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Golder Associates

October 17, 2005

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Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RECEIVED
OCT 18 2005
BUREAU OF AIR REGULATION

Attention: Mr. Jeff Koerner, P.E., Air Permitting South

RE: UNITED STATES SUGAR CORPORATION
CLEWISTON AND BRYANT MILLS
TITLE V RENEWAL APPLICATION
REQUEST FOR ADDITIONAL INFORMATION

Dear Mr. Jeff Koerner:

United States Sugar Corporation (U.S. Sugar) has received the Department's request for additional information (RAI) dated July 19, 2005, regarding the Title V renewal application. Each of the Department's requests is answered below, in the same order as they appear in the RAI letter.

Comment 1. Please provide support for U.S. Sugar's contention that the maximum true vapor pressure of the fuel oil storage tanks is less than 3.5 kilopascals, rendering inapplicable to 40 CFR 60, Subpart Kb. Also, it is noted that existing PSD permit revisions are not prompted as a result of changes within affected NSPS Standards, whether such standards are becoming more (or less) stringent.

Response: AP-42 Section 7, Table 7.1-2 (2/96), presents true vapor pressure values in pounds per square inch (psi) for both No. 2 fuel oil and No. 6 fuel oil for a range of temperatures. In order to convert to kilopascals (kPa), these values were multiplied by a factor of 6.895. For the 40°F to 100°F temperature range, the No. 2 fuel oil vapor pressures ranged from 0.021 kPa to 0.152 kPa. The No. 6 fuel oil vapor pressures ranged from 0.00014 kPa to 0.0013 kPa for the same temperatures. This demonstrates that the vapor pressures for both No. 2 fuel oil and No. 6 fuel oil are much less than 3.5 kPa, which renders Subpart Kb inapplicable to the fuel storage tanks. A table providing the AP-42 vapor pressure values is included below:

	No. 2 Fuel Oil		No. 6 Fuel Oil	
	True Vapor Pressure, P_{VA} (psi)	True Vapor Pressure, P_{VA} (kPa)	True Vapor Pressure, P_{VA} (psi)	True Vapor Pressure, P_{VA} (kPa)
40°F	0.0031	0.021	0.00002	0.00014
50°F	0.0045	0.031	0.00003	0.00021
60°F	0.0074	0.051	0.00004	0.00028
70°F	0.0090	0.062	0.00006	0.00041
80°F	0.012	0.083	0.00009	0.00062
90°F	0.016	0.11	0.00013	0.0009
100°F	0.022	0.15	0.00019	0.0013

In addition, we are requesting through the concurrent AC/Title V application that the PSD permit be modified to remove the tanks as regulated units. With the non-applicability of Subpart Kb, there is no reason or regulatory basis to regulate fuel oil storage tanks. The VOC emissions from such tanks are negligible.

Comment 2. **The application requests removal of the condition within PSD-FL-333A, which requires (in part) VE compliance testing on the "B" Tandem conveyor transfer point from the C4 conveyor as well as the C1 to C2 conveyor transfer point. The application indicates that since these baghouses were located (and discharged) within the partially enclosed Boiler building, VE tests have become infeasible. Please provide suggestions for possible alternatives to the elimination of emissions testing; include any feasible hardware options, as well as potential process measurements for surrogates to VE testing.**

Response: Two of the five permitted dust collectors have been installed as specified in Permit No. 0510003-024-AC/PSD-FL-333A. One is a dust collector that controls fugitive dust emissions where bagasse is transferred onto the C7 conveyor, and the second is a dust collector that controls fugitive dust emissions from the C1 to C2 bagasse conveyor transfer point. The required VE testing was successfully conducted on the C7 conveyor transfer point; however, a valid VE reading was not feasible from the C1 to C2 conveyor transfer point dust collector due to its location inside the partially enclosed Boiler Building.

The request to eliminate visible emissions (VE) testing from the construction permit applies only to the dust collector that controls fugitive emissions from the C1 to C2 conveyor transfer point. One possible alternative in lieu of eliminating the emissions test is to develop an Operation and Maintenance (O&M) Plan for the dust collector. In addition, the pressure drop across the unit may be monitored as a way of determining correct operation of the dust collector. Note that this dust collector is not required by any air control regulations and was installed voluntarily by U.S. Sugar as a means of reducing potential fugitive dust emissions. As such, we believe an O&M Plan should satisfy the Department's concerns.

Comment 3. **U.S. Sugar requests that annual compliance testing for NOx and VOC for Boiler No. 4, and annual VOC testing for Boiler No. 7 be reduced from annually to once every five years, or upon renewal of the Title V application. The rational cited by the applicant is that the "emissions have historically tested well below the permit limits."**

A) Please provide additional detail for the historical compliance test results. In particular the Department is interested in reviewing each of the individual test runs, which comprised several years' worth of lb/MMBtu emission results summarized within Tables 1 and 2 of the application.

Response: Table 1 presents individual test runs of emission results from 1999 to 2004 for Boilers No. 4 and 7. This data was used in Tables 1 and 2 of the renewal application to support a reduced NOx and VOC testing frequency for Boiler No. 4 and a reduced VOC testing frequency for Boiler No. 7. We believe that all the data is representative of current operations.

B) Please submit a chronological summary of all changes which have occurred to Boiler Nos. 4 and 7 since year 1998, whether such changes were physical in nature, or changes to the method of operation.

Response: U.S. Sugar was issued Air Construction Permit No. 0510003-22-AC on June 3, 2003. This permit authorized a 3-year boiler maintenance project at the existing Clewiston Mill that expires on October 1, 2005. U.S. Sugar conducted repairs to the boilers during the 2003 through 2005 off-seasons; however, because all the repairs were not completed during the specified time, U.S. Sugar has applied for an extension to the air permit. Below is a list of all routine repair and maintenance activities that have been completed on Boiler Nos. 4 and 7 since the 2001 off-season. These activities have been reported previously to the Department to satisfy the permit conditions. There are no maintenance records prior to 2001.

2001 Off-Season

- Boiler No. 4
    - Replaced all roof tubes and side header feed tubes
    - Replaced about 60% of generating bank tubes
    - Repaired roof refractory
    - Repaired generating bank wall
    - Air and gas ducting general repairs
    - Replaced outer skin and inner skirt of scrubber
- Boiler No. 7
    - New bagasse feeders and repair of chutes
    - Replaced a section of screenwall tubes in the gas path
    - Replaced remaining superheater tubes
    - Rebuilt the ID fan
    - Replaced last two-thirds of economizer
    - Installed soot blowers

2002 Off-Season

- Boiler No. 4
    - Replaced 25 percent of chains and slats on the stoker
    - Replaced both sidewall tubes during refractory repair
    - Replaced remaining 40% of tubes
    - Replaced tile in both refractory sidewalls
    - Replaced tile baffles and rear wall, repaired buckstays
    - Replaced top half of air heater tubes
    - Replaced outer skin and inner skirt of scrubber
    - General insulation repairs
- Boiler No. 7
    - Replaced bent superheater header
    - Replaced refractory in east, west and front wall, and roof
    - Replaced refractory in rear wall and replace approximately 80 bent furnace tubes
    - Replaced skin on penthouse, replaced insulation in penthouse, replaced all bent hangers and added one row of additional hangers in penthouse
    - Purchased and installed new Gyrol for ID fan drive
    - Replaced last two-thirds of economizer
    - General insulation repairs

2003 Off-Season

- Boiler No. 4
    - Replaced about 40% of generating bank
    - Replaced sidewall furnace tubes
    - Replaced sidewall refractory and insulations

- Routine stoker repairs
- Installed undergrate sand removal system
- Replaced ash removal screw conveyor with submerged ash conveyor
- Replaced upper half of air heater tubes
- Routine ID fan repair
- General erosion repairs on scrubber
- Replaced bearings on all fans
- Routine valve repair

- Boiler No. 7
  - Replaced 80 sidewall and front wall tubes
  - Replaced refractory in all four furnace walls and roof
  - Replaced two-thirds of economizer tubes
  - Routine stoker repair including replacement of drives with new
  - Routine ID fan repair including replacement of rotor
  - Routine erosion repairs on scrubber
  - Replaced bearings on all fans
  - Routine valve repair
  - Routine erosion repairs to cyclone separator
  - Routine inspection and repair of ESP

2004 Off-Season
- Boiler No. 4
  - Replaced the lower rear wall header
  - Replaced the superheater tubes
  - Replaced the front and rear wall tubes
- Boiler No. 7
  - Replaced the economizer tubes
  - Installed new electrodes in all three fields of the ESP
  - Installed new ID fan and reworked the inlet to the ID fan to improve flue gas flow losses

2005 Off-Season
- Boiler No. 4
  - Replacement of approximately 16 riser tubes and repair of inner tile baffle
  - General refractory repairs
  - General flue and duct repairs
- Boiler No. 7
  - Replacement of wet sand separator
  - Replacement of 2nd and 3rd field collector plates in ESP
  - Modification of ESP hopper to convert one screw conveyor into two
  - Replacement of submerged ash conveyor
  - General refractory repairs
  - Replacement of undergrate air ducting
  - Compartmentalization of undergrate air supply into three zones
  - Replacement of economizer feed and discharge headers

In addition to routine repair and maintenance on Boiler Nos. 4 and 7 (as listed above), the changes that have occurred to Boiler Nos. 4 and 7 since 1998 are listed below:

- Replacement of auxiliary fan on Boiler No. 4 (2003)
- Installed new fuel oil burners on Boiler No. 7 (2003)
- Replacement of stack on Boiler No. 7 (2004)
- Installed new fuel oil system on Boiler No. 4 (2005)
- Changed undergrate dampers on Boiler No. 7 (2005)
- Automation of control system on Boiler No. 7 (2005)
- Replacement of ID fan rotor on Boiler No. 7 (2005)
- Replacement of single wet sand separator on Boiler No. 7 with two new wet sand separators (2005)

Comment 4. **The Department is not inclined to authorize excess emissions during periods of startup and shutdown for longer than 2 hours (and up to 12 hours), based upon the time frames required to start the units up as outlined within U.S. Sugar's procedures.**

Response: The startup and shutdown procedures for each boiler outlined in U.S. Sugar's Title V renewal application state that a hot startup will take approximately 1 to 5 hours and a cold startup will take approximately 6 to 12 hours. These startup periods are necessary for safety reasons and to insure the boilers are not damaged during startup. Based on the potential for excess emissions during startup and shutdown, U.S. Sugar is requesting that the Department authorize excess emissions up to 12 hours and explicitly state this in the permit. The current permit only authorizes 2 hours of excess emissions.

Comment 5. **The application states that the fuel oil nitrogen content limit for Boiler 7 is not considered necessary, and that a compliance determination method is not stated. However, according to Air Construction Permit No. 0510003-018-AC, Condition B.2. "The nitrogen content of the distillate oil shall not exceed 0.015% nitrogen by weight as determined by ASTM Method D4629 or equivalent methods approved by the Department." Please provide further justification for the elimination of the fuel oil nitrogen content requirement and identify alternatives which the applicant deems acceptable.**

Response: The original fuel oil nitrogen content limitation is specified in Permit No. AC26-238006/PSD-FL-208. Boiler No. 7 was able to meet the NO_x emissions limit during the initial NO_x compliance test while firing 100-percent No. 2 fuel oil (< 0.05 percent sulfur), and this test showed that NO_x emissions were 20% less than the permitted limit. The nitrogen content of 0.05% sulfur No. 2 fuel oil, which is on-road diesel fuel, is not expected to vary significantly, since it must meet minimum EPA requirements.

In addition, 40 CFR 60, Subpart Db does not specifically state any fuel oil nitrogen content limitations for boilers firing distillate oil only. Moreover, the nitrogen content of fuel oil is not a standard specification provided by fuel oil suppliers. They claim they cannot provide such an analysis. Thus, to affirmatively demonstrate compliance with the condition, U.S. Sugar would have to conduct its own sampling and analysis for every delivery.
Therefore, we believe that the fuel oil nitrogen content limit is not necessary. Additionally, U.S. Sugar is not aware of any other boiler in Florida being required to meet such a nitrogen content limitation. The Department should provide justification as to why this condition should continue in the Title V permit.

Comment 6. No CAM Plan was included with the Title V application rendering the Title V application incomplete.

Response: The CAM Plan was sent to FDEP on September 22, 2005.

Comment 7. We are still awaiting comments from the EPA and the National Park Service on the requested PSD revisions. We will forward them to you when received and they will comprise part of this completeness review.

Response: Since we have not received any comments from the EPA and the National Park Service on the requested PSD revisions, our assumption is that there are not comments.

Thank you for consideration of this information. If you have any questions, please do not hesitate to call me at (352)336-5600.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E., Q.E.P.
Principal Engineer

DB/all

cc: Don Griffin
Peter Briggs
Jose Garcia, Palm Beach County Health Unit
Ron Blackburn, FDEP Fort Meyers

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Table 1. Individual Runs - Emission Tests Performed on Bagasse Boiler Nos. 4 and 7 - U.S. Sugar Corporation - Clewiston

Unit	Boiler Type	Test Date	Stack Gas Flow Rate (dscfm)	Stack Gas Flow Rate (acfm)	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate [1] (TPH)	NOx Emissions (EPA Method 7e)		VOC Emissions as Reported (EPA Method 18/25A)			VOC Emissions as Carbon (EPA Method 18/25A) [3]		Oxygen (%, dry)	Excess Air (%)
								lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	Basis	lb/hr	lb/MMBtu		
Boiler 4	Traveling Grate	01/05/00	136,759	210,179	238,378	509.00	70.69	45.10	0.089	143.65	0.282	As Carbon	143.65	0.282	10.0	91
Boiler 4	Traveling Grate	01/05/00	136,322	209,218	241,644	514.50	71.46	34.83	0.068	489.57	0.952	As Carbon	489.57	0.952	9.0	75
Boiler 4	Traveling Grate	01/05/00	135,432	208,934	236,800	504.80	70.11	32.79	0.065	374.62	0.742	As Carbon	374.62	0.742	9.3	79
Boiler 4	Traveling Grate	11/17/00	161,372	248,028	258,400	558.20	77.53	52.07	0.093	185.93	0.333	As Propane	151.94	0.272	9.5	82
Boiler 4	Traveling Grate	11/17/00	160,074	248,560	256,667	554.70	77.04	58.93	0.106	121.22	0.219	As Propane	99.06	0.179	9.7	85
Boiler 4	Traveling Grate	11/17/00	161,936	249,043	262,192	566.90	78.74	68.05	0.120	214.45	0.378	As Propane	175.25	0.309	9.7	85
Boiler 4	Traveling Grate	01/23/02	158,108	238,305	255,882	549.83	76.37	69.24	0.126	15.24	0.028	As Propane	12.45	0.023	11.1	112
Boiler 4	Traveling Grate	01/23/02	151,705	231,241	257,647	555.59	77.17	67.24	0.121	14.01	0.025	As Propane	11.45	0.020	10.7	104
Boiler 4	Traveling Grate	01/23/02	155,993	236,906	260,294	561.30	77.96	61.04	0.109	19.68	0.035	As Propane	16.08	0.029	10.8	107
Boiler 4	Traveling Grate	12/18/02	167,367	250,551	272,000	600.42	83.39	61.05	0.102	106.09	0.177	As Carbon	106.09	0.177	10.6	98
Boiler 4	Traveling Grate	12/18/02	164,949	247,408	272,000	599.88	83.32	49.79	0.083	130.41	0.217	As Carbon	130.41	0.217	10.1	89
Boiler 4	Traveling Grate	12/18/02	161,294	241,460	274,783	601.71	83.57	52.95	0.088	75.53	0.126	As Carbon	75.53	0.126	10.1	90
Boiler 4	Traveling Grate	12/19/02	163,340	245,494	284,250	627.36	87.13	62.93	0.100	30.90	0.049	As Carbon	30.90	0.049	10.4	95
Boiler 4	Traveling Grate	11/21/03	184,631	280,071	265,479	579.88	80.54	83.16	0.143	306.20	0.528	As Propane	250.22	0.431	9.6	86
Boiler 4	Traveling Grate	11/21/03	187,732	272,428	264,167	576.87	80.12	65.30	0.113	256.84	0.445	As Propane	209.89	0.364	9.4	84
Boiler 4	Traveling Grate	11/21/03	179,768	261,129	260,000	567.11	78.77	84.92	0.150	201.86	0.356	As Propane	164.96	0.291	10.3	99
Boiler 4	Traveling Grate	11/24/04	164,581	254,686	267,115	588.49	81.73	37.81	0.064	186.89	0.318	As Propane	152.73	0.260	9.7	86
Boiler 4	Traveling Grate	11/24/04	165,619	262,011	259,737	572.19	79.47	70.99	0.124	334.55	0.585	As Propane	273.39	0.478	9.4	82
Boiler 4	Traveling Grate	11/24/04	166,378	265,717	254,526	558.23	77.53	63.94	0.115	0.00	0.000	As Propane	0.00	0.000	10.03	92
	Number of Runs		19		19	19	19	19	19	19	19		16	16	19	19
	MEAN		**161,229**		**260,103**	**565.6**	**78.56**	**59.06**	**0.104**	**168.82**	**0.305**		**152.63**	**0.279**	**9.98**	**91**
	MINIMUM		135,432		236,800	504.8	70.11	32.79	0.064	0.00	0.000		11.45	0.020	9.01	75
	MAXIMUM		187,732		284,250	627.4	87.13	84.92	0.150	489.57	0.952		489.57	0.952	11.10	112
	STD DEVIATION		14,378		12,033	32.1	4.45	14.58	0.024	136.92	0.260		131.88	0.257	0.57	10
	95% CL OF RUNS		**189,986**		**284,169**	**629.8**	**87.47**	**88.21**	**0.153**	**442.66**	**0.825**		**416.38**	**0.794**	**11.11**	**110**
	GEOMETRIC MEAN		**160,610**		**259,837**	**564.8**	**78.44**	**57.19**	**0.101**	**117.10**	**0.207**		**95.08**	**0.169**	**9.96**	**90**

Table 1. Individual Runs - Emission Tests Performed on Bagasse Boiler Nos. 4 and 7 - U.S. Sugar Corporation - Clewiston

Unit	Boiler Type	Test Date	Stack Gas Flow Rate (dscfm)	Stack Gas Flow Rate (acfm)	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate [1] (TPH)	NOx Emissions (EPA Method 7e)		VOC Emissions as Reported (EPA Method 18/25A)			VOC Emissions as Carbon (EPA Method 18/25A) [3]		Oxygen (%, dry)	Excess Air (%)
								lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	Basis	lb/hr	lb/MMBtu		
Boiler 7	Vibrating Grate	12/17/99	134,535	281,611	369,429	763.08	105.98	133.53	0.175	21.24	0.028	As Carbon	21.24	0.028	3.60	21
Boiler 7	Vibrating Grate	12/17/99	134,831	283,198	357,429	736.74	102.33	159.54	0.217	2.65	0.004	As Carbon	2.65	0.004	4.80	30
Boiler 7	Vibrating Grate	12/17/99	136,090	279,965	366,176	755.14	104.88	132.65	0.176	4.47	0.006	As Carbon	4.47	0.006	4.90	30
Boiler 7	Vibrating Grate	01/05/01	179,424	335,178	327,500	655.88	91.09	147.31	0.225	0.70	0.001	As Carbon	0.70	0.001	9.08	75
Boiler 7	Vibrating Grate	01/05/01	174,762	329,742	326,667	667.68	92.73	144.48	0.216	0.57	0.001	As Carbon	0.57	0.001	8.98	74
Boiler 7	Vibrating Grate	01/06/01	172,827	335,314	328,333	675.11	93.77	145.36	0.215	0.83	0.001	As Carbon	0.83	0.001	8.95	75
Boiler 7	Vibrating Grate	01/09/02	130,764	283,174	324,545	691.41	96.03	118.19	0.171	24.93	0.036	As Carbon	24.93	0.036	6.67	47
Boiler 7	Vibrating Grate	01/09/02	136,455	292,108	331,714	706.88	98.18	137.64	0.195	75.76	0.107	As Carbon	75.76	0.107	6.43	44
Boiler 7	Vibrating Grate	01/09/02	140,707	305,155	333,429	708.68	98.43	136.35	0.192	141.65	0.200	As Carbon	141.65	0.200	6.41	44
Boiler 7	Vibrating Grate	11/15/02	148,856	299,613	363,659	772.94	107.35	148.92	0.193	6.61	0.009	As Carbon	6.61	0.009	6.56	45
Boiler 7	Vibrating Grate	11/15/02	155,948	304,949	343,200	727.96	101.11	155.25	0.213	5.07	0.007	As Carbon	5.07	0.007	7.65	56
Boiler 7	Vibrating Grate	11/15/02	150,966	297,647	334,737	709.05	98.48	141.14	0.199	4.48	0.006	As Carbon	4.48	0.006	7.96	60
Boiler 7	Vibrating Grate	12/30/03	144,480	287,753	354,783	744.67	103.43	118.00	0.158	47.43	0.064	As Carbon	47.43	0.064	6.36	44
Boiler 7	Vibrating Grate	12/30/03	148,005	283,321	329,250	688.40	95.61	159.13	0.231	18.09	0.026	As Carbon	18.09	0.026	6.99	50
Boiler 7	Vibrating Grate	12/30/03	145,898	281,972	338,630	707.48	98.26	156.26	0.221	12.69	0.018	As Carbon	12.69	0.018	6.58	46
Boiler 7	Vibrating Grate	02/04/05	165,392	296,331	232,174	494.28	68.65	120.68	0.244	4.12	0.008	As Carbon	4.12	0.008		
Boiler 7	Vibrating Grate	02/04/05	161,579	296,174	228,000	487.84	67.76	90.57	0.186	4.44	0.009	As Carbon	4.44	0.009		
Boiler 7	Vibrating Grate	02/04/05	159,426	285,860	223,099	475.52	66.04	95.57	0.201	0.89	0.002	As Carbon	0.89	0.002		
	Number of Runs		18		18	18	18	18	18	18	18		18	18	15	15
	MEAN		**151,164**		**322,931**	**676.0**	**93.89**	**135.59**	**0.202**	**20.92**	**0.030**		**20.92**	**0.030**	**6.79**	**49**
	MINIMUM		130,764		223,099	475.5	66.04	90.57	0.158	0.57	0.001		0.57	0.001	3.60	21
	MAXIMUM		179,424		369,429	772.9	107.35	159.54	0.244	141.65	0.200		141.65	0.200	9.08	75
	STD DEVIATION		15,004		46,146	93.3	12.96	20.21	0.023	35.88	0.050		35.88	0.050	1.58	16
	95% CL OF RUNS		**181,171**		**415,224**	**862.6**	**119.81**	**176.00**	**0.248**	**92.69**	**0.130**		**92.69**	**0.130**	**9.96**	**82**
	GEOMETRIC MEAN		**150,476**		**319,296**	**669.0**	**92.92**	**134.00**	**0.200**	**6.62**	**0.01**		**6.62**	**0.010**	**6.60**	**47**

Notes:
lb/hr = pounds per hour.
lb/MMBtu = pounds per million British thermal units.
lb/ton = pounds per ton.
MMBtu/hr = million British thermal units per hour.
TPH = tons per hour.

Footnotes:
[1] Assumed 3,600 Btu/lb average heat content for wet bagasse, except where noted.
[2] Based on actual reported data.
[3] If reported as propane, it was converted to carbon by the folloing equation:
lb/hr as carbon = lb/hr as propane x ((3*12.011)/44.09)
where 44.09 is the MW of propane and 12.011 is the MW of carbon.