UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

MAR 1 3 2010

RECEIVED
MAR 17 2010
DIVISION OF AIR
RESOURCE MANAGEMENT

Joseph Kahn, Director
Division of Air Resource Management
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee Florida 32399-2400

Dear Mr. Kahn,

Thank you for sending the technical evaluation/preliminary determination and draft prevention of significant deterioration (PSD) permit for Highlands Ethanol Facility (HEF) dated October 23, 2009. The project is for the construction of a large commercial application cellulosic ethanol process producing an annual capacity of 39.4 million gallons per year. HEF will generate its own process steam fuel consisting of biomass (stillage cake) from fermentation and distillation and biogas from the onsite waste water treatment plant Natural gas, depending on local availability, and ultra low sulfur diesel (ULSD) fuel oil with a maximum sulfur concentration of 0.0015% or propane will be used as back up fuels. Total emissions from the proposed project are above the thresholds requiring PSD review for nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter ($PM/PM_{10}/PM_{2.5}$), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

Based our review of the PSD application, preliminary determination/statement of basis and draft PSD permit, we have the following comments:

1. On January 22, 2010, EPA signed into law a new National Ambient Air Quality Standard (NAAQS) for nitrogen dioxide (NO_2). The new standard is a 1-hour standard set at the level of 100 parts per billion (ppb). The effective date of the new NAAQS will be April 12, 2010. If the final PSD permit for Highlands Ethanol Facility has not been issued by the time the new NAAQS is effective, the Division will need to include the appropriate air quality analysis before a final PSD permit is issued.

2. According to page 12 of the Technical Evaluation and Preliminary Determination, the applicant intended to rely on the PM_{10} Surrogate Policy to satisfy the applicable $PM_{2.5}$ requirements. However, the applicant did not address the appropriateness of the PM_{10} BACT determination as a substitute for a BACT analysis of $PM_{2.5}$ emissions. The applicant should either demonstrate that EPA's PM_{10} Surrogate Policy is appropriate for this project and explain the current technical difficulties that make $PM_{2.5}$ NAAQS compliance modeling infeasible, or perform a $PM_{2.5}$ NAAQS compliance analysis following accepted procedures that include representative ambient background concentrations. To this end, we are in the process of developing guidance for performing an acceptable $PM_{2.5}$ analysis which we plan to make available shortly for use by states and PSD permit applicants.

3. Section 5.3.3.2 Steam Production Backup Boiler (page 5-34) of Section 5.3 BACT evaluation for the Highlands Ethanol Project states "Proven add-on NO_x control technologies include SCR and SNCR...." An explanation is included within the section as to why the add on controls are not considered to be cost effective but a detailed top down BACT analysis, including the calculations was not included. A top down BACT must be conducted before any sort of cost implications can be considered.

4. Page 33 of the HEF draft permit states that the hours of operation for the backup boiler is restricted to 6000 hours in any consecutive 12 month period with a additional reduction in hours of operation when ULSD is used to fuel the boiler. However, page 23 of the Technical Evaluation and Preliminary Determination states that the hours of operation for the backup boiler is limited to 3000 hours in any consecutive 12 month period. These sections are in conflict. Please correct to reflect the appropriate limit in hours of operation.

If you have any questions regarding these comments or need additional information, feel free to contact Randy B Terry at 404-562-9032.

Sincerely,

Gregg M. Worley

Gregg M. Worley
Chief
Air Permits Section

To File

amec

April 14, 2009

Mr. Al Linero
Program Administrator
Special Projects Section
Florida Department of Environmental Protection
Bob Martinez Center
2600 Blairstone Road, MS #5505
Tallahassee, FL 32399-2400

RECEIVED

APR 17 2009

BUREAU OF AIR REGULATION

Re: Request for Additional Information DEP File Number: 0550061-001-AC

Dear Al:

On behalf of Highlands Ethanol LLC (Highlands Ethanol), AMEC Earth & Environmental (AMEC) is providing responses to the information requested in your March 17, 2009, letter to Mr. Charles Davis III regarding the February 16, 2009, application for an Air Construction Permit for the proposed Highlands Ethanol facility. The format of this letter provides your request in italics followed by the response.

1. *<u>Feedstock Storage.</u> In Section 2, page 2-2 of the air permit construction application, it is stated that there will not be a feedstock storage pile. Does this preclude a temporary storage pile? If there is a temporary storage pile, what is its expected size and how long will the feedstock be stored before it is feed into the hydrolysis process?*

   The facility will include short-term staging of feedstock and supplemental biomass. We will be providing information on the scale and duration of this staging in separate correspondence.

2. *<u>BACT Analysis Cost Analyses.</u> In Section 5 of the permit application a Prevention of Significant Deterioration (PSD), Best Available Control Technology (BACT) analysis was performed for criterion air pollutants. However, a ranking by costs for each BACT determination was not performed. For example, a cost ranking for NO_x control by Selective Catalytic Reduction (SCR) versus Non-Selective Catalytic Reduction (SNCR) technologies was not provided. Please provide cost rankings of the different BACT determinations presented in Section 5 of the application. [Rule 62-4.070, F.A.C. Reasonable Assurance]*

   Section 5 of the application provides a top down BACT analysis for each pollutant by process. Using U.S. Environmental Protection Agency's (USEPA) top down BACT methodology, the available control alternatives for each process/pollutant combination were first evaluated. Next, the technical feasibility of each option for the proposed Project was determined and the top level of control identified. If the top level of control was selected, no further analysis is required. For the VOC emitting process sources, the top level of control

AMEC Earth & Environmental, Inc.
15 Franklin Street
Portland, ME 04101
Tel (207) 879-4222
Fax (207) 879-4223

amec

was selected in each case and therefore, no cost analysis was presented for these operations.

For the biomass boilers, the available control alternatives were evaluated for technical feasibility on a pollutant specific basis. With the exception of NO_x, the top level of control was selected for each PSD pollutant emitted from the biomass boilers. For NO_x emissions from the biomass boilers, SCR was identified as the top level of control. Because SCR was not selected as BACT, Section 5.3.3.1 of the application presented an analysis of economic, energy, and environmental impacts. The economic feasibility analysis is presented in Tables 5-2 and 5-3 of the application and show the cost effectiveness to be $27,000 per ton of NO_x removed, which is not considered cost effective. The next level of control, SNCR was selected as BACT and as such no further economic analysis was presented.

It was also noted in the application that in the case of the fluidized bed biomass boilers, the SCR would have to be located within the heat exchanger section upstream of the other air pollution control systems, including the fabric filter, otherwise the system would require flue gas reheat. The high particulate loading of the flue gas prior to the fabric filter would subject the catalyst to fouling and degradation. A more detailed discussion of the potential for catalyst fouling is provided below in response to Request No. 4. The use of flue gas reheat for a cold side application of the SCR would result in additional energy and environmental impacts as an additional 629,700 cubic feet of natural gas would have to be combusted for each ton of NO_x removed by the SCR. This in turn would increase emissions of NO_x, CO, VOC, PM, SO_2, and CO_2.

3. *BACT Options. In Section 5 of the permit application the BACT determinations for each emissions unit at the facility are described. Please provide a discussion and summary table of the BACT utilized for similar emissions units with their permitted limits at other similar ethanol plants in the United States. [Rule 62-4.070, F.A.C. Reasonable Assurance]*

   BACT tables for previous determinations for each process type and pollutant are provided in detail in Appendix E "USEPA's RACT/BACT/LAER Clearinghouse Data" of the permit application. A discussion of the tables presented in Appendix E is provided in Section 5 of the PSD Application. Because Highland Ethanol's cellulosic ethanol production process is a new proprietary process and differs from the corn based ethanol production facilities, each part of the process was evaluated for analogous processes in fuel and beverage alcohol ethanol production and biodiesel manufacturing. In addition, supporting project operations such as the biomass boiler were also compared to similar processes at other types of facilities. Section 5.3 of the application discusses specific projects that were reviewed in addition to the information contained in the RACT/BACT/LAER Clearinghouse. Tables E-1 through E-23 present BACT determinations identified for similar process units.

amec

4. *<u>SCR versus SNCR for NO_x Control.</u> Please provide documentation supporting the conclusion provided in the air permit application that use of a SCR prior to the Particulate Matter (PM) control device is not practical due to the PM in the exhaust stream degrading catalyst performance. [Rule 62-4.070, F.A.C. Reasonable Assurance]*

   The information regarding operational issues with placing SCR equipment upstream of the particulate control device is based on discussions with AMEC Power and Process boiler design engineers, information obtained from CFB boiler and SCR vendors, and published studies. As previously noted, the SCR must be placed in a location such that flue gas temperature is optimal for performance of the catalyst. As detailed in a 2005 study for the International Energy Agency on biomass impacts on SCR performance, when firing biomass, high levels of alkali aerosols are present in the flue gas. The impact of the alkali aerosols on the SCR catalyst performance was documented in this study as well as several others. Documentation from this study report are included in Attachment A. Alkali aerosols from biomass combustion (calcium and potassium in particular) in high concentrations have been shown to irreversibly poison the catalyst and shorten its useful lifetime.

   In another application of a co-fired CFB boiler, SCR was initially installed prior to the dust removal equipment to ensure proper reaction temperatures. However, due to the high particulate loading of the flue gas, maintenance costs of the SCR were very high and repeated off-line washing of the catalyst was necessary. As a result, the SCR unit was replaced with SNCR. A vendor summary of this application is also presented in Attachment A.

5. *<u>Biomass Boiler PM Estimates.</u> In Table 1 on page ES-4 of the permit application, the PM emissions estimates for the two biomass boilers are 17.3 tons per year (tpy) for each boiler. However, on pages 123 and 124 of the application, the estimates of PM emissions for each biomass boiler are 86.7 tpy. Pease explain this discrepancy. [Rule 62-4.070, F.A.C. Reasonable Assurance]*

   The application forms contain a typographical error on these pages. The annual PM emissions on the forms should be 8.67 tons per year instead of 86.7 tons per year. In addition, the pound per hour value for PM on these pages should be 1.98 lb/hour instead of 19.8. Corrected forms are included in Attachment B of this submittal.

6. *<u>Biomass Boiler Fuel Usage.</u> Throughout the air permit application, it is stated that the biomass boilers will be capable of firing stillage cake, biogas, natural gas, propane and Ultra-Low Sulfur Diesel (ULSD). Please provide estimates of the air emissions from the boilers when firing each of these different fuels along with the expected amount of time and percentage of total fuel usage, based on heat input rate, that each fuel type will be used. [Rule 62-4.070, F.A.C. Reasonable Assurance]*

As discussed with David Read on March 20, 2009, annual potential emissions for the biomass boilers were based on the proposed BACT emission limits for the worst-case fuel. To provide FDEP additional data on a fuel specific basis, we are providing the hourly emission rates by fuel type and estimate of the annual anticipated use of each type of fuel in Attachment C. In discussions with David Read, it is our understanding that this information will be used to establish short term emission limits (lb/MMBtu) only and the annual percentages by fuel type will not be incorporated as a permit limitation.

7. *<u>Backup Boiler Emissions.</u> In the air permit application, emissions estimates for the backup boiler were not provided when firing natural gas, biogas, propane or ULSD. Please provide emissions estimates for the backup boiler when firing each of these fuel types. [Rule 62-4.070, F.A.C. Reasonable Assurance]*

   As discussed with David Read on March 20, 2009, the back-up boiler will only be operated when the biomass boilers are shut down. Therefore, as a worst case estimate, annual potential emissions assume the biomass boilers operate for 8,760 hours per year each with no emissions from the back-up boiler. A table of emission factors and hourly emissions for the back-up boiler firing natural gas, biogas and fuel oil is included in Attachment C.

8. *<u>Backup Generator and Fire Pump (Emergency Engines).</u> In section 5.3.3.3 of the air permit application, the emergency generators and fire pump proposed for the project are briefly discussed. Are the generators and fire pump models planned for use for this project available? If so, please provide this information. [Rule 62-4.070, F.A.C. Reasonable Assurance]*

   The vendor and models for this equipment have not yet been selected.

9. *<u>EPA Exemption Letters.</u> In Section 4.2 of the air permit application, it is indicated Highlands Ethanol LLC has requested site-specific exemptions from the U.S. Environmental Protection Agency (EPA) Region 4 with regard to the below listed New Source Performance Standards (NSPS). What is the status of these exemption requests?*

   - *40 CFR 60 Subpart NNN – Standards of Performance for Volatile Organic Compound (VOC) Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations.*

   - *40 CFR 60 Subpart RRR – Standards of Performance for Volatile Organic Compound (VOC) Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Operations.*

   [Rule 62-4.070, F.A.C. Reasonable Assurance]

amec

Highlands Ethanol received a site specific exemption for NSPS Subparts NNN and RRR from EPA Region IV in a letter dated March 26, 2009. A copy of the exemption letter is included as Attachment D to this letter.

10. Commercial, Residential and Other growth. *An application must include information relating to the air quality impacts of, and the nature and extent of, all general, commercial, residential and other growth which has occurred since August 7, 1977, in the area the facility or modification would affect. Please provide information to satisfy this requirement. [Rule 62-4.070, F.A.C. Reasonable Assurance]*

The proposed project site is owned by Lykes Bros. Inc. (Lykes) and is generally flat with terrain gently sloping from north to south toward SR 70. The site is surrounded on four sides by additional Lykes property. Further south of the Site is SR 70, and nearby to the southwest is located the Morris #3 Glades Electric Cooperative, Inc. electrical substation.

To assess the land use history for the site and adjacent properties, AMEC reviewed historic aerial photographs from EDR (Environmental Data Resources, Inc [EDR], *The EDR Historical Topographic Map Report*, Wheelers Farms Road, Milford, Connecticut, 06461 August 26, 2008).

Aerial photographs for the years 1944, 1957, 1970, 1978, 1986, 1999, and 2005 were reviewed and are provided in Attachment E. Based on information in the photographs, the site and surrounding properties appear to be undeveloped both historically and currently. Pertinent details of the reviewed photographs are provided in Table 1. Based on this assessment, it can be concluded that the site and land in the vicinity of the site has had little to no growth since the 1940s.

Table 1. Review of Historic Aerial Photographs of Proposed Project Site

Year	Notes On Observations
1944	The site and surrounding properties appear to be undeveloped pasture land.
1957	The site and surrounding properties appear similar to the 1944 aerial photograph.
1970	The site and surrounding properties appear to be undeveloped pasture land. Irrigation and/or dewatering measures are visible.
1978	The site and surrounding properties appear similar to the 1970 aerial photograph.
1986	The site and surrounding properties appear similar to the 1978 aerial photograph.
1999	The site and surrounding properties appear similar to the 1986 aerial photograph.
2005	The site and surrounding properties appear similar to the 1999 aerial photograph.

11. <u>Surface Characteristics.</u> *Recent modeling guidance suggests and the Department requires that AERMET surface characteristics of the facility site and the National Weather Service site be compared to ensure conservatism. Please provide a model run for each averaging time with surface characteristics from the facility site with National Weather Service upper air to ensure that your analysis was most representative.*

    AMEC has created two sets of processed meteorological data, one based on the surface characteristics of the proposed facility site and the other based on the surface characteristics of the NWS site at West Palm Beach Airport. AMEC then ran AERMOD for the significant impact analysis and interactive analysis using both sets of meteorological data. The originally submitted conclusions of the dispersion modeling analysis remain unchanged as a result of this additional modeling, however the values presented in the tables have changed. The short-term average predicted concentrations were generally greater when using the meteorological data based on the surface characteristics of the proposed facility site. The annual average predicted concentrations were generally greater when using the meteorological data based on the surface characteristics of the NWS site. The updated tables are provided in Attachment F.

12. <u>Class I Impact Analysis.</u> *Please provide a table with the Class I Significant Impact Analysis impacts. [Rule 62-4.070, F.A.C. Reasonable Assurance]*

    A Class 1 area Significant Impact Area screening modeling analysis was conducted to predict impacts from the project at the Everglades National Park and the Chassahowitzka Wilderness Area. The project notification and the results of these analyses provided to the corresponding Federal Land Managers (FLM) for each area demonstrate that maximum predicted concentrations at both Class 1 areas are well below the FDEP and USEPA Class 1 Significant Impact Levels. The FLM submittals and summary tables of modeling results are provided in the application in Appendix H, "FLM Notification Letters".

13. <u>Significant Impact Area.</u> *Please provide a table or electronic spreadsheet with the list of sources used for the Increment and National Ambient Air Quality Analysis, including a list of all sources eliminated due to screening methods. Please verify that all sources within the Significant Impact Area (not including the 50 km buffer) were modeled. [Rule 62-4.070, F.A.C. Reasonable Assurance]*

    Highlands Ethanol obtained an inventory of interactive sources within a 50 kilometer radius of the Project to include in the interactive increment and NAAQS modeling analyses. These sources are listed in the application in Appendix G, "Interactive Source Data". None of the facilities are located within the predicted significant impact areas of the proposed project. FDEP allows for facilities that are more distant from the project site to be eliminated from the interactive modeling analysis by applying the "20D" rule, a screening method developed by the North Carolina Department of Natural Resources and Community Development (NCDNRCD, 1985). This process is discussed in Section 6.2.2, and the resulting calculations are provided in Appendix G. Of the seven sources selected for interactive modeling, five are electric generating stations, and the remaining two are US Sugar's Clewiston mill and the Okeechobee Landfill. Locations of the facilities with respect to the Project site are presented in Figure 6-7 of the application.

14. *Truck Traffic. Regarding the particulate matter analyses provided to the Department, please indicate why truck traffic was not modeled. [Rule 62-4.070, F.A.C. Reasonable Assurance]*

AMEC provided fugitive PM emissions calculations for both unpaved and paved roads for the purposes of comparing total potential emissions to regulatory applicability thresholds. AMEC notes, however, that the AP-42 techniques employed have a great deal of uncertainty when applied to the agricultural products industry and specifically cellulosic ethanol production facilities. Because of this uncertainty and the additional uncertainty added by the dispersion model, AMEC believed it was inappropriate to attempt to quantify the ambient impacts of fugitive emissions from roadways. Nevertheless, best management practices will be employed per the air permit application to minimize these fugitive dust emissions. The following items identify the problems inherent with using the AP-42 techniques, and provide a rationale for not modeling the truck traffic.

Unpaved Roads

USEPA released a final version of AP-42 Chapter 13.2.2 in November 2006.

A. The derivation of the predictive emission model for dry industrial unpaved roads relies on values of average vehicle weight and road surface silt content. A separate predictive emission model is provided for dry public unpaved roads.

B. For dry industrial unpaved roads, the range of speeds tested in deriving the predictive equation is 5 mph to 43 mph. AP-42 does not state whether the traffic was free flowing or stop and go, but the background information provided suggests that stop and go traffic would decrease the quality of the calculation. Vehicles used on the proposed facility's unpaved roads will operate at speeds in the low end of the range and will follow a stop and go pattern, bringing the relevance of the emission model into question for Highlands Ethanol.

C. The predictive equation for dry industrial unpaved roads using site specific inputs is assigned a quality rating of B. If site-specific data are not available, the quality rating drops to D. While the quality ratings are said to apply to the range of source conditions, AP-42 also states that the quality ratings pertain to the mid-range of the measured source conditions. As stated previously, the vehicles expected to be operating on the proposed facility's unpaved roads operate at the low end of the speed range and follow a stop and go pattern. Further, given that the roads are not currently constructed and final design is not complete, site-specific analysis of the road surface cannot be performed.

D. To account for the effect of moisture, USEPA applies a term to reflect the percentage of days with precipitation greater than 0.01 inches. However, when this factor is incorporated, USEPA drops the rating by one letter. So if site-specific data were available, the predictive equation's rating would drop to C when incorporating precipitation events. If default values are used for silt content and/or mean vehicle weight, the rating drops to E when incorporating precipitation events.

E. USEPA states that the predictive model cannot be used to estimate emissions from chemically treated roads. Highlands Ethanol is considering chemical treatment of its unpaved road surfaces, so AP-42 cannot be applied accurately.

F. AP-42 recommends the use of a gravel surface or adding pavement to reduce fugitive emissions. Gravel surfaces will likely be used at the proposed facility as part of the best management practices to reduce fugitive emissions.

G. Review of the data sources for deriving the predictive emission model for industrial unpaved roads reveals that none of the industries evaluated are part of the agricultural products industry. The industrial sources included in the derivation of the predictive emission model are as follows:

   a. Construction sites in Nevada and California,

   b. Stone crushing plants in North Carolina and Kansas,

   c. Surface coal mines in Wyoming, North Dakota, and New Mexico,

   d. Integrated iron and steel plants in Pennsylvania, Indiana, Missouri, Texas, and Ohio,

   e. An unidentified coal-fired power plant,

   f. Sand and gravel processing plants in Kansas, and

   g. Copper smelter in Arizona.

   The background document provides numerous discussions regarding the need to identify emissions from specific industries. As noted previously, particles in the agricultural products industry likely have different particle size distributions, densities, moisture content and silt content.

Paved Roads

USEPA released a final version of AP-42 Chapter 13.2.1 in November 2006.

A. The predictive model for dry paved roads emissions is an empirical model derived by regressing data collected during road tests. All road tests were conducted with free flowing traffic traveling at constant speed on a level surface. Therefore, if the traffic is not free flowing or at constant speed (as will be the case at the proposed facility), modeled emissions will not be accurate.

B. Although USEPA gives the model a rating of A for PM_{10} and B for $PM_{2.5}$, they downgrade the rating to C and D, respectively, if site-specific data on road surface silt content and average vehicle weight cannot be determined (i.e., when default values are used in lieu of site-specific data).

C. USEPA uses the following statement to caution users who use the dry paved road fugitive dust equation:

   "Users are cautioned that application of equation 1 outside of the range of variables and operating conditions specified above, e.g., application to roadways or road networks with speeds below 10 mph and with stop-and-go traffic, will result in emission estimates with a higher level of uncertainty. In these situations, users are encouraged to consider alternative methods that are equally or more plausible in light of local emissions data and/or ambient concentration or compositional data."

   In this case, USEPA does not downgrade the quality rating of the calculation if the traffic is stop and go and/or less than 10 mph. Rather, they encourage the use of alternative methods (no references are provided for alternative methods). Traffic on the proposed facility's paved roads will be limited to speeds less than 10 mph and will be stop and go in nature. Therefore, this factor will not result in accurate estimates for Highlands Ethanol's paved roads.

D. The primary predictive equation for paved roads does not incorporate emission reductions resulting from wet conditions (e.g., rain). USEPA does present two additional models that incorporate wet conditions, but they are short-term equations (hourly or daily). Use of these equations results in a quality rating reduction of one letter, which would be B (PM_{10}) and C ($PM_{2.5}$) if site specific data are available, and D (PM_{10}) and E ($PM_{2.5}$) if default values are used.

E. Control techniques include preventive measures (such as paving intersecting unpaved roads to reduce trackout) and mitigative measures (such as vacuum sweeping). While the effectiveness of these techniques is highly variable, USEPA maintains that the silt loading term in the predictive equation accounts for these controls. Highlands Ethanol intends to maintain a vacuum sweeping program.

F. As for the derivation of emission factors for industrial unpaved roads, none of the supporting data are obtained from facilities in the agricultural products industry. Rather, the empirical model is based on data collected from public paved roads as well as data collected from paved roads located at mineral products and metallurgical facilities. These data are combined together to obtain a single predictive emission model that applies to both public and industrial paved roads. As noted previously, particles in the agricultural products industry likely have different particle size distributions, densities, moisture content and silt content.

We believe that these responses will satisfy your data requests. If you have any questions, please feel free to call me at (207) 879-4222, ext. 37.

Very truly yours,
AMEC Earth & Environmental

Jeffrey R. Harrington

Jeffrey R. Harrington, P.E.
Senior Project Engineer

cc: T. Eves – Highlands Ethanol
A. Smithe – Highlands Ethanol
C. Davis – Highlands Ethanol
L. Modica – AMEC
K. Jameson – AMEC

From: Harrington, Jeff [mailto:jeff.harrington@amec.com]
Sent: Thu 9/17/2009 4:01 PM
To: Read, David
Cc: Linero, Alvaro; Tim.Eves@vercipia.com
Subject: Additional Information and Comments on Draft Permit Documents

Dear David,

On behalf of Highlands Ethanol LLC (Highlands Ethanol), AMEC Earth & Environmental (AMEC) is providing additional information requested by the Florida Department of Environmental Protection (FDEP). Specifically, we are providing information regarding biomass boiler heat input monitoring, further justification for our proposed NO_x limit for the biomass boilers, a sample Leak Detection and Repair (LDAR) plan, and the fuel oil storage tank size for the biomass boiler should natural gas not be available. We are also providing comments on the partial draft PSD Permit and Technical Support Documents provided by the FDEP on August 24 and 25, 2009 and are also attaching marked up versions of these documents to assist in your review. Comments on the Technical Support Documents provided by FDEP on September 11 will be provided in separate correspondence.

BIOMASS BOILER HEAT INPUT MONITORING

Highlands Ethanol project design engineers evaluated FDEP's proposed draft method for monitoring biomass boiler heat input. The variable nature of the fuel that will be burned in the biomass boilers presents some challenges to performing the method as proposed. In the case of biomass such as stillage cake, which has a high moisture content compared to other fuels proposed for the boiler, boiler energy will be expended to evaporate that moisture and the boiler efficiency will be reduced. In the case of biogas, the boiler will operate at a higher efficiency. The use of the proposed method will not be accurate when combusting varying ratios of stillage cake and biogas. The proposed heat input calculation in the method as proposed will be biased either high or low depending on the fuel mix. To improve the accuracy of the method, Highlands Ethanol proposes changes as noted by additions (underlined font) and deletions (strikeout font):

Boiler Performance Test: Within 180 days of first fire on the primary fuels (stillage and biogas with natural gas for flame stabilization); the permittee shall conduct a test to determine the boiler thermal efficiency. The test shall be conducted in general abbreviated accord with ASME PTC 4, 1998. The abbreviated test procedure shall be agreed upon by all parties. The test shall be conducted when firing only the primary fuels with as close of fuel mix and heating values to the boiler design fuel mix and heating value as practical and shall be at least three hours long. The boiler steam conditions and production rate shall be monitored and recorded during the test. The primary fuels firing rates (tons per hour and cubic feet per minute as appropriate) shall be calculated and recorded based on the steam parameters. A sample of the as-fired stillage shall be analyzed for the heating value (Btu/lb) and moisture content (%). A sample of the as-fired biogas shall be analyzed for the heating value (Btu/ft^3). The actual heat input rate (MMBtu/hour) shall be determined using two methods: (a) steam parameters with enthalpies and the measured thermal efficiency, and (b) steam parameters with enthalpies and the design boiler thermal efficiency. Results of the test shall be submitted to the Compliance Authority within 45 days of completion. The boiler thermal efficiency test shall be repeated during the 12-month period prior to renewal of any operation permit. If the tested boiler thermal efficiency is less than 90% of the design boiler thermal efficiency, then the tested thermal efficiency shall be used in any future calculations of the heat input rate until a new test is conducted.

A sample form for this test procedure is attached.

NO_X LIMIT FOR BIOMASS BOILERS

An air permit application was recently filed with FDEP for a 50 MW biomass bubbling fluidized bed (BFB) power plant (ADAGE Hamilton LLC). ADAGE is proposing to employ SCR for NO_X control with an annual average limit of 0.07 lb/MMBtu which enables the facility to be permitted as a minor source. Highlands Ethanol proposed SNCR (not SCR) and a NO_X emission limit of 0.075 lb/MMBtu as BACT. Based on the control technology and NO_X emission limit specified in this permit, FDEP questioned the ability of Highlands Ethanol's biomass boilers to meet a NO_X limit of 0.07 lb/MMBtu as BACT to be consistent with the ADAGE's proposed NO_X limit.

A key difference between the projects is the proposed biomass to be fired in the boiler. ADAGE is proposing to use untreated woody biomass, primarily in the form of pre-processed chips. Highlands Ethanol is proposing to primarily use process stillage solids, which is a new fuel for which there is no current commercial scale operating data available. From laboratory analyses, Highlands Ethanol knows that there can be considerable natural variability in this fuel due to natural variation in the energy crops such as that caused by plant age at harvest and weather conditions. Among the fuel characteristics that are affected by this variability is its nitrogen content, which generally averages from 2 to 3 times (up to 0.49% N) the content of whole tree wood chips. Further, variable amounts of nitrogen in Highlands Ethanol's boiler fuel may occur due to nutrient additions to propagate the fermentation organisms. Boiler vendor guarantees of 0.07 lb/MMBtu NO_X could be obtained for biomass fuels that are well known and tightly defined, such as those proposed for Adage. However, because of the higher nitrogen content of the biomass fuels to be used at Highlands Ethanol and the greater variability of the feedstock composition, the biomass fuel to be combusted at Highlands Ethanol does not have a specific fuel definition that would support a limit of 0.07 lb/MMBtu.

Another difference to be considered is that Highlands Ethanol's proposed BACT limit is based on a 30-day rolling averaging period while ADAGE's proposed BACT limit is based on an annual averaging period. The longer averaging period proposed by ADAGE allows for increased flexibility in addressing NO_X emissions variability.

Based on these differences presented, Highlands Ethanol requests that the NO_X BACT limit be established as 0.075 lb/MMBtu based on a 30 day rolling average.

SAMPLE LEAK DETECTION AND REPAIR (LDAR) PLAN

FDEP requested a sample or "skeleton" LDAR plan for fugitive VOCs per Highlands Ethanol's proposed BACT and 40 CFR 60 Subpart VVa. Attached is a procedure developed for the demonstration and pilot plants that are of similar plant design and operated by Verenium Biofuels Louisiana in Jennings, Louisiana.

FUEL OIL STORAGE TANK

In the event natural gas is not available at the time the facility commences operation, ULSD fuel oil will be used in the boilers for start-up and stabilization. If ULSD is required, the ULSD storage tank will be designed to provide a three-day supply and will have a capacity of 100,000 gallons. The tank will be of a fixed roof design constructed of carbon steel based on API 650 standards. The tank vent will be equipped with an end-line-vacuum breather pressure/vacuum vent valve. The tank dimensions will be a diameter of 26 feet by a height of 26 feet. The tank will be contained in a concrete dike for spill containment.

REVIEW OF DRAFT PERMIT

We have reviewed the incomplete draft PSD permit for Highlands Ethanol, as delivered by FDEP on August 25, and have prepared comments for your consideration. The incomplete draft PSD permit is attached with Highlands Ethanol's comments included as tracked changes, comment boxes, and pink highlights (note that green and yellow highlights were inserted by FDEP). A summary of key comments is provided as follows.

1. The identification of emission units (EUs) on page 3 of 45 is somewhat different than the identification of emission units proposed in Highlands Ethanol's application. The primary differences are: the addition of feedstock delivery and handling as EU001, the combination of the wastewater anaerobic and aerobic processes into a single EU (EU007), the separation of the biomass boilers into individual EUs (EU008 and 009), and the inclusion of the miscellaneous non-VOL storage tanks as EU013. While most of these changes are acceptable, Highlands Ethanol requests that the non-VOL storage tanks be included in the permit as insignificant emission units because there would be little or no VOC emissions from these tanks and there are no underlying applicable requirements for these.

2. The draft permit did not yet include conditions for EUs 002-007 which include:

    - 002 Hydrolysis, liquid/solids separation, neutralization
    - 003 Fermentation, distillation and bacteria/enzyme propagation
    - 004 Solids (stillage and gypsum) separation, dewatering and loadout
    - 005 Denaturing and product storage
    - 006 Product loadout and flare
    - 007 Wastewater treatment system, biogas conditioning and flare

We will review the conditions for these emission units once they become available.

3. Page 4 of 45, No. 3 Appendices, we request that the 40 CFR 63 Subpart A requirement be deleted. Because Highlands Ethanol is an area source with respect to HAPs and the facility will meet the requirements of 40 CFR

60 Subpart IIII for the emergency generators, there are no applicable requirements for the engines under 40 CFR 63.

4. Page 4 of 45, No. 3 Appendices, references NSPS Subpart Da. This should be changed to Subpart Db. In addition, there is no Appendix for 40 CFR 60 Subpart IIII listed, so it should be added to the list.

5. Page 23 of 45, No. 3 authorized fuels, the biomass boilers fuel consumption percentages are annual estimates and not limits. This should be made clear in the permit. Short-term fuel consumption rates will be variable and need to be accommodated.

6. Page 23 of 45, No. 7f, the SO_2 emission limit for the biomass boilers (EU008 and EU009) that will be determined by stack testing is based on the proposed emission limit based on a 30 day averaging time. In the submitted BACT analysis, Highlands Ethanol also proposed a 3-hour block average of 0.14 lb/MMBtu. The emission limit to determine compliance during stack testing should be based on the proposed short term limit.

7. Page 30 of 45, No. 3, authorized fuels, back-up boiler fuel percentages are annual estimates and not limits. This should be made clear in the permit. Short-term fuel consumption rates will be variable and need to be accommodated.

8. Page 31 of 45, No. 7, requires a NO_x CEMS for the back-up boiler. 40 CFR 60 Subpart Db also allows use of a PEMS, and Highlands Ethanol requests the flexibility to install either a CEMS or a PEMS for the backup boiler.

9. Page 34 of 45, No. 5 requires VOC monitoring of the cooling tower water and development of a plan for this testing. Highlands Ethanol proposes to include this testing as part of the LDAR program.

10. Page 38 of 45 contains conditions for EU013. The VOL storage tanks listed in EU013 are already listed included in EU005 and these should be deleted. EU013 also includes the non-VOL storage tanks which were proposed as insignificant EUs. Highlands Ethanol requests that these also be deleted from EU013, in effect eliminating the need for EU013 (i.e., EU005 covers the VOL storage tanks and the balance of the storage tanks are insignificant emission sources).

REVIEW OF DRAFT TECHNICAL SUPPORT DOCUMENT (TSD) AND PRELIMINARY DETERMINATION (PD)

We have also reviewed the draft TSD/PD for Highlands Ethanol received on August 24 and 25, 2009, and have the prepared comments for your consideration. Because the file received from FDEP is a PDF, our comments are handwritten. These have been scanned and are attached. Please note that several comments are consistent with comments made on the draft permit. A summary of Highlands Ethanol's key comments is provided as follows.

1. Page 4 of 23, comments on the EU listing is the same as for the draft permit.

2. Page 5 of 23, Figure 5 Flow Chart. There are some corrections in associating processes on this chart with EUs. Some corrections to the associated descriptions on this page and on page 6 of 23 are also included.

3. Page 7 of 23, as previously noted, EU013 includes both the VOL storage tanks included in EU005 and includes the non-VOL storage tanks which were proposed as insignificant EUs. Highlands Ethanol requests that EU013 be deleted because EU005 already covers the VOL storage tanks and the non-VOL storage tanks are insignificant emissions sources.

4. Page 11 of 23, We request that the 40 CFR 63 Subpart A requirement be deleted. Because Highlands Ethanol is an area source with respect to HAPs and the facility will meet the requirements of 40 CFR 60 Subpart IIII for the emergency generators, there are no applicable requirements for the engines under 40 CFR 63.

5. Page 12 of 23. We made some minor comments on the BACT Review, Section 5.0.

6. Page 20 of 23, Table titled Maximum Air Quality Impacts from the Highlands Ethanol Project for comparison to the PSD Class 1 SILs has 0.99 mg/m^3 for 3 hour SO_2. The value listed in the permit application was 0.97 mg/m^3.

We appreciate your efforts on this project and look forward to completing the permitting process. If you have any questions, please feel free to call me at (207) 879-4222, ext. 37.

Regards,
Jeff Harrington

Al & David - I asked the engineering team to take another look at the maximum sulfur content of the stillage cake that was listed on the form in the permit application. Turns out that the value entered on the form was inaccurate. The calculation had captured the correct mass flow of sulfur, but only a fraction of the mass flow of stillage cake. When accounting for the total stillage cake mass flow to the boiler, the maximum sulfur content of the stillage cake is 0.08%. My apologies for the inconvenience this has caused.

My expectation is that you will want to revisit the technical documentation you have been preparing. I would be happy to talk with you about this and our other correspondence of today. I am available on Friday from 10:30 until 4:00 EDT if you wish to call.

Thanks again for your patience and attention to the permit application.

Jeff

SUMMARY SHEET

ASME TEST FORM
FOR ABBREVIATED EFFICIENCY TEST

PTC 4.1-a (1964)

	TEST NO.	BOILER NO.	DATE
OWNER OF PLANT	LOCATION		
TEST CONDUCTED BY	OBJECTIVE OF TEST		DURATION
BOILER, MAKE & TYPE		RATED CAPACITY	
STOKER, TYPE & SIZE			
PULVERIZER, TYPE & SIZE		BURNER, TYPE & SIZE	
FUEL USED	MINE	COUNTY	STATE	SIZE AS FIRED

PRESSURES & TEMPERATURES

1	STEAM PRESSURE IN BOILER DRUM	psia	
2	STEAM PRESSURE AT S. H. OUTLET	psia	
3	STEAM PRESSURE AT R. H. INLET	psia	
4	STEAM PRESSURE AT R. H. OUTLET	psia	
5	STEAM TEMPERATURE AT S. H. OUTLET	F	
6	STEAM TEMPERATURE AT R H INLET	F	
7	STEAM TEMPERATURE AT R. H. OUTLET	F	
8	WATER TEMP. ENTERING (ECON.) (BOILER)	F	
9	STEAM QUALITY % MOISTURE OR P. P. M.		
10	AIR TEMP. AROUND BOILER (AMBIENT)	F	
11	TEMP AIR FOR COMBUSTION (This is Reference Temperature) †	F	
12	TEMPERATURE OF FUEL	F	
13	GAS TEMP. LEAVING (Boiler) (Econ.) (Air Htr.)	F	
14	GAS TEMP. ENTERING AH (If conditions to be corrected to guarantee)	F	

UNIT QUANTITIES

15	ENTHALPY OF SAT. LIQUID (TOTAL HEAT)	Btu/lb	
16	ENTHALPY OF (SATURATED) (SUPERHEATED) STM.	Btu/lb	
17	ENTHALPY OF SAT. FEED TO (BOILER) (ECON.)	Btu/lb	
18	ENTHALPY OF REHEATED STEAM R. H. INLET	Btu/lb	
19	ENTHALPY OF REHEATED STEAM R. H. OUTLET	Btu/lb	
20	HEAT ABS/LB OF STEAM (ITEM 16 – ITEM 17)	Btu/lb	
21	HEAT ABS/LB R. H. STEAM (ITEM 19 – ITEM 18)	Btu/lb	
22	DRY REFUSE (ASH PIT + FLY ASH) PER LB AS FIRED FUEL	lb/lb	
23	Btu PER LB IN REFUSE (WEIGHTED AVERAGE)	Btu/lb	
24	CARBON BURNED PER LB AS FIRED FUEL	lb/lb	
25	DRY GAS PER LB AS FIRED FUEL BURNED	lb/lb	

HOURLY QUANTITIES

26	ACTUAL WATER EVAPORATED	lb/hr	
27	REHEAT STEAM FLOW	lb/hr	
28	RATE OF FUEL FIRING (AS FIRED wt)	lb/hr	
29	TOTAL HEAT INPUT $\frac{\text{Item 28} \times \text{Item 41}}{1000}$	kB/hr	
30	HEAT OUTPUT IN BLOW-DOWN WATER	kB/hr	
31	TOTAL HEAT OUTPUT $\frac{(\text{Item 26} \times \text{Item 20}) + (\text{Item 27} \times \text{Item 21}) + \text{Item 30}}{1000}$	kB/hr	

FLUE GAS ANAL. (BOILER) (ECON) (AIR HTR) OUTLET

32	CO_2	% VOL	
33	O_2	% VOL	
34	CO	% VOL	
35	N_2 (BY DIFFERENCE)	% VOL	
36	EXCESS AIR	%	

FUEL DATA

	COAL AS FIRED PROX. ANALYSIS	% wt		OIL	
37	MOISTURE		51	FLASH POINT F*	
38	VOL MATTER		52	Sp. Gravity Deg. API*	
39	FIXED CARBON		53	VISCOSITY AT SSU* BURNER SSF	
40	ASH		44	TOTAL HYDROGEN % wt	
	TOTAL		41	Btu per lb	
41	Btu per lb AS FIRED				
42	ASH SOFT TEMP.* ASTM METHOD			GAS	% VOL
	COAL OR OIL AS FIRED ULTIMATE ANALYSIS		54	CO	
43	CARBON		55	CH_4 METHANE	
44	HYDROGEN		56	C_2H_2 ACETYLENE	
45	OXYGEN		57	C_2H_4 ETHYLENE	
46	NITROGEN		58	C_2H_6 ETHANE	
47	SULPHUR		59	H_2S	
40	ASH		60	CO_2	
37	MOISTURE		61	H_2 HYDROGEN	
	TOTAL			TOTAL	
	COAL PULVERIZATION			TOTAL HYDROGEN % wt	
48	GRINDABILITY INDEX*		62	DENSITY 68 F ATM. PRESS.	
49	FINENESS % THRU 50 M*		63	Btu PER CU FT	
50	FINENESS % THRU 200 M*		41	Btu PER LB	

64	INPUT-OUTPUT EFFICIENCY OF UNIT %	$\frac{\text{ITEM 31} \times 100}{\text{ITEM 29}}$	

	HEAT LOSS EFFICIENCY	Btu/lb A. F. FUEL	% of A. F. FUEL
65	HEAT LOSS DUE TO DRY GAS		
66	HEAT LOSS DUE TO MOISTURE IN FUEL		
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2		
68	HEAT LOSS DUE TO COMBUST. IN REFUSE		
69	HEAT LOSS DUE TO RADIATION		
70	UNMEASURED LOSSES		
71	TOTAL		
72	EFFICIENCY = (100 – Item 71)		

* Not Required for Efficiency Testing

† For Point of Measurement See Par. 7.2.8.1-PTC 4.1-1964

CALCULATION SHEET

ASME TEST FORM FOR ABBREVIATED EFFICIENCY TEST

Revised September, 1965

OWNER OF PLANT		TEST NO.	BOILER NO.	DATE
30	HEAT OUTPUT IN BOILER BLOW-DOWN WATER = LB OF WATER BLOW-DOWN PER HR × $\left[\frac{\text{ITEM 15} \; .... - \; \text{ITEM 17} \; ....}{1000}\right]$ = ... kB/hr			
24	*If impractical to weigh refuse, this item can be estimated as follows* DRY REFUSE PER LB OF AS FIRED FUEL = $\frac{\text{\% ASH IN AS FIRED COAL}}{100 - \text{\% COMB. IN REFUSE SAMPLE}}$ CARBON BURNED PER LB AS FIRED FUEL = $\frac{\text{ITEM 43} \; ....}{100} - \left[\frac{\text{ITEM 22} \; ...... \times \text{ITEM 23} \; ....}{14{,}500}\right]$ = ...	NOTE: IF FLUE DUST & ASH PIT REFUSE DIFFER MATERIALLY IN COMBUSTIBLE CONTENT, THEY SHOULD BE ESTIMATED SEPARATELY. SEE SECTION 7, COMPUTATIONS.		
25	DRY GAS PER LB AS FIRED FUEL BURNED = $\frac{11CO_2 + 8O_2 + 7(N_2 + CO)}{3(CO_2 + CO)}$ × (LB CARBON BURNED PER LB AS FIRED FUEL + $\frac{3}{8}$ S) = $\frac{11 \times \text{ITEM 32} \; ..... + 8 \times \text{ITEM 33} \; ...... + 7\left(\text{ITEM 35} \; ...... + \text{ITEM 34} \; ......\right)}{3 \times \left(\text{ITEM 32} \; .... + \text{ITEM 34} \; ......\right)} \times \left[\text{ITEM 24} \; ...... + \frac{\text{ITEM 47} \; ......}{267}\right]$ = ...			
36	EXCESS AIR† = 100 × $\frac{O_2 - \frac{CO}{2}}{.2682N_2 - (O_2 - \frac{CO}{2})}$ = 100 × $\frac{\text{ITEM 33} - \frac{\text{ITEM 34}}{2}}{.2682\,(\text{ITEM 35}) - (\text{ITEM 33} - \frac{\text{ITEM 34}}{2})}$ = ...			

	HEAT LOSS EFFICIENCY	Btu/lb AS FIRED FUEL	$\frac{\text{LOSS}}{\text{HHV}}$ × 100 =	LOSS %
65	HEAT LOSS DUE TO DRY GAS = LB DRY GAS PER LB AS FIRED FUEL × C_p × ($t_{lvg} - t_{air}$) = $\frac{\text{ITEM 25}}{\text{Unit} \; ......}$ × 0.24 (ITEM 13) – (ITEM 11) ...... = ...	......	$\frac{65}{41}$ × 100 =	......
66	HEAT LOSS DUE TO MOISTURE IN FUEL = LB H_2O PER LB AS FIRED FUEL × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) – (ENTHALPY OF LIQUID AT T AIR)] = $\frac{\text{ITEM 37}}{100}$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) – (ENTHALPY OF LIQUID AT T ITEM 11)] = ...	......	$\frac{66}{41}$ × 100 =	......
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2 = $9H_2$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) – (ENTHALPY OF LIQUID AT T AIR)] = 9 × $\frac{\text{ITEM 44}}{100}$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) – (ENTHALPY OF LIQUID AT T ITEM 11)] = ...	......	$\frac{67}{41}$ × 100 =	......
68	HEAT LOSS DUE TO COMBUSTIBLE IN REFUSE = ITEM 22 ...... × ITEM 23 ...... = ...	......	$\frac{68}{41}$ × 100 =	......
69	HEAT LOSS DUE TO RADIATION* = $\frac{\text{TOTAL BTU RADIATION LOSS PER HR}}{\text{LB AS FIRED FUEL} - \text{ITEM 28} \; ....}$	......	$\frac{69}{41}$ × 100 =	......
70	UNMEASURED LOSSES **	......	$\frac{70}{41}$ × 100 =	......
71	TOTAL	......	......	......
	EFFICIENCY = (100 – ITEM 71)	......	......	......

† For rigorous determination of excess air see Appendix 9.2 – PTC 4.1-1964

* If losses are not measured, use ABMA Standard Radiation Loss Chart, Fig. 8, PTC 4.1-1964

** Unmeasured losses listed in PTC 4.1 but not tabulated above may by provided for by assigning a mutually agreed upon value for Item 70.

I. Purpose

The objective of this procedure is to establish guidelines for implementing and managing a Leak Detection and Repair (LDAR) program at the Verenium Biofuels Louisiana Ethanol Facility located in Jennings, Louisiana. The use of this procedure will assure compliance with federal and state regulations.

II. Scope

This procedure applies to all regulated components used in Volatile Organic Compound (VOC) service at the Verenium Biofuels Louisiana Ethanol Facility.

III. References

Compliance with this procedure will meet the requirements of the following regulations:

A. 40 CFR Part 60 Subpart VV
B. LAC 33: III. 2121

IV. Project Task

A. Task 1 - *Identification of Components*

- Identify each regulated component on a site plot plan or on a continuously updated equipment log.
- Assign a unique identification (ID) number to each regulated component.
- Purchase tags and physically locate each regulated component in the facility, verify its location on the piping and instrumentation diagrams (P&IDs) or process flow diagrams, and tag each component. Update the equipment log if necessary.
- Record each regulated component and its unique ID number in a log.
- Promptly note in the equipment log when new and replacement pieces of equipment are added and equipment is taken out of service.

B. Task 2 - *Leak Definition*

- Identify the leak definition for each regulated component. Leak definitions vary by regulation, component type, service (e.g., light liquid, heavy liquid, gas/vapor), and monitoring interval. Many equipment leak regulations also define a leak based on visual inspections and observations (such as fluids dripping, spraying, misting, or clouding from or around components), sound (such as hissing), and smell.

C. Task 3 - *Monitoring Components*

- Identify the monitoring intervals for each regulated component. Monitoring intervals vary according to the applicable regulation but are typically weekly, monthly, quarterly, or annually.

- Monitor all regulated components in accordance with EPA Method 21 (40 CFR Part 60 Appendix A) at the intervals specified by the regulations. Obtain background readings from regulated equipment designated as no detectable emissions initially, annually, and when requested by the Louisiana Department of Environmental Quality (LDEQ).

D. Task 4 - *Repairing Components*

- Repair all leaking components as soon as practicable, but no later than five days for first attempt at repair and 15 days for final attempt at repair.

- Monitor the repaired component to ensure the component is not leaking above the applicable leak definition.

- Place all leaking components that would require a process unit shutdown on the Delayed Repair List. Record the component ID number and an explanation of why the component cannot be repaired immediately. Also include an estimated date for repairing the equipment.

E. Task 5 - *Recordkeeping*

- Maintain a list of all ID numbers for all equipment subject to an equipment leak regulation.

- For valves designated as "unsafe to monitor", maintain a list of ID numbers and an explanation/review of conditions for the designation.

- Maintain detailed schematics, equipment design specifications (including dates and descriptions of any changes), and piping and instrumentation diagrams.
- Maintain the results of performance testing and leak detection monitoring, including leak monitoring results per the leak frequency, monitoring leak-less equipment, and non-periodic event monitoring.
- Attach ID tags to all leaking equipment.
- Maintain records of the equipment ID number, the instrument and operator ID numbers, and the date the leak was detected.
- Maintain a list of the dates of each repair attempt and an explanation of the attempted repair method.
- Maintain a list of the dates of successful repairs and include the results of monitoring test to determine the leak was repaired successfully.