DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION
ACTIVITY REPORT: Scheduled Inspection

B614531261

FACILITY: DTE - Electric Company GREENWOOD ENERGY CENTER		**SRN / ID:** B6145
LOCATION: 7000 KILGORE RD., AVOCA		**DISTRICT:** Southeast Michigan
CITY: AVOCA		**COUNTY:** SAINT CLAIR
CONTACT: Dave Huxhold , Environmental Engineer		**ACTIVITY DATE:** 08/07/2015
STAFF: Francis Lim	**COMPLIANCE STATUS:** Compliance	**SOURCE CLASS:** MAJOR
SUBJECT:		
RESOLVED COMPLAINTS:		

On August 7, 2015, AQD staff Francis Lim conducted a compliance inspection at Greenwood Energy Center located at 7000 Kilgore Road, Avoca, Michigan. The purpose of the inspection was to determine compliance with the Federal Clean Air Act; Article II, Part 55, Air Pollution Control of Natural Resources and Environmental Protection Act, 1994 Public Act 451; Michigan Department of Environmental Quality, Air Quality Division (MDEQ-AQD) Administrative Rules; and Renewable Operating Permit No. MI-ROP-B6145-2011.

Dave Huxhold (CP 313-530-0053) is the environmental engineer at the site.

Greenwood previously operated intermittently (at full baseload) to meet peak system load demands. Operations at Greenwood Unit 1 boiler has changed since the Unit 1 boiler now operates at low loads (50 MW) and when needed, can rapidly increase load (upon request of MISO – Midwest Independent Transmission System operator) to backfill loads when renewable energy sources like windmills stops operating.

Facility operates a primary 785-MW boiler, identified as Unit 1. The boiler can be fired with natural gas or any combination of No. 2 fuel oil, No. 6 fuel oil, and specification recycled used oil (RUO). Because natural gas is cheaper, it is now the only fuel used at Greenwood (except for ignition where fuel oil No. 2 is still used). Fuel oil No. 6 and specification used oil is not currently used. Since the site is located inland, a water pond with spray heads is used to cool the condenser water. Main boiler and its auxiliary boilers (173 MM BTU/hr each) were installed in May 1, 1972 and modified in May 31, 1999. Facility also operates three 82.4 MW peaking combustion turbines firing natural gas.

Most recent Unit 1 operations were on July 31, 2015 at 500 MW average for 2 days.

Renewable Operating Permit No. MI-ROP-B6145-2006a.
This renewable operating permit (ROP) was issued on October 1, 2011. This permit has 2 sections.

Section 1

EUBOILER1 Unit 1 boiler

The primary boiler has a maximum rated output of 785 MW using natural gas and/or fuel oil. The primary boiler can operate with up to 40% fuel oil. High sulfur and low sulfur fuel oil No. 6 is can be used as fuel oil. Fuel oil No. 2 and recycled used oil (RUO) are sometimes used – these fuel oils are blended with Fuel Oil No. 6. High sulfur fuel oil No. 6 must be used with natural gas; otherwise the SO_2 limit may be exceeded. Currently, only natural gas is the main fuel.

There are 4 fuel oil storage tanks at the site: (2) 11 million gallon fuel oil storage tanks used for Fuel Oil No. 6, (1) 1.3 million gallon fuel tank used for Fuel Oil No. 2, and (1) 375,000 gallon day tank. Recycled used oil is stored and blended with Fuel Oil No. 6. Fuel oil used to be piped in from the Marysville tank farm, except the used oil which comes in by truck. Oil delivered to the Marysville tank farm was delivered by barge. The Marysville tank farm has been dismantled. Currently, fuel oil at Greenwood is delivered by trucks.

The day tank supplies the fuel oil to Unit No. 1. Fuel oil is pumped and blended in the day tank. The blend is dependent on the sulfur content, BTU value, and market price of the fuel on that day. The day tank level is monitored by a laser-type level indicator system. Fuel oil No. 2 is pumped directly to the main boiler for ignition.

The contents of the day tank can be pumped back into the large storage tanks, if necessary. Fuel oil level is read daily during the graveyard shift. Fuel usage is tracked and recorded in the "pi system".

Since the viscosity of fuel oil No. 6 is high, the heating temperature of fuel oil No. 6 is very critical. The viscosity is sampled in line and viscosity of the oil is monitored in the control room. NOTE: Fuel oil is currently not used as fuel, except fuel oil No. 2 for ignition.

Staff obtained a copy of the Power Plant Performance Management (PPPM) form for the main boiler from August 2014 to July 2015. The PPPM gives information about the monthly fuel usage (natural gas, fuel oil No. 6, fuel oil No. 2, and recycled used oil), heating value of fuel oil, heating value of natural gas, heat input to boiler from natural gas and all fuel oil, and monthly fuel oil sulfur analysis. Sulfur analysis showed 0.001% sulfur for Fuel Oil No. 2; and 0.34 – 0.67% sulfur for fuel oil No. 6/RUO blend. Sulfur analysis is important from an operational standpoint since it determines what kind of fuel blend to burn so as not to exceed SO_2 limit.

Unit 1 is subject to the Acid Rain Program and CSAPR (Cross-State Air Pollution Rule), which requires Greenwood to participate in an emissions trading program. To determine NOx and SO_2 emissions, EPA required the installation and certification of NOx and SO_2 Continuous Emissions Monitor (CEMS). Additionally, installation and certification of a CO_2 CEMS (to determine lbs/MM BTU emissions) and flow monitor CEMS were also required. A Continuous Opacity Monitor (COMS) is installed to measure the opacity from the boiler. The ROP will not be reopened to replace CAIR permit with the CSAPR regulations. This will be done during the ROP renewal.

The CEMS and COMS are calibrated at 7 AM every morning or 4 hrs after startup. Another calibration is done 3 hrs before a scheduled shutdown. The instrument shop performs a CEMS daily inspection checklist and CEMS weekly inspection checklist. Among the parameters that a technician monitors daily are the dilution air pressure, eductor vacuum, CO_2 purge air regulator pressure, and back flush air regulator pressure. CEMS daily checklist is conducted Monday to Friday whenever the main boiler is operating. Routine monthly, quarterly, annual, bi-annual, 3-year, and 4-year maintenance checks are also conducted. A job order is generated by a maintenance program called "Maximo" for these routine maintenance activities. The annual gas RATA was done on June 3, 2014 and September 2, 2015. Flow RATA was done on August 19, 2014 (2015 flow RATA not yet done). A copy of the QA/QC program for the CEMS and COMS has been submitted to AQD and is in the plant file.

CEMS annunciator alarms are installed in the Control Room, where an operator can verify what the problem is and inform the CEMS technician or write a work order to fix the problem. CEMS technicians are on duty only on the first shift during the weekdays. In an emergency, a technician is called in during the off shifts and weekends.

CEMS are also the instruments used for determining compliance with the NSPS Subpart D limits for SO_2 and NOx. SO_2 compliance can also be verified by fuel oil sampling for sulfur content. SO_2 has a limit of 0.80 pound/MM BTU, based on a 3-hr average. NOx limit is 0.30 pound/MM BTU when fired by fuel oil and 0.20 pound/MM BTU when fired by natural gas, both based on a 3-hr average. When the boiler operates with natural gas and fuel oil, the NOx limit is prorated between 0.20 and 0.30, and is calculated corresponding to the natural gas/fuel oil ratio. The prorated NOx limit is displayed in the control room and can be verified by the operator. The CEMS can display instantaneous, 1-hr average or 3-hr average NOx and SO_2 emissions. The NOx ppm reading is converted to pounds/MM BTU using the EPA mandated equation specified in NSPS Subpart D. The system logs emissions data which alerts facility personnel of any operational issues. NOx and SO_2 trends are monitored by the CEMS. An alarm is initiated in the control room if an unusual trend of emissions that may lead to an exceedance is occurring.

NSPS subpart D requires quarterly reporting of NOx and SO_2 excess emissions based on exceedances of a three hour average, as determined from the CEMS. Additionally CAA Section 114a and the ROP requires that an SO_2 monthly emissions report (total pounds SO_2/total MM BTU) be submitted quarterly. This reported SO_2 emissions are calculated by dividing the total SO_2 emissions by the total MM BTU for the month.

Quarterly reports of SO_2 and NOx excess emissions (3-hr average) are acceptable. In the past, Greenwood reported a high percentage of NOx emissions due to "NOx data blowup" during startups and shutdowns. Using the EPA mandated equation specified in NSPS Subpart D, at low loads, startups and shutdowns, CO_2 concentration tend to be very low and therefore, NOx emissions will be calculated high. On September 11, 2012, USEPA approved Detroit Edison's request to use a diluent cap as provided in 40 CFR 75, Appendix F, paragraph 3.3.4.1. Use of diluent cap allows Detroit Edison to substitute a minimum concentration of 5% CO_2 in calculating NOx. With this approval, NOx excess emissions have gone done.

SO_2 monthly average emissions (required by CAA Section 114a and the ROP) are in compliance with the limit.

Additionally, SO_2 has a limit of 5760 pounds per hour; NOx has a limit of 2160 pounds per hour (fuel oil) and 1494 pounds per hour (natural gas); and PM has a limit of 518.4 pounds per hour. The SO_2 and NOx pounds per hour emissions were verified during the performance test. Continuous compliance with the hourly limit is verified through CEMS. PM stack test is required every three years. A PM stack test was conducted on October 1, 2013.

Unit 1 does not have a 12-month mass emission limit for SO_2 and NOx.

Rule 336.2170 requires quarterly reporting of opacity excess emissions. Quarterly reports of opacity excess emissions are acceptable.

NSPS Subpart D requires quarterly reporting of CEMS downtime and CAA Section 114a requires quarterly reporting of COMS downtime. Downtime for 2014, and the 1st and 2nd quarter of 2015 are acceptable. Note that since the Greenwood facility operates only for a few hundred hours each quarter, a few hours of monitor downtime may result in a higher percentage of monitor downtime.

Excess opacity violations are typically due to the soot blowing cycle of the main boiler. During operation, the boiler tubes may accumulate soot, which reduces the heat transfer efficiency. Steam powered soot blowers are employed to remove this accumulation. Each soot blower is a tube nearly as long as the boiler itself which cycles in and out of the combustion chamber blowing high pressure steam through the boiler coils. Now that the facility is using mostly natural gas, soot is not a problem. Even with the use of natural gas, the facility still conducts soot -blowing once a shift when the plant is operating.

Flue gas recirculation (FGR) and adjusting the damper opening in the boiler air feed ducts (to control the flow of air) are the primary means of NOx air pollution control mechanisms for the main boiler. In this technology, 20-30% of the flue gas is recirculated and mixed with combustion air. Most of the NOx formed during combustion of gas and light oil is from high temperature oxidation of atmospheric nitrogen and referred to as thermal NOx. The resulting dilution (recirculated flue gas mixed with combustion air) results in a "cooling effect" that reduces peak flame temperature and therefore reducing thermal NOx formation. The recirculated flue gas, when mixed with combustion air also lowers the average oxygen content of the air, lowering the NOx-forming reaction. Flue gas recirculation is set to manual during startup, and then changed to auto when a steady state condition is reached. Damper opening is adjusted from a signal from the forced draft fan.

Excess oxygen for combustion is kept at 2 to 3% for natural gas and 3 to 4% for fuel oil.

<u>FGBOILERS</u> Unit 1 boiler, and two auxiliary boilers

This flexible unit deals with the requirements for using RUO for Unit 1 boiler and the two auxiliary boilers at the site. Facility submitted and follows a Quality Control Program for Burning Specification Used Oil, updated January 7, 2008. Specification used oil means used oil that meets the specifications of 40 CFR 279.11 (limits arsenic, cadmium, chromium, lead, flash point, total halogens). If there is an RUO delivery, Detroit Edison takes a sample before a batch could be delivered to the site. A batch sample is analyzed to verify that it meets 40 CFR Part 279 used oil specifications.

A used oil usage permit limit was deleted for the main boiler since Detroit Edison explained that based on design capacity, the boiler is physically unable to exceed the permit limit. There is a material usage limit for recycled used oil only for the auxiliary boilers. Since the previous inspection in 2009, used oil was not used in the auxiliary boilers.

Facility has not received any specification RUO delivery since 2009.

<u>FGAUXBOILERS</u> Two auxiliary boilers

There are two auxiliary boilers (East and West) for the main boiler. The auxiliary boilers are rated at 173 MM BTU/hr each and used for startup and for heating up the plant. Only the East boiler is operated now since the

West boiler has some problems. The auxiliary boilers can be fired with Fuel Oil No. 6, No. 2 and recycled used oil, or any combination of these fuel oil.

There is a pounds per hour limit for SO_2, NOx, and PM. However, as long as the pounds/MM BTU is not exceeded, the pounds per hour limit will not be exceeded. SO_2 pounds/MM BTU emission is verified through fuel sulfur analysis. NOx compliance was verified through a stack test conducted on the East auxiliary boiler on Feb 22, 2005. Test report was received on May 13, 2005. Since the NOx emission rate was below permit limit, Detroit Edison requested, and AQD approved, that the test for the East boiler be representative so that the West boiler does not have to be tested. There are no CEMS installed in the auxiliary boilers.

Staff obtained a copy of the Power Plant Performance Management (PPPM) for the auxiliary boilers from August 2014 to July 2015. Fuel oil used is the same as fuel oil used in the main boiler.

The two auxiliary boilers are subject to the NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters (Boiler MACT 40 CFR 63, Subpart DDDDD). Compliance date for existing boilers is January 31, 2016. The East aux boiler was converted to natural gas (burner replaced in September 2014). Initial tune up was done July 9, 2014. Energy assessment has not yet been done. West aux boiler is not anticipated to operate and will be classified as limited use boiler. This boiler will not be tuned up until it is operated.

FGCOLDCLEANERS
Facility now has only one Safety Kleen cold solvent cleaner located in the maintenance department. A procedure is displayed near the cold solvent. Staff did not inspect the cold cleaner.

FGRULE290
Currently, there are no Rule 290 exempt emissions units in Section 1.

Greenwood operates an emergency diesel fire pump engine. It is an existing engine greater than 500 HP. There are no specific applicable RICE MACT requirements. It is operated for testing and operability determination.

Section 2 Natural gas fired combustion turbine generators.

FGCTGS Three natural gas-fired combustion turbine generators

The three combustion turbine generators (CTGs) are identified as EUCTG11-1, EUCTG11-2, and EUCTG12-1. The CTGs have dry low-NOx combustors and are rated at 82.4 MW each. However, depending on the outside temperature, the electrical output varies. During winter, at 100% load, electrical output of the combustion turbine is more than 82.4 MW. During the summer, at 100% load, electrical output of the combustion turbine is less than 82.4 MW.

Currently, the peakers no longer operate at 100% load all the time. Because of MISO requirements, the turbines are operated as low as 60% load. At this load, the turbines are still operated in the premix mode, which generally results in lower emissions compared to the other operating modes.

The combustion turbines are subject to the Acid Rain Program and CSAPR and operate under the same permits for Boiler 1. The facility is not required to install CEMs because the turbines are considered peakers. A PEMS was allowed in lieu of CEMs. NOx PEMS monitor the following parameters: turbine megawatts, fuel flow, exhaust temperature, compressor discharge temperature, pitch or inlet guide vanes opening (controls combustion air), and compressor discharge pressure. Part 75 appendix E requires a NOx emission rate test once every 20 calendar quarters. As required by the ROP, the NOx testing is done in conjunction with the CO testing. The CTGs were tested December 2007 and October 2012, except for CTG-11-1 which was tested in May 29, 2013 (outage in 2012 when it was tested). SO_2 PEMS is not required since natural gas is used as fuel.

For NOx PEMS, Detroit Edison chose to monitor and maintain within a given range, the following 4 parameters: pitch, compressor discharge temperature, compressor discharge pressure and exhaust temperature. Whenever one or more of the four turbine QA/QC required operating parameters is continuously exceeded for one or more successive operating periods totaling 16 unit operating hours, NOx emission rate stack test has to be redone. The parameter ranges are so broad because the parameter ranges are applicable for all ambient temperature. The parameter ranges were determined based on manufacturer's recommendation and adjusted based on operational data. The parameter ranges were obtained during the previous inspection.

A parameter range exceedance occurred in the past. On December 11, 2008, a Violation Notice was issued because one or more parameters were exceeded beyond the allowable operating time limit. Facility replied that a "warning" will now be programmed in the DAHS to alert the operator that the allowable time is nearing the 16-hour time limit.

For 2014 and up to August 6, 2015, there were no occurrences where any of the four parameters were exceeded for more than 16 consecutive operating hours for CTG 11-1, CTG 11-2, and CTG 12-1. See attached report.

Since the CTGs are acid rain sources, NOx mass emissions have to be determined. NOx emissions are calculated hourly, based on the percent load. NOx emission-heat input correlation was established during the most recent stack test. Note that NOx emission-heat input correlation varies depending on percent load. NOx emissions calculations are done through the DAHS.

The NOx calendar day limit is 9 ppmv, dry gas basis at 15% O_2, and 100% load. The CO calendar day limit is 25 ppmv, dry gas basis at 15% O_2. These limits were verified during the stack test conducted in December 2007 and October 2012.

The NOx yearly limit is 522 tons per year (for all three turbines) based on a rolling 12-month time period. The CO yearly limit is 856 tons per year (for all three turbines) based on a rolling 12-month time period. For the 12-month time period ending in June 30, 2015, yearly NOx emissions are 11.6 tons; and CO emissions are 15.1 tons.

Formaldehyde has a combined limit of 9.9 tons per year. Emission factors developed from previous formaldehyde stack test is used to calculate yearly formaldehyde emissions. For the 12-month time period ending in June 2015, yearly combined formaldehyde emissions are 0.19 ton.

PM-10 has a limit of 9.0 pounds per hour (for each turbine) and a combined limit of 102 tons per year based on a rolling 12-month time period. Emission factors developed from previous PM-10 stack test is used to calculate yearly PM-10 emissions. For the time period ending in July 2012, yearly PM-10 combined emissions are 1.5 ton. The PM-10 pounds per hour limit were verified during the performance test. PM and formaldehyde tests were conducted on Jan 15 to Jan 23, 2002. A previous PTI specified that PM and formaldehyde tests can be discontinued if test results are below 50% of limits.

A Method 9 reading is required once every 1812 hours of operation (for each turbine). A Method 9 reading was conducted on June 28, 2012 for all turbines.

Capacity factor limit for each turbine is 20% in any calendar year; and 10% averaged over the three previous calendar years. Capacity factors for 12-month periods in 2014 and 12-month period ending July, 2015 are within limits.

The total hours for startup and shutdown for each turbine shall not exceed 500 hours per 12-month rolling time period. For the 12-month period ending June 2015, startup hours are as follows: CTG 11-1, 56.76 hrs; CTG 11-2, 53.46 hrs; and CTG 12-1 48.18 hrs.

Natural gas usage combined limit is 27,300 MM cuft based on a rolling 12-month time period. For the 12-month period ending June, 2015 the combined gas usage is 863.88 MM cuft.

Attached to this activity report is a summary of the following: 12-month rolling total (ending July 2012) for fuel consumption in MMSCF; tons of NOx emissions; tons of CO emissions; tons of PM-10 emissions; tons of HCOH emissions; startup/shutdown hours for each of the turbines; calculation of the annual and triennial capacity factors for each of the turbines. Staff verified that none of the limits are exceeded.

AQD has received a copy of the Emission Minimization Plan for the turbines. The plan includes a discussion on minimizing emissions during startup/shutdown and malfunctions.

Generally, combustion tuning is not done for the CTGs. Air fuel ratio is automatically set.

NAME [signature] DATE 10-22-15 SUPERVISOR CJE