Thank you for consideration of these responses. Please call or e-mail me if you have any additional questions.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E.
Principal Engineer
Florida P.E. #19011

DB/jkk

Enclosures
cc: **Don Griffin**
Bill Wehrum

\\GATORBAIT\MISCDATA\DATA\DP\Projects\9937515a\01\#01ltr.dot

Table 4-1. Fuel Cost and SO_2 Emission Rate Analysis

Fuel Type/ Sulfur Content	Unit Cost ($/gal)	Usage (gal/yr)		Annual Cost ($/yr)	Cost Increase ($/yr)	SO_2 Emission Rate[a] (TPY)
No. 6 Fuel Oil						
1.5% Sulfur	0.5750	102,350	b	58,851	--	12.6
0.7% Sulfur	0.6179	103,032	c	63,659	4,808	5.7
No. 2 Fuel Oil						
0.5% Sulfur	0.6607	109,661	c	72,454	13,603	3.7
0.05% Sulfur	0.6845	113,722	c	77,846	18,994	0.4

Notes:
1. All prices based on Coastal Fuels Marketing, Inc.'s current prices (FOB)

Footnotes:

[a] Based on the following information:

Fuel Type	Sulfur Content (% by wt.)	Heat Content (Btu/gal)	Density (lb/gal)
No. 2 Fuel Oil	0.5	140,000	6.83
	0.05	135,000	6.83
No. 6 Fuel Oil	1.5	151,000	8.22
	0.7	150,000	7.94

[b] Based on actual average usage of No. 6 fuel oil in 1996, 1997, and 1998 of 96,968, 90,686, and 119,395 gallons, respectively.

[c] Gallons needed for equivalent heat input to No. 6 fuel oil with a sulfur content of 1.5%.

Table 4-2. Cost Effectiveness of No. 6 Fuel Oil (0.7% Sulfur Content With a Common Tank) for Boiler No. 4, U. S. Sugar Clewiston

Cost Items	Cost Factors	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost[a]	Not applicable	0
INDIRECT CAPITAL COSTS (ICC):[b]		
Indirect Installation Costs	Not Applicable	
(a) Engineering	Not Applicable	
(b) Construction & Field Expenses	Not Applicable	
(c) Construction Contractor Fee	Not Applicable	
(d) Contingencies	Not Applicable	
Other Indirect Costs		
(a) Startup & Testing	Not Applicable	
(b) Working Capital	Not Applicable	
Total ICC:		0
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	0
DIRECT OPERATING COSTS (DOC):[c]		
(1) Operating Labor		
Operator		0
Supervisor		0
(2) Maintenance		
Labor	Equivalent to Operating Labor	0
Materials	Equivalent to Maintenance Labor	0
(3) Utilities		
(4) Fuels		
No. 6 Fuel (0.7% Sulfur Content)	See Footnote "d"	4,808
Total DOC:		4,808
INDIRECT OPERATING COSTS (IOC):[c]		
Overhead	60% of oper. labor & maintenance	0
Property Taxes	1% of total capital investment	0
Insurance	1% of total capital investment	0
Administration	2% of total capital investment	0
Total IOC:		0
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.1627 times TCI (10 yrs @ 10%)	0
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	4,808
BASELINE SO_2 EMISSIONS (TPY):	102,350 gallons No. 6 Fuel Oil with a Sulfur of 1.5% by weight	12.6
MAXIMUM SO_2 EMISSIONS WITH NO. 6 FUEL OIL (TPY):	103,032 gallons No. 6 Fuel Oil with a Sulfur Content of 0.7% by weight	5.7
REDUCTION IN SO_2 EMISSONS (TPY):		6.9
COST EFFECTIVENESS:	$ per ton of SO_2 Removed	697

Footnotes:

[a] All direct installation costs are included in basic price.

[b] All indirect installation costs are included in basic price.

[b] Factors and cost estimates reflect OAQPS Cost Manual, Section 3.

[d] Increase in fuel cost associated with buying No. 6 fuel oil with a sulfur content of 0.7% ($0.6179/gal) instead of No. 6 fuel oil with a sulfur content 1.5% ($0.5750/gal) based on purchasing 103,032 gallons per year.

Table 4-3. Cost Effectiveness of No. 6 Fuel Oil (0.7% Sulfur Content With a New Tank) for Boiler No. 4, U. S. Sugar Clewiston

Cost Items	Cost Factors	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost[a]	See Footnote "b"	170,000
INDIRECT CAPITAL COSTS (ICC):[c]		
Indirect Installation Costs		
(a) Engineering	Based on Vendor Quote	Included Above
(b) Construction & Field Expenses	Based on Vendor Quote	Included Above
(c) Construction Contractor Fee	Based on Vendor Quote	Included Above
(d) Contingencies	Based on Vendor Quote	Included Above
Other Indirect Costs		
(a) Startup & Testing	Based on Vendor Quote	Included Above
(b) Working Capital	30-day DOC	Included Above
Total ICC:		Included Above
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	170,000
DIRECT OPERATING COSTS (DOC):[d]		
(1) Operating Labor		
Operator		0
Supervisor		0
(2) Maintenance		
Labor	Equivalent to Operating Labor	0
Materials	Equivalent to Maintenance Labor	0
(3) Utilities		
(4) Fuels		
No. 6 Fuel (0.7% Sulfur Content)	See Footnote "e"	4,808
Total DOC:		4,808
INDIRECT OPERATING COSTS (IOC):[d]		
Overhead	60% of oper. labor & maintenance	0
Property Taxes	1% of total capital investment	1,700
Insurance	1% of total capital investment	1,700
Administration	2% of total capital investment	3,400
Total IOC:		6,800
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.1627 times TCI (10 yrs @ 10%)	27,659
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	39,267
BASELINE SO_2 EMISSIONS (TPY) :	102,350 gallons No. 6 Fuel Oil with a Sulfur of 1.5% by weight	12.6
MAXIMUM SO_2 EMISSIONS WITH NO. 6 FUEL OIL (TPY):	103,032 gallons No. 6 Fuel Oil with a Sulfur Content of 0.7% by weight	5.7
REDUCTION IN SO_2 EMISSONS (TPY):		6.9
COST EFFECTIVENESS:	$ per ton of SO_2 Removed	5,691

Footnotes:

[a] All direct installation costs are included in basic price.

[b] Based on actual installed cost of $170,000 for a similar storage tank installed in 1996..

[c] All indirect installation costs are included in basic price.

[d] Factors and cost estimates reflect OAQPS Cost Manual, Section 3.

[e] Increase in fuel cost associated with buying No. 6 fuel oil with a sulfur content of 0.7% ($0.6179/gal) instead of No. 6 fuel oil with a sulfur content 1.5% ($0.5750/gal) based on purchasing 103,032 gallons per year.

Table 4-4. Cost Effectiveness of No. 2 Fuel Oil (0.5% Sulfur Content With New Tank and Burners) for Boiler No. 4, U. S. Sugar Clewiston

Cost Items	Cost Factors	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost[a]	See Footnote "b"	395,000
INDIRECT CAPITAL COSTS (ICC):[c]		
Indirect Installation Costs		
(a) Engineering	Based on Vendor Quote	Included Above
(b) Construction & Field Expenses	Based on Vendor Quote	Included Above
(c) Construction Contractor Fee	Based on Vendor Quote	Included Above
(d) Contingencies	Based on Vendor Quote	Included Above
Other Indirect Costs		
(a) Startup & Testing	Based on Vendor Quote	Included Above
(b) Working Capital	30-day DOC	Included Above
Total ICC:		Included Above
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	395,000
DIRECT OPERATING COSTS (DOC):[d]		
(1) Operating Labor		
Operator	$17/hr; 200 days/yr @ 8 hrs/day	0
Supervisor	15% of operator cost	0
(2) Maintenance		
Labor	Equivalent to Operating Labor	0
Materials	Equivalent to Maintenance Labor	0
(3) Utilities		
(4) Fuels		
No. 2 Fuel (0.5% Sulfur Content)	See Footnote "e"	13,603
Total DOC:		13,603
INDIRECT OPERATING COSTS (IOC):[d]		
Overhead	60% of oper. labor & maintenance	0
Property Taxes	1% of total capital investment	3,950
Insurance	1% of total capital investment	3,950
Administration	2% of total capital investment	7,900
Total IOC:		15,800
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.1627 times TCI (10 yrs @ 10%)	64,267
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	93,670
BASELINE SO_2 EMISSIONS (TPY) :	102,350 gallons No. 6 Fuel Oil with a Sulfur Content of 1.5% by weight	12.6
MAXIMUM SO_2 EMISSIONS WITH NO. 2 FUEL OIL (TPY):	109,661 gallons No. 2 Fuel Oil with a Sulfur Content of 0.5% by weight	3.7
REDUCTION IN SO_2 EMISSONS (TPY):		8.9
COST EFFECTIVENESS:	$ per ton of SO_2 Removed	10,525

Footnotes:

[a] All direct installation costs are included in basic price.

[b] Based on an actual installed cost of $170,000 for a storage tank and a vendor quote of $225,000 for burner replacement (installed).

[c] All indirect installation costs are included in basic price.

[d] Factors and cost estimates reflect OAQPS Cost Manual, Section 3.

[e] Increase in fuel cost associated with buying No. 2 fuel oil with a sulfur content of 0.5% ($0.6607/gal) instead of No. 6 fuel oil with a sulfur content 1.5% ($0.5750/gal) based on purchasing 109,661 gallons per year.

Table 4-5. Cost Effectiveness of No. 2 Fuel Oil (0.05% Sulfur Content With New Tank and Burners) for Boiler No. 4, U. S. Sugar Clewiston

Cost Items	Cost Factors	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost[a]	See Footnote "b"	395,000
INDIRECT CAPITAL COSTS (ICC):[c]		
Indirect Installation Costs		
(a) Engineering	Based on Vendor Quote	Included Above
(b) Construction & Field Expenses	Based on Vendor Quote	Included Above
(c) Construction Contractor Fee	Based on Vendor Quote	Included Above
(d) Contingencies	Based on Vendor Quote	Included Above
Other Indirect Costs		
(a) Startup & Testing	Based on Vendor Quote	Included Above
(b) Working Capital	30-day DOC	Included Above
Total ICC:		Included Above
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	395,000
DIRECT OPERATING COSTS (DOC):[d]		
(1) Operating Labor		
Operator		0
Supervisor		0
(2) Maintenance		
Labor		0
Materials		0
(3) Utilities		
(4) Fuels		
No. 2 Fuel (0.05% Sulfur Content)	See Footnote "e"	18,994
Total DOC:		18,994
INDIRECT OPERATING COSTS (IOC):[d]		
Overhead	60% of oper. labor & maintenance	0
Property Taxes	1% of total capital investment	3,950
Insurance	1% of total capital investment	3,950
Administration	2% of total capital investment	7,900
Total IOC:		15,800
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.1627 times TCI (10 yrs @ 10%)	64,267
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	99,061
BASELINE SO_2 EMISSIONS (TPY) :	102,350 gallons No. 6 Fuel Oil with a Sulfur Content of 1.5% by weight	12.6
MAXIMUM SO_2 EMISSIONS WITH NO. 2 FUEL OIL (TPY):	113,722 gallons No. 2 Fuel Oil with a Sulfur Content of 0.05% by weight	0.4
REDUCTION IN SO_2 EMISSONS (TPY):		12.2
COST EFFECTIVENESS:	$ per ton of SO_2 Removed	8,120

Footnotes:

[a] All direct installation costs are included in basic price.

[b] Based on an actual installed cost of $170,000 for a storage tank and a vendor quote of $225,000 for burner replacement (installed).

[c] All indirect installation costs are included in basic price.

[d] Factors and cost estimates reflect OAQPS Cost Manual, Section 3.

[e] Increase in fuel cost associated with buying No. 2 fuel oil with a sulfur content of 0.05% ($0.6845/gal) instead of No. 6 fuel oil with a sulfur content 1.5% ($0.5750/gal) based on purchasing 113,723 gallons per year.

Table 4-6 Summary of the Cost Effectiveness of SO_2 Control Options

Description of Control Option	Annualized Cost ($/yr)	Maximum SO_2 Emission Rate (TPY)	Reduction in SO_2 Emission Rate[a] (TPY)	Cost Effectiveness ($/ton removed)
Replace No. 6 Fuel Oil (1.5% S) with No. 6 Fuel Oil (0.7% S) Stored in the Common Storage Tank	4,808	5.7	6.9	697
Replace No. 6 Fuel Oil (1.5% S) with No. 6 Fuel Oil (0.7% S) Stored in a New Storage Tank	39,267	5.7	6.9	5,691
Replace No. 6 Fuel Oil (1.5% S) with No. 2 Fuel Oil (0.5% S) Stored in a New Storage Tank and Replacement of Burners to Accommodate the New Fuel	93,670	3.7	8.9	10,525
Replace No. 6 Fuel Oil (1.5% S) with No. 2 Fuel Oil (0.05% S) Stored in a New Storage Tank and Replacement of Burners to Accommodate the New Fuel	99,061	0.4	12.2	8,120

Footnote:
[a] Based on a baseline SO_2 emission rate of 12.6 TPY.

Table 2-1. Short Term Emissions of Regulated Pollutants for Boiler No. 4 (revised 8/23/99)

Regulated Pollutant	Emission Factor (lb/MMBtu)	Ref	Activity Factor 1-Hour Max. (MMBtu/hr)(a)	Activity Factor 24-Hour Avg. (MMBtu/hr)(a)	Maximum Hourly Emissions (lb/hr)	Maximum 24-Hour Emissions (lb/hr)
			Carbonaceuos Fuel			
Particulate Matter (PM)	0.15	1	633	600	95.0	90.0
Particulate Matter (PM10)	0.14	2	633	600	88.3	83.7
Sulfur dioxide	0.1	3	633	600	63.3	60.0
Nitrogen oxides	0.25	4	633	600	158.3	150.0
Carbon monoxide	6.5	1	633	600	4,114.5	3,900.0
VOC	0.5	5	633	600	316.5	300.0
Sulfuric Acid Mist	0.006	6	633	600	3.9	3.7
Lead	4.45E-04	7	633	600	0.28	0.27
Mercury	3.8E-05	8	633	600	0.0241	0.0228
Beryllium	--	7	633	600	--	--
			No. 6 Fuel Oil			
Particulate Matter (PM)	0.10	1	225	--	22.5	22.5
Particulate Matter (PM10)	0.10	9	225	--	22.5	22.5
Sulfur dioxide (b)	2.73	10	225	--	615.0	615.0
Nitrogen oxides	0.31	11	225	--	69.8	69.8
Carbon monoxide	0.033	11	225	--	7.5	7.5
VOC	0.0019	11	225	--	0.4	0.4
Sulfuric Acid Mist	0.044	6	225	--	9.9	9.9
Lead	1.01E-05	11	225	--	2.27E-03	2.27E-03
Mercury	7.53E-07	11	225	--	1.70E-04	1.70E-04
Beryllium	1.85E-07	11	225	--	4.17E-05	4.17E-05
			Maximum No. 6 Fuel Oil/ Remainder Bagasse			
Particulate Matter (PM)			530	499	68.3	63.6
Particulate Matter (PM10)			530	499	65.1	60.7
Sulfur dioxide			530	499	645.6	642.4
Nitrogen oxides			530	499	146.2	138.2
Carbon monoxide			530	499	1,993.3	1,787.2
VOC			530	499	153.2	137.3
Sulfuric Acid Mist			530	499	11.8	11.6
Lead			530	499	0.14	0.12
Mercury			530	499	0.012	0.011
Beryllium			530	499	4.17E-05	4.17E-05
			Maximum Any Combination			
Particulate Matter (PM)					95.0	90.0
Particulate Matter (PM10)					88.3	83.7
Sulfur dioxide					645.6	642.4
Nitrogen oxides					158.3	150.0
Carbon monoxide					4,114.5	3,900.0
VOC					316.5	300.0
Sulfuric Acid Mist					11.8	11.6
Lead					0.28	0.27
Mercury					0.0241	0.0228
Beryllium					4.17E-05	4.17E-05

Footnotes

(a) Maximum 1-hour activity factor is based on a steam production of 300,000 lb/hr at 600 psig, 750 F.
Maximum 6-hour average activity factor based on steam production rate of 285,000 lb/hr at 600 psig, 750 F.
Enthalpy of steam = 1,378 Btu/lb. Enthalpy of feedwater = 218 Btu/lb. Net enthalpy = 1,160 Btu/lb.
Boiler efficiency = 80% on fuel oil and 55% on bagasse.
Derivation of heat input for No. 6 Fuel oil/Bagasse combination firing:
Max 1-hr case: Max oil = 225 MMBtu/hr x 80% eff. = 180 MMBtu/hr into steam.
Remainder needed into steam = (300,000 lb/hr steam x 1,160 Btu/lb) - 180 MMBtu/hr = 168 MMBtu/hr
Required heat input to boiler from bagasse = 168 MMBtu/hr / 55% eff. = 305.5 MMBtu/hr
Total heat input required = 225 + 305.5 = 530 MMBtu/hr
Max 24-hr case: Max oil = 225 MMBtu/hr x 80% eff. = 180 MMBtu/hr into steam.
Remainder needed into steam = (285,000 lb/hr steam x 1,160 Btu/lb) - 180 MMBtu/hr = 150.6 MMBtu/hr
Required heat input to boiler from bagasse = 150.6 MMBtu/hr / 55% eff. = 273.8 MMBtu/hr
Total heat input required = 225 + 274 = 499 MMBtu/hr

(b) The SO2 emission factor reflects the maximum sulfur content (2.5%) which could exist in the common plant No. 6 fuel oil tank. Boiler Nos. 1, 2 and 3 are permitted to burn up to 2.5% sulfur fuel oil, while the amount of fuel oil burned in Boiler No. 4 during a crop season will be replaced in the plant common fuel oil tank with fuel oil containing no more than 0.7% sulfur.

References

1. Current BACT permit limit for Clewiston.
2. Based on limited source testing of bagasse boiler which indicated 93% of PM was PM10.
3. Proposed BACT limit, based on actual stack testing on Clewiston boilers. Equivalent to 0.1% sulfur content of bagasse (wet), 3,600 Btu/lb(wet); and 82% removal in wet scrubber.
4. Equivalent to current permit limit for Clewiston Boiler No. 4.
5. Proposed permit limit.
6. Based on assuming 5% of SO2 emissions are equal to SO3, based on AP-42 Section 1.3, Fuel Oil Combustion. Conversion of SO3 to H2SO4 (SO3 x 98/80).
7. Based on AP-42, Section 1.6, Wood Waste Combustion. Represents controlled emissions.
8. Based on stack testing of 5 bagasse boilers in Florida (refer to appendices).
9. Assumed as 100% of PM emissions.
10. Based on 2.5% S fuel oil; 150,000 Btu/gal; 8.2 lb/gal; assumes 100% conversion of sulfur to SO2.
11. Based on AP-42, Section 1.3, Fuel Oil Combustion.
NOx - 47 lb/1000 gal; CO - 5 lb/1000 gal; VOC - 0.28 lb/1000 gal;
Lead - 1.51E-03 lb/1000 gal; Mercury - 1.13E-04 lb/1000 gal; Beryllium - 2.85E-05 lb/1000 gal

Example Calculations

Single Fuel Combustion:
Hourly Emission Rate = Emission Factor X Activity Factor (1-hour maximum)

Multiple Fuel Combustion:
= {(Bagasse Activity Factor - Fuel Oil Activity Factor) x Bagasse Emission Factor}
+ (Fuel Oil Activity Factor x Fuel Oil Emission Factor)

Table 2-2. Future Maximum Annual Emissions, Clewiston Boiler No. 4, U.S. Sugar Corp. (revised 8/20/99)

Pollutant	Bagasse Firing				Fuel Oil Firing				TOTAL EMISSIONS (TPY)
	Emission Factor		Heat Input (a) (MMBtu/yr)	Emissions (TPY)	Emission Factor		Heat Input (a) (MMBtu/yr)	Emissions (TPY)	
Particulate Matter (PM)	0.15	lb/MMBtu	2,880,000	216.0	0.1	lb/MMBtu	0	0.0	216.0
PM10	0.14	lb/MMBtu	2,880,000	201.6	0.1	lb/MMBtu	0	0.0	201.6
Sulfur Dioxide	0.1	lb/MMBtu	2,805,000	140.3	0.74	lb/MMBtu (b)	75,000	27.8	168.0
Nitrogen Oxides	0.25	lb/MMBtu	2,805,000	350.6	0.31	lb/MMBtu	75,000	11.6	362.3
Carbon Monoxide	6.5	lb/MMBtu	2,880,000	9,360.0	0.033	lb/MMBtu	0	0.0	9,360.0
Volatile Organic Compounds	0.5	lb/MMBtu	2,880,000	720.0	0.0019	lb/MMBtu	0	0.0	720.0
Sulfuric Acid Mist	0.006	lb/MMBtu	2,880,000	8.8	0.045	lb/MMBtu	0	0.0	8.8
Lead	4.45E-04	lb/MMBtu	2,880,000	0.6	1.01E-05	lb/MMBtu	0	0.0	0.64
Mercury	3.80E-05	lb/MMBtu	2,880,000	0.1	7.53E-07	lb/MMBtu	0	0.0	0.055
Beryllium	--		2,805,000	--	1.85E-07	lb/MMBtu	75,000	6.94E-06	6.94E-06

(a) Total heat input based on total steam production of 1.368E+09 lb steam/yr, 1,160 Btu/lb steam and 55% thermal efficiency.
Fuel oil considered where worst case emission factor is due to oil burning. Maximum fuel oil burning is 500,000 gal/yr, equivalent to 75,000 MMBtu/yr.
(b) Represents maximum sulfur content of 0.7% for fuel oil to be replaced in the plant common fuel oil tank.

References: Refer to Table 2-1 for emission factors.

Table 3-3. Baseline Emissions for Clewiston Boiler No. 4, U.S. Sugar Corp. (revised 8/20/99)

Pollutant	Bagasse Firing					Fuel Oil Firing					TOTAL
	Emission Factor		Ref.	Heat Input (a) (MMBtu/yr)	Emissions (TPY)	Emission Factor		Ref.	Heat Input (b) (MMBtu/yr)	Emissions (TPY)	EMISSIONS (TPY)
Particulate Matter (PM)	0.12	lb/MMBtu	1	1,661,913	99.7	0.1	lb/MMBtu	4	15,816	0.79	100.5
PM10	0.112	lb/MMBtu	2	1,661,913	93.1	0.1	lb/MMBtu	9	15,816	0.79	93.9
Sulfur Dioxide	0.008	lb/MMBtu	1	1,661,913	6.6	1.67	lb/MMBtu	5	15,816	13.21	19.9
Nitrogen Oxides	0.082	lb/MMBtu	1	1,661,913	68.1	0.31	lb/MMBtu	10	15,816	2.45	70.6
Carbon Monoxide	6.36	lb/MMBtu	1	1,661,913	5,284.9	0.033	lb/MMBtu	10	15,816	0.26	5,285.1
Volatile Organic Compounds	0.25	lb/MMBtu	3	1,661,913	207.7	0.0019	lb/MMBtu	10	15,816	0.015	207.8
Sulfuric Acid Mist	0.00049	lb/MMBtu	6	1,661,913	0.4	0.10	lb/MMBtu	6	15,816	0.81	1.2
Lead	4.45E-04	lb/MMBtu	7	1,661,913	0.37	1.01E-05	lb/MMBtu	10	15,816	7.99E-05	0.37
Mercury	8.00E-06	lb/MMBtu	8	1,661,913	6.65E-03	7.53E-07	lb/MMBtu	10	15,816	5.95E-06	6.65E-03
Beryllium	--		7	1,661,913	0.0	1.85E-07	lb/MMBtu	10	15,816	1.46E-06	1.46E-06

(a) Based on actual steam production during 1997 and 1998, and actual steam enthalpies during stack tests.
(b) Based on average fuel oil usage during last two crop seasons of 90,686 gal (1997) and 119,395 gal (1998) and 151,000 Btu/gal

Footnotes:
(1) Based on average of stack tests from last 5 years.
(2) Based on 93% of PM emissions for bagasse burning based on limited testing of a bagasse boiler.
(3) Test data not available; assumed equal to permit limit of 1.7 lb/ton wet bagasse.
(4) Based on permit limit.
(5) Based on stoichiometric calculation of sulfur content (1.5 %) and density of No. 6 fuel oil (8.22 lb/gal).
(6) Based on assuming 5% of SO2 emissions are equal to SO3, based on AP-42 Section 1.3, Fuel Oil Combustion.
Conversion of SO3 to H2SO4 (SO3 x 98/80).
(7) Based on AP-42, Section 1.6, Wood Waste Combustion. Represents controlled emissions.
(8) Based on average emission factor from stack testing of 5 bagasse boilers in Florida (refer to appendices).
(9) Assumed as 100% of PM emissions.
(10) Based on AP-42, Section 1.3, Fuel Oil Combustion.
NOx - 47 lb/1000 gal; CO - 5 lb/1000 gal; VOC - 0.28 lb/1000 gal;
Lead - 1.51E-03 lb/1000 gal; Mercury - 1.13E-04 lb/1000 gal; Beryllium - 2.85E-05 lb/1000 gal

Table 3-4. Net Emissions Increase for Clewiston Boiler No. 4, U.S. Sugar Corp. (revised 8/20/99)

Pollutant	PSD Baseline Emissions (TPY)	Future Maximum Emissions (TPY)	Net Increase in Emissions (TPY)	PSD Significant Emission Rate (TPY)	PSD Review Applies?
Particulate Matter (PM)	100.5	216.0	115.5	25	Yes
PM10	93.9	201.6	107.7	15	Yes
Sulfur Dioxide	19.9	168.0	148.1	40	Yes
Nitrogen Oxides	70.6	362.3	291.7	40	Yes
Carbon Monoxide	5,285.1	9,360.0	4,074.9	100	Yes
Volatile Organic Compound	207.8	720.0	512.2	40	Yes
Sulfuric Acid Mist	1.2	8.8	7.6	7	Yes
Lead	0.37	0.64	0.27	0.6	No
Mercury	0.007	0.055	0.048	0.1	No
Beryllium	1.46E-06	6.94E-06	5.47E-06	4.00E-04	No

Table 1-1. Estimated Emissions for the Proposed Project (revised August 20, 1999)

Pollutant	Boiler No. 4 Baseline Emissions (TPY)	Boiler No. 4 Future Maximum Emissions (TPY)	Sugar Refinery Future Maximum Emissions (TPY)	Net Increase in Emissions (TPY)	PDS Significant Emission Rate (TPY)
PM	100.5	216.0	24.0	139.5	25
PM_{10}	93.9	201.6	24.0	131.7	15
SO_2	19.9	168.0	30.7	178.8	40
NO_x	70.6	362.3	8.8	300.5	40
CO	5285.1	9,360.0	7.8	4,082.7	100
VOC	207.8	720.0	20.1	532.3	40
Sulfuric Acid Mist	1.2	8.8	0	7.6	7
Lead	0.37	0.64	0	0.27	0.6
Mercury	0.007	0.055	0	0.048	0.1
Beryllium	0.0000015	0.0000069	0	0.0000055	0.0004

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): External combustion boilers; Industrial; Residual oil; Grade 6 oil	
2. Source Classification Code (SCC): 1-02-004-01	
3. SCC Units: Thousand Gallons Burned	
4. Maximum Hourly Rate: 1.5	5. Maximum Annual Rate: 500
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: 0.7	8. Maximum Percent Ash:
9. Million Btu per SCC Unit: 150	
10. Segment Comment (limit to 200 characters): Max hourly and annual rates based on permit specific conditions.	

Emissions Unit Information Section 1 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: **OTHER**	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: **2.5 % Sulfur Oil**	
4. Equivalent Allowable Emissions: **645.6** lb/hour	**168.0** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 6 or 6C**	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Applies to total combined carbonaceous fuel and fuel oil firing.**	

B.

1. Basis for Allowable Emissions Code: **OTHER**	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: **0.1 lb/MMBtu**	
4. Equivalent Allowable Emissions: **63.3** lb/hour	**140.3** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 6 or 6C**	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Applies to carbonaceous fuel firing only.**	

Emissions Unit Information Section 1 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 2.5 %S fuel oil
4. Equivalent Allowable Emissions: 615 lb/hour 27.8 tons/year
5. Method of Compliance (limit to 60 characters): Fuel Analysis
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on max heat input of 225 MMBtu/hr from fuel oil firing and assumes no removal in wet scrubber. Annual emission based on 500,000 gal/yr.

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: VOC
2. Total Percent Efficiency of Control: %
3. Potential Emissions: 316.5 lb/hour 720.0 tons/year
4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr
6. Emission Factor: 0.5 lb/MMBtu Reference: Proposed Limit
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5
8. Calculation of Emissions (limit to 600 characters): See Tables 2-1 and 2-2
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): Max emissions representative of carbonaceous fuel firing. Annual emissions based on heat input rate of 2,880,000 MMBtu/yr.

Emissions Unit Information Section 1 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.5 lb/MMBtu
4. Equivalent Allowable Emissions: 316.5 lb/hour 720.0 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 9
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):