# TECHNICAL EVALUATION
# &
# PRELIMINARY DETERMINATION

## APPLICANT

Renessenz, LLC
Jacksonville Facility
601 Crestwood St.
Jacksonville, Florida 32208

## PROJECT

Project No. 0310039-017-AC
Application for Air Construction Permit
Alternate Operation Mode, Boiler No. 1 Derating, and Trial run of processing imported raw material

## COUNTY

Duval

## PERMITTING AUTHORITY

Florida Department of Environmental Protection
Northeast District Office
Waste and Air Resource Management Program
8800 Baymeadows Way West, Suite 100
Jacksonville, Florida 32256

## COMPLIANCE AUTHORITY

Florida Department of Environmental Protection
Northeast District Office
Compliance Assurance
8800 Baymeadows Way West, Suite 100
Jacksonville, Florida 32256

**Revised September 6, 2013**

## 1. GENERAL PROJECT INFORMATION

### Air Pollution Regulations

Projects with the potential to emit air pollution are subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The statutes authorize the Department of Environmental Protection (Department) to establish regulations regarding air quality as part of the Florida Administrative Code (F.A.C.), which includes the following chapters: 62-4 (Permits); 62-204 (Air Pollution Control – General Provisions); 62-210 (Stationary Sources – General Requirements); 62-212 (Stationary Sources – Preconstruction Review); 62-213 (Operation Permits for Major Sources of Air Pollution); 62-296 (Stationary Sources - Emission Standards); and 62-297 (Stationary Sources – Emissions Monitoring). Specifically, air construction permits are required pursuant to Rules 62-4, 62-210 and 62-212, F.A.C.

In addition, the U. S. Environmental Protection Agency (EPA) establishes air quality regulations in Title 40 of the Code of Federal Regulations (CFR). Part 60 specifies New Source Performance Standards (NSPS) for numerous industrial activities. Part 61 specifies National Emission Standards for Hazardous Air Pollutants (NESHAP) based on specific pollutants. Part 63 specifies NESHAP based on the Maximum Achievable Control Technology (MACT) for numerous industrial categories. The Department adopts these federal regulations on a quarterly basis in Rule 62-204.800, F.A.C.

### Facility Description and Location

The applicant operates an existing Chemical Manufacturing Plant (SIC No. 2689) in Jacksonville at 601 Crestwood Street in Duval County, Florida 32201. The UTM coordinates are Zone 17, 435.6 km East, and 3360.75 km North. This site is an area that is in attainment (or designated as unclassifiable) for all pollutants subject to a National Ambient Air Quality Standard (NAAQA).

### Existing Process Description

This facility processes Crude Sulfate Turpentine, some gum turpentine, and other chemicals to produce synthetic flavor and fragrance chemicals and also chemical intermediates. Three (3) steam-generating boilers on site, which are identified as Boiler Nos. 1, 6, and 7, produce steam for process distillation columns and process reactors. Boiler No. 1 is the primary boiler with a maximum heat input of 140 MMBtu per hour. Boiler Nos. 6 and 7 respectively have maximum heat input rates of 117 and 49 MMBtu per hour. Boiler Nos. 6 and 7 are back-up boilers to be operated during transition periods, maintenance, or catastrophic failure of Boiler No. 1. Allowed fuels fired are natural gas, process derived fuel (pdf) also formerly known as Glidfuel, or No. 2 fuel oil.

### Facility Regulatory Categories

- The facility is not a major source of hazardous air pollutants (HAP).
- The facility does not operate units subject to the acid rain provisions of the Clean Air Act.
- The facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.
- The facility is a major stationary source in accordance with Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.

**Project Description Background**

During 2010 the applicant proposed a steam repowering project which included construction of Boiler No. 1 which is a circa 1996 model boiler purchased from a textile mill located in another state. The boiler was reconfigured with a new forced draft fan and new primary burner. These physical changes resulted in a derated boiler with a maximum heat input rate of 140 MMBtu per hour instead of its previous maximum rating of 180 MMBtu per hour heat input. The boiler fires natural gas, ultra low sulfur No. 2 fuel oil, and process derived fuel (PDF) formerly known as Glidfuel. The boiler operates on any single fuel or any combinations of fuel up to the maximum permitted heat input. Restrictions were placed in the permit without which PSD significant rates would have been exceeded. Reduced sulfur gases from the crude sulfate turpentine processing operation are conveyed to the boiler for incineration. Existing boiler Nos. 6 and 7 are allowed to operate on a limited basis only during the start-up, shutdown, malfunction, or maintenance of Boiler No. 1. Boiler Nos. 6 and 7 may operate simultaneously during these periods within the restricted parameters placed in the permit. During these periods, process off-gases generated by the crude sulfate turpentine processing operation shall also be combusted in Boiler Nos. 6 and/or 7. As part of the steam repowering project Boiler Nos. 4 and 5 were removed from operation at the facility as authorized by permit No. 0310039-013-AC.

**Current Project Description**

The proposed operation changes include derating the existing Boiler No. 1 (EU032), removal of the oxides of Nitrogen continuous emission monitor since the derated Boiler No. 1 will no longer be subject to 40 CFR 60, Subpart Db which requires continuous monitoring of NOx emissions, permitted flexibility including simultaneous operation of the existing three boilers, and the combustion of dimethyl sulfide (DMS) vapors by bypassing the existing distillation columns C1 and C2. It is noted that individually the three boilers are not restricted on operating hours, however emissions are limited to maintain compliance with the previous permitted requirements and yet provide operational flexibility to the facility. The proposed changes meet the definition of modifications under Rule 62-210.200(205), F.A.C., and therefore a construction permit is required to be issued prior to implementation of the proposed operation changes. This application includes a PSD permitting analysis of the proposed change to bypass the existing C1 and C2 distillation columns.

The project is not intended to regain lost capacity and will not result in any increase in the boiler(s) heat input, fuel consumption, steam generation capacity, or production capability. Pursuant to Rule 62-212.300, F.A.C., Renessenz, LLC provided information to show that the project will not exceed the significant emissions rates that require preconstruction review for the Prevention of Significant Deterioration (PSD) of Air Quality. Performance Restrictions have been placed in the permit.

**Proposed Work**

Boiler No. 1: The permittee is authorized to construct, install, modify, and operate (for purposes of testing and unit shakedown) the following equipment:

- Necessary appurtenances for the derating of Boiler No. 1 to less than 99.0 MMBtu per hour heat input which include but are not limited to replacement of the burner with a maximum heat input rating of 99.0 MMBtu per hour;
- Associated components including but not limited to piping, ductwork, connections, foundations, structures, and burner(s) of a permanent nature;

For the proposed project, the application documents the baseline actual emissions from the boiler No. 1, 6 and 7, and the projected actual emissions from the operation of Boiler Nos. 1, 6, and 7.

### Distillation Column Nos. C1 and C2 Bypass

At the present time off gas vapors from the processing of crude sulphate turpentine (column T1) are further distilled and condensed in the C1 and C2 columns. Dimethyl sulfide is one product that is manufactured during this process and is sold if a market is available. "Light" CST with most of sulfur removed is also a byproduct of this processing of the off gas vapors from column T1. It is further used at the facility. The proposed operation change will require no physical modifications to the existing boilers or distillation columns as well as ancillary process equipment at the facility. The operator will be able to simply re-route the process vapors directly to one of the existing boilers for incineration via the movement of several process valves instead of the process vapors being transferred to distillation column C1 for further processing. Because no additional process equipment will be necessary to implement this operation change, the proposed change is not considered to be a physical modification.
However the Department does consider this change to be a change in the method of operation which requires a PSD permitting applicability analysis. This proposed operation change will enable Renessenz to bypass distillation columns C1/C2 and combust the DMS process vapors directly in the boilers. This mode of operation was previously considered an alternate mode of operation which was used if a market was not available for the various products made by distillation and condensation of process vapors generated in the crude sulphate turpentine processing in column T1as described above. The proposed use of the alternate mode may result in an actual increase in SO2 emissions from the combustion of the off gas vapors in the boilers due to the sulfur content in the off gas vapors.

### Processing Schedule

| | |
|---|---|
| 05/23/2013 | Department received the application for an minor source air pollution construction permit. |
| 06/21/2013 | Department requested additional information. |
| 07/12/2013 | Department received additional information. |
| 07/12/2013 | Application complete. |
| 08/29/2013 | Department received additional information from the applicant regarding a trial run for CST processing in distillation column C5 |
| 09/4/2013 | Draft Construction Permit package issued |
| 09/5/2013 | Comments from Applicant Received |
| 09/06/2013 | Revised Draft Construction Permit package issued |

## 2. PSD APPLICABILITY

### General PSD Applicability

The Department regulates major stationary sources of air pollution in accordance with Florida's PSD preconstruction review program as defined in Rule 62-212.400, F.A.C. A PSD applicability review is required in areas currently in attainment with the state and federal AAQS or areas otherwise designated as "unclassifiable". A facility is considered a major stationary source with respect to PSD if it emits or has the potential to emit: 5 tons per year or more of lead; 250 tons per year or more of any regulated air pollutant; or 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 PSD-major facility categories (fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input, coal cleaning plants (with thermal dryers), Kraft pulp mills, portland cement plants, primary zinc smelters, iron and steel mill plants, primary aluminum ore reduction plants, primary copper smelters, municipal incinerators capable of charging more than 250 tons of refuse per day, hydrofluoric, sulfuric, and nitric acid plants, petroleum refineries,

lime plants, phosphate rock processing plants, coke oven batteries, sulfur recovery plants, carbon black plants (furnace process), primary lead smelters, fuel conversion plants, sintering plants, secondary metal production plants, chemical process plants, fossil fuel boilers (or combinations thereof) totaling more than 250 million British thermal units per hour heat input, petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels, taconite ore processing plants, glass fiber processing plants, and charcoal production plants.). Projects at existing or new major stationary sources are subject to PSD preconstruction review. In addition, proposed projects at existing minor sources are subject to PSD preconstruction review if potential emissions *from the proposed project* will exceed the PSD major stationary source thresholds.

Once a project becomes subject to PSD preconstruction review, each PSD pollutant is reviewed for PSD applicability based on emissions thresholds known as the "significant emission rates" defined in Rule 62-210.200, F.A.C. for the following pollutants: carbon monoxide (CO); nitrogen oxides ($NO_X$); sulfur dioxide ($SO_2$); particulate matter (PM); particulate matter with a mean particle diameter of 10 microns or less ($PM_{10}$); volatile organic compounds (VOC); lead (Pb); Fluorides (F); sulfuric acid mist (SAM); hydrogen sulfide ($H_2S$); total reduced sulfur (TRS), including $H_2S$; reduced sulfur compounds, including $H_2S$; municipal waste combustor organics measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans; municipal waste combustor metals measured as particulate matter; municipal waste combustor acid gases measured as $SO_2$ and hydrogen chloride (HCl); municipal solid waste landfills emissions measured as nonmethane organic compounds (NMOC); and mercury (Hg). Pollutant emissions from the project exceeding these rates are considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each such pollutant and evaluate the air quality impacts. Although a facility or project may be *major* with respect to PSD for only one regulated pollutant, it may be required to install BACT controls for several "significant" regulated pollutants.

**PSD Applicability for Project**

The derating of Boiler No. 1 will not result in an emission increase of any regulated pollutant. Emission increases are associated with the change in the method of operation of the crude sulphate turpentine (CST) processing operation. Sulfur dioxide gases are created in the boilers by the combustion of the off gas vapors created from the processing of the CST. Since the proposed changes are modifications to units which are existing, pursuant to Rule 62-212.400(2)(a)(1), F.A.C., the review procedure used to determine whether a significant emission increase would occur as a result of this project was the Baseline Actual-to-Projected Actual Applicability Test for Modifications at Existing Emissions Units. Baseline actual emissions were selected by the applicant for the 24 month consecutive period of June 2011 through May 2013.

Project pollutant increases/decreases were determined by summing the difference between the baseline actual emissions and the projected actual emissions from each boiler.

**Table A. Applicant's Projected Emission Increases (Tons per Year) and PSD Applicability**

| Pollutant | Projected Increases | PSD Significant Emissions Rate | Subject to PSD? |
|---|---|---|---|
| $SO_2$ | 28.55 | 40 | No |
| $NO_X$ | 0.00 | 40 | No |
| CO | 0.00 | 100 | No |
| PM | 0.00 | 25 | No |
| $PM_{10}$ | 0.00 | 15 | No |

| Pollutant | Projected Increases | PSD Significant Emissions Rate | Subject to PSD? |
|---|---|---|---|
| $PM_{2.5}$ | 0.00 | 10 | No |
| VOC | 0.00 | 40 | No |

Notes: Emissions calculations provided by the applicant in the application and additional information received.

## 3. FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION (FDEP) REVIEW

### Brief Discussion of Emissions and PSD Applicability

The following table presents the Departments summary of the project based upon the information presented by the applicant in the application and additional information received.

**Table B. FDEP's Annual Emissions Summary (Tons per Year) and PSD Applicability**

| Pollutant | Baseline Actual Emissions | Future Actual Emissions[1] | CHBA Emissions[2] | Project Emissions[3] | PSD Significant Emissions Rate | Subject to PSD? |
|---|---|---|---|---|---|---|
| PM | 17.29 | 22.82 | 25.65 | 0 | 25 | No |
| $PM_{10}$ | 17.29 | 22.82 | 25.65 | 0 | 15 | No |
| $PM_{2.5}$ | 17.29 | 22.82 | 25.65 | 0 | 10 | No |
| $SO_2$ | 322.04 | 506.42 | 155.83 | 28.55 | 40 | No |
| $NO_x$ | 45.31 | 59.81 | 67.24 | 0 | 40 | No |
| CO | 25.58 | 33.77 | 37.96 | 0 | 100 | No |
| VOC | 1.64 | 2.16 | 2.43 | 0 | 40 | No |

[1] Not including emissions which could have been accommodated by the existing boilers including demand growth.

[2] Including emissions which could have been accommodated by the existing boilers including demand growth.

Notes: Emissions calculations provided by the applicant in the application, additional information received, and DEP calculations.

## 3. FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION (FDEP) REVIEW

### Brief Discussion of Emissions, PSD Applicability, and Boiler Operational Flexibility

In the previously issued Permit No. 0310039-013-AC, certain boiler operating conditions were required in order to permit Boiler No. 1 so that there was not a significant net emissions increase triggering PSD review. With this project, the applicant has requested flexibility in the operation of the three boilers (Boiler No. 1, Boiler No. 6, and Boiler No. 7) at the facility. The Department has determined that with the proposed derating of Boiler No. 1to less than 99.0 MMBtu/hr, the following permit conditions remain necessary in order to provide reasonable assurance of compliance with previous permitted actions in Permit No. 0310039-013-AC, and additional permit conditions are required to insure compliance with emissions of Oxides of Nitrogen (NOx) previously required when Boiler No. 1 was subject to 40 CFR 60, Subpart Db, Standards of Performance for Industrial- Commercial-Institutional Steam Generating Units: in lieu of the use of the CEMs for determining compliance. Since the Boiler

No. 1 will be subject to 40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial- Commercial-Institutional Steam Generating Units after the derating a CEMS for NOx will no longer be required and in conjunction with the requested operational flexibility of the Boiler Nos. 6 and 7 the alternate methodology was required to insure that the permitting decisions made for permit 0310039-013-AC remained intact.

A. Processed Derived Fuel for combustion in Boiler Nos. 1, 6, and 7 shall be limited to a maximum sulfur content by weight of 0.50%. Each batch of PDF produced shall be analyzed for the sulfur content (% by weight). Applicable ASTM Methods shall be used as approved in 40 CFR 60. 17. Alternate methods may be approved in writing by the Department.

B. Liquid and gaseous fuel flow meters and recorders shall be installed, operated and maintained on each boiler (Boiler Nos. 1, 6, and 7). The meters shall be accurate to within plus or minus 5% of the normal fuel flow. The meters shall be maintained in accordance with the manufacturers' recommendations. Monthly records of the fuel flow shall be compiled, maintained at the facility, and made available to the Department upon request.

C. The PM emission factor used for compliance determinations for Boiler Nos. 1, 6, and 7 shall be 0.131 pounds per MMBtu heat input from PDF, 0.171 pounds per MMBtu heat input from fuel oil, and negligible from natural gas.

D. The Oxides of Nitrogen (NOx) emission factor used for compliance determinations for Boiler Nos. 1, 6, and 7 shall be as follows:

i. Boiler Nos. 6 and 7 -- PDF -- 0.289 pounds per MMBtu heat input

ii. Boiler Nos. 6 and 7 -- NG -- 0.265 pounds per MMBtu heat input

iii. Boiler No. 1 -- All fuels -- 0.20 pounds per MMBtu heat input

Compliance determinations are explained below in Section G. the methodology provides certainty and reduces the inherent variations built into stack testing for determining compliance over a period of a year.

## TESTING AND ANALYSIS REQUIREMENTS

Testing in E. and F. below provides assurance that the facilities meet the EF used for compliance demonstration purposes in Section G. See Section G for an explanation of the emission calculation procedures and compliance determination methods.

E. Stack Testing (Boiler No. 1). Record the quantity and type of each fuel fired during each test.

a. PM each federal fiscal year using EPA RM 5 while firing PDF. PM each federal fiscal year using EPA RM 5 while firing fuel oil (if fuel oil was combusted during the previous 12 months other than for standby purposes). Testing is for the purpose of insuring that emissions of PM are equal to or less than the Emission Factor listed above.

b. $SO_2$, upon request, using EPA RM 6 or other method approved by the Department

c. Oxides of Nitrogen (NOx) while firing PDF shall be conducted each federal fiscal year using EPA RM 7 or 7E. NOx while firing NG shall be conducted each federal fiscal year using EPA RM 7 or 7E. NOx while firing fuel oil (if fuel oil was combusted during the previous 12 months other than for standby purposes) shall be conducted each federal fiscal year using EPA RM 7 or

7E.Testing is for the purpose of insuring that emissions of NOx are equal to or less than the Emission Factor listed above.

d. CO, upon request, using EPA RM 10 or other method approved by the Department

e. VOC, upon request, using EPA RM 25 or other method approved by the Department

Within 60 days of permit issuance, the permittee shall determine the maximum heat input rate of the boiler by conducting a 24-hour full load demonstration measuring peak Btu/hr heat input after achieving steady state conditions. The Permittee shall submit a testing protocol to the Compliance Authority for approval at least 30 days prior to conducting the test. Results of the test shall be submitted to the Compliance Authority within 45 days of test completion.

F. Stack Testing (Boiler No. 6). Record the quantity and type of each fuel fired during the test.

a. PM each federal fiscal year using EPA RM 5 while firing PDF. PM each federal fiscal year using EPA RM 5 while firing fuel oil (if fuel oil was combusted during the previous 12 months other than for standby purposes). Testing is for the purpose of insuring that emissions of PM are equal to or less than the Emission Factor listed above.

b. $SO_2$, upon request, using EPA RM 6 or other method approved by the Department

c. Oxides of Nitrogen (NOx) while firing PDF (if PDF was combusted during the previous 12 months) shall be conducted on an annual basis using EPA RM 7 or 7E. NOx while firing NG shall be conducted on an annual basis using EPA RM 7 or 7E. NOx while firing fuel oil (if fuel oil was combusted during the previous 12 months other than for standby purposes) shall be conducted on an annual basis using EPA RM 7 or 7E. Testing is for the purpose of insuring that emissions of NOx are equal to or less than the Emission Factor listed above.

d. CO, upon request, using EPA RM 10 or other method approved by the Department

e. VOC, upon request, using EPA RM 25 or other method approved by the Department

G. The emission factors listed below are demonstrated factors that each of the boilers listed can meet and were used to determine emissions during the permit application review for permit 0310039-013-AC. In permit 0310039-013-AC the boiler no. 1 was the primary boiler for steam production. boiler Nos. 6 and 7 were used as back-up units during boiler downtime and/or in case of a catastrophic failure of boiler no. 1. These units were not permitted to be operational at the same time other than transitioning from one unit to the other. Decisions were based upon the potential to emit from boiler no.1. In order to provide operational flexibility to the facility an emission based approach was taken based upon the potential to emit from boiler no. 1 spread among the three boilers as determined by the permittee. The operating restrictions and method of compliance determination below provides reasonable assurance that the emissions from the new operational flexibility in this permit will not exceed the potential to emit had boiler no. 1 operated at its' full potential to emit.

A mass emission reduction (from fuel combustion of natural gas, ultra low sulfur fuel oil, and processed derived fuel) is expected from Boiler No. 1 since it will be derated to a maximum heat input capacity of 99 MMBtu per hour. In order to provide operational flexibility to the facility, simultaneous operation of Boiler Nos. 1, 6 and 7 shall be allowed subject to the following emission based conditions to insure continued compliance with previous permitted requirements established in air construction permit 0310039-013-AC:

12 Month Rolling Total
EF = Emission Factor
AF = Activity Factor

**Emission Factor**

| Pollutant | Boiler No. 1 | Boiler No. 6 | Boiler No. 7 |
|---|---|---|---|
| NOx (PDF) | 0.20 lb/MMBtu | 0.289 lb/MMBtu | 0.289 lb/MMBtu |
| NOx (NG) | 0.20 lb/MMBtu | 0.265 lb/MMBtu | 0.265 lb/MMBtu |
| NOx (Fuel Oil) | 0.20 lb/MMBtu | 0.171 lb/MMBtu | 0.171 lb/MMBtu |
| *PM (PDF) | 0.131 lb/MMBtu | 0.131 lb/MMBtu | 0.131 lb/MMBtu |
| *PM (Fuel Oil) | 0.171 lb/MMBtu | 0.171 lb/MMBtu | 0.171 lb/MMBtu |
| *PM (NG) | Negligible | Negligible | Negligible |

*$PM_{10}$ and $PM_{2.5}$ are equal to PM emissions

**Activity Factor**

MMBtu per month per fuel type per boiler

**12 Month Rolling Total, Compliance Calculation Method**

Each month the total lbs of each pollutant per boiler shall be calculated by multiplying the appropriate EF times the AF for each fuel type in each boiler. Each month's total lbs emitted shall be added to the previous 11 months total to determine the 12 month rolling total emission of each pollutant. Compliance for each pollutant (12 month rolling total) shall be demonstrated if the sum (total) emissions from all three boilers is equal to or less than the following maximum 12 month rolling total emissions:

**NOx -- 245,280 lbs per 12 month rolling total maximum

**$PM/PM_{10}/PM_{2.5}$ -- 186,314 lbs per 12 month rolling total maximum

**Equal to potential to emit from Boiler No. 1 at a rated capacity of 140 MMBtu per hour

Therefore, the project requires a minor air construction permit to authorize the Steam repowering Project. Pursuant to Rule 62-212.300(1)(e), F.A.C., the applicant shall provide reports in summarizing actual emissions ($NO_X$, $PM/PM_{10}/PM_{2.5}$, and $SO_2$) computed in accordance with the requirements of Rule 62-210.370, F.A.C. for each year during the 5-year period following completion of the project.

**NSPS Applicability**

A project for an existing unit may trigger the federal New Source Performance Standards (NSPS) in two ways.

1. The project is considered a modification when the project results in an increase in the hourly mass emissions rate of an NSPS-regulated pollutant. Since this project will not increase the performance or increase the

capacity (heat input rate, fuel consumption rate or steam generation rate) of boiler Nos. 1, 6 or 7, the hourly mass emissions rates will not increase.

2. Pursuant to 40 CFR 60.15, a project is considered reconstruction when the fixed capital costs of the replacement components exceed 50% of the fixed capital costs for a comparable new replacement unit. Minor changes in piping, meters, and other necessary appurtenances related to Boiler Nos. 1, 6 and 7 are insignificant compared to the costs of an entirely new boiler(s). Therefore, the total project costs related to boiler Nos. 1, 6 and 7 will be significantly less than 50% of the cost of a comparable replacement unit(s) and the project is not considered reconstruction for purposes of the NSPS.

3. The Derating of Boiler No. 1 to 99.0 MMBtu/hr heat input will subject the boiler to 40 CFR 60, Subpart Dc, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units and Subpart A, General Conditions as it was constructed after the applicability date of the regulation. By being less than 100 MMBtu/hr, the boiler will no longer be subject to 40 CFR 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.

## APPLICABILITY OF PREVIOUS PERMITS

Existing Permits and Regulations: The conditions of this permit supplements all other previously issued air construction and operation permits for these emission units. These conditions are in addition to all other applicable permit conditions and regulatory requirements. The Permittee shall continue to comply with the conditions of those permits, which include restrictions and standards regarding capacities, production, operation, fuels, emissions, monitoring, recordkeeping, reporting and the like.

## 4. REVISIONS TO DRAFT PERMIT PACKAGE AS A RESULT OF APPLICANT COMMENTS RECEIVED SEPTEMBER 5, 2013

On September 4, 2013, the Department issued a draft permit package for the proposed project. On September 5, 2013, the Department received comments from the applicant on the draft permit. The Department has changed the draft permit package based on the submitted comments. The comments are summarized below with the Department's response.

**1. Condition A.3 (page 8) – the authorized fuels for Boiler No. 1 (EU032) does not include process vapors. Similar to Boiler Nos. 6 and 7, the requested wording addition for this condition is – "Vapors from the vapor combustion system may also be incinerated in this emission unit."**

*Department Response: Based on the submitted comment, Condition A.3. is revised to reflect that Vapors from the vapor combustion system may also be incinerated in the No. 1 Boiler.*

**2. Condition A.8 (page 9) – typo corrections: "derated", "correlation"**

*Department Response: Based on the submitted comment, the corrections have been made to Condition A.8.*

**3. Condition A.12 (page 10) – the NSPS Subpart Dc opacity limitation (and subsequent COMS monitoring requirement) is applicable for the combustion of fuel oil in the boiler. The Georgia EPD has determined for the Renessenz Colonel's Island facility (Brunswick, GA) that the subject boilers are required to meet NSPS Subpart Dc requirements only during fuel oil combustion, and process derived fuel (PDF) is not defined as a fuel oil. Therefore, Renessenz requests that this condition specify that the COMS unit is only required to be operated when fuel oil is combusted in Boiler No. 1.**

*Department Response: Based on the submitted comment, Condition A.12. is revised as follows:*

A.12. a. The owner or operator of an affected facility subject to the opacity standard under 40 CFR 60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system.

b. All COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 of appendix B of Part 60. The span value of the opacity COMS shall be between 60 and 80 percent.

c. The operation of a continuous opacity monitoring system (COMS) as required by 40 CFR 60.47c(a) and (b), is applicable when this emissions unit combusts ULSD or mixtures of USLD with any other fuels.

[40 CFR 60. 47c(a and b), Rule 62-204.800, F.A.C., and Rule 2.201, JEPB]

**4. Boiler No. 6 (page 15) – Emission unit description does not include SIP BACT determination date. Will these be re-issued with the construction permit date and updated in the final construction permit?**

*Department Response: The BACT Determination will be re-issued with the construction permit date and updated in the final construction permit.*

**5. Boiler No. 7 (page 19) – Emission unit description does not include SIP BACT determination date. Will these be re-issued with the construction permit date and updated in the final construction permit?**

*Department Response: The BACT Determination will be re-issued with the construction permit date and updated in the final construction permit.*

**6. Section 4 (page 23) – the permit condition nomenclature currently is using "A.1" – etc, which is confusing as the Boiler No. 1 condition use the same nomenclature. Can the DEP utilize a different nomenclature such as "D.1" – etc. to avoid confusion in permit condition references for future compliance reports?**

*Department Response: Based on the submitted comment, the nomenclature in Section 4 has been changed to "D.1." etc. as requested.*

**7. Condition A.1.d.1.i (page 23) – request a cross-reference to Condition A.8 (Boiler No. 1) for NOx emission factor, which identifies NOx CEMS data (minimum of three months) for the derated boiler to be used an alternative to annual compliance testing for determining the NOx annual emissions.**

*Department Response: Based on the submitted comment, Condition A.1.d.1.i. (now renamed to Condition D.1.d.1.i.) is revised as follows:*

D.1.d. The permittee shall compute and report annual emissions in accordance with Rule 62-210.370(2), F.A.C. as provide by Appendix C of this permit. For this project, the permittee shall use the following methods in reporting the actual annual emissions for the Project 0310039-017-AC (identified as Emission Unit Nos. 032, 006, and 011):

1) Emission Unit No. 032 (Boiler No. 1)

i. The permittee shall use the procedures listed below to determine and report the actual annual emissions of $NO_X$ for the No. 1 Boiler. NOx CEMS data may be used in lieu of an annual stack test for NOx as specified within Condition A.8.

**8. Condition A.2 (page 24) – typo correction: "A.2"**

*Department Response: Based on the submitted comment, the corrections have been made to Condition A.2 (now renamed to Condition D.2.).*

**9. Condition A.5 (page 25) – typo correction: there is no Condition A.5, so the nomenclature should be updated in this section for subsequent permit conditions**

*Department Response: Based on the submitted comment, the corrections have been made to Conditions nomenclature as requested.*

## 5. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, and the conditions specified in the draft permit. No air quality modeling analysis is required because the project does not result in a significant increase in emissions. Jerry Woosley is the project specialist responsible for reviewing the application and drafting the permit. Additional details of this analysis may be obtained by contacting the project specialist at the Florida Department of Environmental Protection, Northeast District Office, Waste and Air Resource Management, 8800 Baymeadows Way West, Suite 100, Jacksonville, FL 32256, Phone: 904/256-1700.

## 6. TRIAL RUN COLUMN C5

On August 29, 2013 the applicant applied for authorization to conduct a trial run of processing imported crude sulphate turpentine in the referenced column. Based upon the information received this trial run is approved subject to the following conditions:

a. Notify the Permitting Authority of the start-up date of the trial run a minimum of three days prior to commencing the trial run and an estimate of its duration. Notify the Permitting Authority of the completion of the trial run within seven days after completion.

b. Maximum amount of imported CST processed shall be limited to 100,000 gallons. It is estimated that approximately 14.4 tons of sulfur dioxide will be generated from this trial run. However it is not expected that additional sulfur dioxide will be emitted on an annual basis because of this trial run.

   Process vapors generated by this trial run shall be captured and conveyed to one of the boilers for combustion.

d. Upon completion of the trial run submit a summary report of the trial and an estimate of the pollutant emissions generated from the trial. This report shall be submitted to the Permitting Authority within 90 days of completion.