west virginia department of environmental protection

Division of Air Quality
601 57th Street, SE
Charleston, WV 25304-2345
Phone: 304 926 0475 • Fax: 304 926 0479

Earl Ray Tomblin, Governor
Randy C. Huffman, Cabinet Secretary
www.dep.wv.gov

ENGINEERING EVALUATION/FACT SHEET

B ACKGROUND INFORMATION

Application No.:	R13-2831E
Plant ID No.:	051-00130
Applicant:	Appalachia Midstream Services, LLC (AMS)
Facility Name:	Miller Compressor Station
Location:	Miller
NAICS Code:	486210
Application Type:	Modification
Received Date:	April 1, 2015
Engineer Assigned:	Edward S. Andrews, P.E.
Fee Amount:	$2,000.00
Date Received:	July 22, 2015
Complete Date:	October 19, 2015
Due Date:	January 17, 2016
Applicant Ad Date:	April 10, 2015
Newspaper:	*Moundsville Daily Echo*
UTM's:	Easting: 532.48 km Northing: 4,396.73 km Zone: 17
Description:	This action is for the replacement of four compressor engines (EPCE-1, EPCE-9, EPCE-10, EPCE-11) with Caterpillar G3516B compressor engines, account for compressor blowdown emissions, and other miscellaneous emission sources due to undated gas analysis.

PROPOSED CHANGES TO THE FACILITY

AMS proposed to make the following changes to the Miller Station:

- Remove one (1) 1,380 hp Waukesha L5794 GSI compressor engine (EPCE-1)
- Replace three (3) (1,380 hp Caterpillar G3516B compressor engines (EPCE-9, EPCE-10, and EPCE-11) with like-kind engines (EPCE-12, EPCE-13, and EPCE-14).
- Add one (1) 1,380 hp Caterpillar G3516B compressor engine (EPCE-15)

- Add compressor blowdown emissions (EP-BD)
- Add on Capstone C600 Micro turbine (EPGEN-3)
- Revise facility emissions from miscellaneous sources (EPCE-2 –EPCE 11, EPDHY-1 – EPDHY_3,

DESCRIPTION OF PROCESS

The natural gas inlet stream from surrounding area wells enters the facility through an inlet suction separator prior to the gas being compressed. After the inlet gas passes through a compressor, it goes through the dehydration process before exiting the facility. Triethylene glycol (TEG) dehydration units are used to remove water from the gas. In the dehydration process, gas passes through a contactor vessel where water is absorbed by the glycol. The "rich" glycol containing water goes to the glycol reboiler where heat is used to boil off the water. The heat is supplied by a gas-fired reboiler that exhausts to the atmosphere. Overhead still column emissions will be controlled by an air-cooled condenser. The non-condensable gases from the still column emissions overheads will be routed to the reboiler and burned by a BTEX Buster with 95% destruction efficiency. Under normal operating circumstances, flash tank overhead vapors will be routed to the reboiler to be burned as fuel with 95% destruction efficiency. Any excess flash gas vapors not burned as fuel will be routed back to the inlet of the station for reprocessing. During upset conditions, excess flash gas may be routed to the flare and combusted with 98% destruction efficiency. Upset conditions include loss of both permanent and backup power or compressor malfunction of the primary and secondary flash gas compressors.

Collected liquids are stabilized to remove volatile components before being stored in the ten (10) 400 bbl condensate storage tanks and transported off-site by truck. Overhead vapors generated in the stabilizer are compressed by an electric-driven flash gas compressor and recycled to the inlet gas stream. The hot oil heater provides hot oil to the stabilizer. Condensate dropout from liquids dumps, produced water and other pipeline fluids are stored in the two (2) 400-bbl pipeline fluids/water storage tanks and transported off-site via truck.

The generators provide electric power to the flash gas compressor, glycol pumps, hot oil pumps and other electrical equipment. Gas driven glycol pumps may also be used in place of the electric glycol pumps. The flare is used to combust gas during upsets and may also be used to combust flash tank off-gas and condensate stabilizer overhead gas as needed during flash gas compressor shutdown or maintenance. Emissions from fugitive components also occur.

SITE INSPECTION

On July 10, 2013, Mr. Steven Sobutka, engineer assigned to the Compliance and Enforcement Section of Northern Panhandle Regional Office, conducted routine inspection of the Miller Compressor Station. As a result of this inspection, Mr. Sobutka found the facility to be operating in compliance with Permit R13-2831D, which includes all applicable rules and regulations. No site inspection for this proposed application was deemed necessary.

ESTIMATE OF EMISSION BY REVIEWING ENGINEER

Emissions associated with this modification application consist of the combustion emissions from the engine replacements, revised the potential emissions from the compressor engines (EPCE-2 though 8), revised the emissions from glycol dehydration units with reboilers (EUDHY-1, EUDHY-2, EUDHY-3), one additional micro turbine, revised the emission potential from the hot oil heater (EPOH-1), revised potential emissions from equipment leaks and included blowdown emissions from compressors.

Emissions from the new engines were determined using engine manufactured emission data and the corresponding control efficiency from the oxidation catalysts manufacturer for carbon monoxide (CO), volatile organic compounds (VOCs) and formaldehyde. The engine manufacture's emissions data was used to determine the oxides of nitrogen (NO_x) emissions. The oxidation catalysts should have no effect on NO_x emissions from the engine and no control efficiency was applied for these NO_x emissions from the engines. Particulate matter (PM), which includes PM less than 10 micros (PM_{10}) and PM less than 2.5 micros ($PM_{2.5}$), were estimated from emission factors published in AP-42. The emission factor for condensable particulate matter (CPM) was included with total for each species of PM. AMS assumed a one grain of sulfur in the natural gas using in these engines and used a mass balance approach to determine sulfur dioxide (SO_2) emissions. The following table is a breakdown of potential emissions from one Caterpillar G3516B engine:

Table #1 Emissions from One Caterpillar G3516B Engine		
Pollutant	Hourly Rate (lb/hr)	Annual (tpy)
NO_x	1.52	6.66
CO	1.52	6.66
VOC	0.79	3.46
PM*	0.13	0.55
PM_{10}*	0.13	0.55
$PM_{2.5}$*	0.13	0.55
Formaldehyde	0.31	1.38
Carbon Dioxide Equivalent (CO_2e)	1,537.75	6,110.19

* Includes the condensable fraction of PM.

AMS is updating the emissions from each of the TEG dehydration units based on gas analysis on September 3, 2014. Each TEG dehydration unit is equipped with a primary electric glycol pump with a maximum capacity of 15 gallons per minute. In addition, each glycol dehydration unit has two (2) gas injection glycol pumps, each with a maximum capacity of 7.5 gallons per minute. Potential VOC emissions were based on GRI-GlyCalc results for the electric pumps since the emissions were higher than those using the backup gas pumps. Potential greenhouse gas (GHG) emissions were based on the GRI-GlyCalc results for the gas pumps since those emissions were higher than using the electric pump. Still vent vapors from the glycol dehydration units are controlled by an air-cooled condenser. Non-condensable gas from the still column overheads are routed to the reboiler and burned with 95% destruction efficiency. Under normal operating circumstances, flash tank overhead vapors are routed to the reboiler to be burned as fuel. When the heat energy requirement is satisfied for the reboiler, the excess vapors are routed to the inlet separator just upstream of the compressors for 100% control efficiency.

Table #2 – Emissions from the one dehydration						
	VOC		Benzene		Total HAPs	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Reboiler	0.01	0.02	0.01	0.01	0.01	0.01
BETX Buster	0.49	2.13	0.02	0.10	0.13	0.50
Total	0.50	2.15	0.03	0.11	0.14	0.51

The applicant determined the greenhouse gases potential of the dehydration unit which includes the contribution from combustion due to the reboiler, of 476.5 tons per year of carbon dioxide equivalent.

The applicant reviewed the emission potential from all sources at the Miller Station, which are included in the application. The following is a summary of the change to equipment and the revised emission potential on an annual basis.

Table #3 – Changes in Emissions			
Pollutant	Permit R13-2831E (tpy)	Proposed (tpy)	Net Change (tpy)
PM	8.34	8.83	0.49
NO_x	77.47	77.46	-0.01
CO	91.54	88.63	-2.91
SO_2	1.66	1.68	0.02
VOC	61.98	74.54	12.56
Total HAPs	14.85	15.15	0.30
Carbon Dioxide Equivalent	78,246.60	82,169.39	3,922.79

The main source of the increase of VOC and CO_2e emissions was that compressor blowdowns were included, which account for 65% of the VOCs and 50% CO_2e increases. EPA had changed the ratio of methane and nitrous oxide to carbon dioxide equivalences (Global Warming Potential) since the applicant last updated the emission potential for the Miller Station.

REGULATORY APPLICABLILITY

The Miller Compressor Station is a minor source with respect to the Title V Operating Permit Program (45CSR30). Thus, the facility is not required to obtain a Title V Operating Permit. The proposed changes do not affect the status with regards to 45 CSR 30.

The replacement engines are only subject to Subpart JJJJ to Part 60 and Subpart ZZZZ to Part 63. AMS proposes to install controls (oxidation catalyst) to meet the emission standard establish under Subpart JJJJJ. Because the facility is classified as an area source of HAPs, AMS satisfies the requirements of Subpart ZZZZ by complying with the requirements Subpart JJJJ. No other rules or regulations apply to the engines.

The replacement compressors are subject to a work practice requirement of Subpart OOOO to Part 60. This requires the rod packing to be replaced every 24,000 hours of operation.

The Miller Compressor Station is classified as a natural gas production facility. Under Subpart HH – National Emission Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage Facility of Part 63, the applicability of a major source in this subpart only considers the glycol dehydration unit(s) in determining if the affected source is a major source or area source of HAPs. The facility's dehydration unit is currently classified as a synthetic area source of HAPs, which means the facility has the potential to emit less than 10 tons of any single HAP and 25 tons of combined HAPs per year. Based on the HAP emission prediction with controls in Table 6, the glycol dehydration at the Miller Compressor Station will remain a synthetic area source of HAPs and is not classified as an affected source under Subpart HHH of Part 63.

AMS prepared and submitted a complete application, paid the filing fee, and published a Class I Legal ad in *Moundsville Daily Echo* on July 30, 2014, which is required under Rule 13 for a modification permit. The Miller Station remains classified as a minor source and subject to 45 CSR 22 as an "8D" source.

TOXICITY OF NON-CRITERIA REGULATED POLLUTANTS

The replacement engines and other changes will not emit any new pollutants that aren't already being emitted by another emission source at the facility. Therefore, no information about the toxicity of the hazardous air pollutants (HAPs) is presented in this evaluation.

AIR QUALITY IMPACT ANALYSIS

The writer deemed that an air dispersion modeling study or analysis was not necessary, because the proposed modification does not meet the definition of a major source as defined in 45CSR14.

MONITORING OF OPERATIONS

Subparts JJJJ and OOOO establish testing and work practice requirements for the engines and compressor based on hours of operation. The current permit (R13-2831E) requires continuous monitoring of the inlet of the catalyst and quarterly analysis of the engine exhaust for NO_x and CO. Thus, the writer does not believe any additional monitoring is required.

For the new micro turbine, fuel usage is the best indicator of compliance with emission limits, which is currently required in the current permit.

CHANGE TO PERMIT R13-2831D

Permit R13-2831D set mass emission limits and a concentration limit pre Subpart JJJJ limits for the compressor engines. The issues with having both limits is that compliance testing only verifies compliance with the concentration limits of Subpart JJJJ, which does not require exhaust flow measurements to be taken and that the mass limits are significantly lower. Using F_d factor for natural gas of Method 19 to determine flow rate, the writer converted the hourly mass rate limits into concentration levels corrected to 15% oxygen level, which matches the same requirements of Subpart JJJJ. The following table is the summary of the data used and conversion of the limits.

Table #4 – Conversion of the Mass Limit to Concentration Limits				
Pollutant	Mass Limit (lb/hr)	Exhaust Flow[2] (scfh)	Concentration Limit* based on Mass Limit (ppmvd)	NSPS Limits* (ppmvd)
Waukesha L5794 Engine				
NO_x	1.48	92,617	37.76	160
CO	1.80	92,617	75.43	540
VOC[1]	0.22	92,617	5.86	86
Caterpillar G3516B Engine				
NO_x	1.52	89,543	40.11	160
CO	1.52	89,543	65.77	540
VOC	1.10	89,543	30.29	86

1 – Assumed to be propane.
2 – Used LHV of 1026 Btu/scf of the fuel; Maximum Fuel Rate; F_d factor of 8710 dscf/MMBtu
* - Corrected to 15% Oxygen

The permit will be configured with the mass limits with the converted concentration limits as indicators to be used as means to verify compliance with the mass limits when conducting Subpart JJJJ testing. Plus, the current permit requires quarterly measurements using a portable analyzer for CO, NO, NO_2, and O_2. Comparison of the portable analyzer reading and the converted concentration limits would be another means to verify compliance. The requirements for the engines and compressor will be integrated into Section 4.0 from Section 5.0.

Section 4.0 of R13-2831D mainly had requirements that were integrated into Section 3.0 for the facility-wide such as maintain a potential for HAPs below major source levels and Section 6.0 for the use of the controls on the still vent of the dehydration units.

The requirements for the Hot Oil heater were moved to Section 8.0. Besides updating the emission limits, the PM and SO_2 limits were omitted from the Emission Limit Table. PM and SO_2 emission are generally very low from emission units burning natural gas. 45 CSR §2-11.1 excludes units with a heat input of less than 10 MMBtu/hr from the PM weight emission standard and testing/monitoring requirements. The current permit had requirements for visible emission checks (Method 22 observations) once per month. This writer recommends omitting this visible emission by setting a fuel limit restriction which defines the maximum sulfur content.

The requirements for the three dehydration units were moved from Section 7.0. to Section 6.0. Permit R13-2831D separated the emission limits from the reboiler and BTEX Buster even though the emissions are released through the same stack. The writer recommends adding the two streams into one limit with an emphasis on establishing an acceptable standard for the closed vent system, which is no detectable leaks.

Other new requirements are establishing a maximum circulation rate of glycol and maximum outlet temperature of the BTEX Condenser, which were inputs of the GLYCalc analysis that predicted the VOC and HAP emission rates.

Section 7.0 will incorporate the APCFLARE from Section 8.0 of Permit R13-2831D. The main changes to this section was updating the emission limits, establishing an annual throughput limit that coincides with the annual emission limits, and omitting non-applicable flare design specific requirements that were satisfied in the application. Permit R13-2831D required a monthly visual emission check. The writer recommends omitting it and setting verification of proper operation of the flare by conducting quarterly visible emission checks using Method 22.

Section 8 and 11 of Permit R13-2831D were combined into one section. The only change for the tank loadout is establishing a standard for the closed vent system that is used to control emissions from the storage tanks and truck loading operations. For all of the closed vent systems (dehydration units, storage tanks, loading operations), the permittee will be required to monitor the closed vent system through a leak detection and repair program (LDAR). The facility was originally constructed with a JT Skid which made the facility subject to the requirements of Subpart KKK of Part 60, which refers to LDAR requirements of Subpart VV of Part 60. Subpart VV required monitoring of closed vent systems once per year using audio-visual-olfactory (AVO) inspections methods. Since the JT skid has been removed, Subpart VV is no longer applicable. Thus, the rule citations for the LDAR will be removed and replaced with the 45 CSR §13-5.11.

RECOMMENDATION TO DIRECTOR

The information provided in the permit application indicates the proposed modification of the facility will meet all the requirements of the applicable rules and regulations when operated in accordance with the permit application. Therefore, the writer recommends granting Appalachia Midstream Services, LLC a Rule 13 modification permit for their Miller Compressor Station located near Banner, WV.

Edward S. Andrews, P.E.
Engineer

November 6, 2015
Date