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ENGINEERING EVALUATION/FACT SHEET

B ACKGROUND INFORMATION

Application No.:	R13-2914C
Plant ID No.:	017-00034
Applicant:	MarkWest Liberty Midstream & Resources LLC (MarkWest)
Facility Name:	Sherwood Gas Plant
Location:	Smithburg
NAICS Code:	211112
Application Type:	Modification
Received Date:	December 11, 2014
Engineer Assigned:	Edward S. Andrews, P.E.
Fee Amount:	$2,000.00
Date Received:	December 15, 2014
Complete Date:	July 2, 2015
Due Date:	September 30, 2015
Applicant Ad Date:	January 15, 2015
Newspaper:	*The Exponent Telegram*
UTM's:	Easting: 528.6 km Northing: 4,377.7 km Zone: 17
Description:	This action is the installation and operation of three addition extraction units and one de-ethanizer unit. This modification will include the replacement of the existing emergency flare.

DESCRIPTION OF PROCESS

MarkWest Liberty Midstream & Resources LLC (MarkWest) owns and operates the Sherwood Gas Plant which is located nearest to Smithburg, West Virginia. The Sherwood Gas Plant is a gas processing plant and compressor station to process field gas from nearby wells.

The natural gas inlet stream from surrounding area wells enters the facility through an inlet separator prior to passing through the tri-ethylene glycol (TEG) dehydration unit, which is designed to remove unwanted liquids from the gas stream. The rich TEG is routed to the reboiler where water and organic impurities are driven from the TEG as the reboiler is heated.

High pressure natural gas enters the cryogenic plant and passes through a molecular sieve to remove excess water in the gas stream. The dry natural gas will be cooled through a cryogenic plant with mechanical refrigeration, which serves to remove propane and heavier hydrocarbons in the gas stream. At this point the gas is ready for compression and will pass through one of the natural gas fired compressor engines prior to entering the downstream pipeline to a distribution or processing company. Liquids will be transported via pipeline to another facility. Liquid storage tanks at the gas plant will be pressurized with no emissions to the atmosphere under normal conditions. Storage tanks at the compressor station will be atmospheric tanks with emissions controlled with a vapor recovery unit (VRU) rated at 98% recovery efficiency. Under normal operating conditions electric pumps will be utilized to transfer the removed saltwater and hydrocarbons to another site for further processing. In emergency conditions truck loading may occur; however, the loading will be done in a closed loop system into pressurized vehicles so any emissions would be de minims. An emergency flare will be installed to burn vapors released from the reboiler, pressure relief valves in the deethanizer, and refrigeration plant in the event of an emergency.

The Sherwood Gas Plant is comprised of a number of cryogenic gas plants, each with a nameplate capacity for processing natural gas of 200 million (MM) standard cubic feet (scf) per day (d) with a maximum capacity of 230 MMscfd of natural gas. This proposed expansion project includes three addition processing plants each with the ability to process a maximum of 230 MMscfd for total of nine (9) plants with the nominal processing rate up to 1,800 MMscfd with a maximum of 2,070 MMscfd throughput for the facility. These processing plants will be identified as Sherwood VII, VIII, and IX.

These additional cryogenic gas plants will include a regenerative heater for the molecular sieve unit for each plant. Each heater will be equipped with a single burner that has a maximum design heat input rating of 18.00 MMBtu/hr.

Two additional stabilization heaters will be included as part of this project. The heaters provide process heat to stabilize the produce liquids at the facility. The heaters will have a maximum design heat input rating of 2.28 MMBtu/hr for each heater.

Due to pipeline restriction and gas customer's requirements, the outgoing gas or residue gas leaving must meet certain specifications. Currently MarkWest meets these requirements by injection of acceptable diluent gas into the outgoing natural gas. The issue with the residue gas is that the ethane content is too high which increases the heating value of the residue gas to unacceptable levels.

MarkWest proposes to install and operate a deethanizer unit at the Sherwood Gas Plant to further process the residue gas prior to exiting the facility. The deethanizer separates the ethane out of the residue gas stream using a deethanizer column. The proposed process that MarkWest plans to implement at the facility requires additional process heat.

A deethanizer heater with a maximum design heat input of 119.2 MMBtu/hr will be required for this process. The heater will be configured with eight (8) burners with each burner having a normal heat release rate of 14.9 MMBtu/hr. These burners will employ flue gas recirculation technologies with low NO_x burner designs to minimize combustion related emissions from the heat.

As part of the expansion project, MarkWest proposed to replace the existing emergency flare. The current flare (FL-991) is a pressured assisted elevated flare. This flare is used to destroy the stream that was released by pressure relief devices and purge gas. Purge gas is used to ensure that the flare header is free of oxygen at all times.

The proposed replacement flare will be an air-assisted flare to handle high flow rate releases with a non-assisted piggy-back flare for low flow releases.

SITE INSPECTION

On April 1 and 21, 2015, Mr. James Jarrett, an compliance engineer assigned to the Compliance and Enforcement Section of the agency, and the writer conducted a site visit of the Sherwood Gas Plant. Mr. Jarrett and the writer met with MarkWest' s environmental compliance personal assigned to oversee compliance of the Sherwood Gas Plant, which include Mr. Dale Gable, and other personnel assigned to the site. The main purpose of this visit was to gather information to assess the compliance status of the facility.

ESTIMATE OF EMISSION BY REVIEWING ENGINEER

Emissions associated with this application consist of the combustion emissions from the three mole sieve regeneration heaters (H-7711, H-8711, H-9711), hot oil heater (H-771), TEG dehydration unit (DH-001), TEG dehydration unit reboiler (RB-001), emergency flare (FL-991), storage tanks emissions (TNK-001), and fugitive emissions (FUG-001). The following table indicates which methodology was used in the emissions determination: The emissions change associated with this project is mainly combustion related emissions and fugitives from equipment leaks.

MarkWest used manufacturer's emission data to revise the emissions from the existing heaters and proposed new heaters except for the stabilization heaters. Most of the manufacturer's data predicted the concentration of oxides of nitrogen (NO_x), carbon monoxide (CO), and volatile organic compounds (VOCs) at 30 ppm, 50 ppm and 15 ppm respectively. The manufacturer for the hot oil heaters (H-4712, H-6712, and H-8712) had rated the NO_x concentration at 33 ppm. This manufacturer's emission data was based on 3% oxygen. The writer corrected these concentrations to 0% in accordance with Method 19. The emissions from the hot oil heaters and other pollutants for all of the heaters were estimated using emission factors published in AP-42 Chapter 1.4. The emissions for all of the heaters were based on a maximum design heat input rating with no operational limitation on use.

Table #1 – Emission from the Heaters		
Emission Unit ID#	Heater Description	MDHI (MMBTU/hr)
H-711	Mole Sieve Regeneration Heater*	7.86
H-2711	Mole Sieve Regeneration Heater*	7.86
H-3711	Mole Sieve Regeneration Heater*	7.86
H-771	Hot Oil Heater	28.25
H-4711	Mole Sieve Regeneration Heater*	18.00
H-5711	Mole Sieve Regeneration Heater*	18.00
H-6711	Mole Sieve Regeneration Heater*	18.00
H-7711	Mole Sieve Regeneration Heater*	18.00
H-8711	Mole Sieve Regeneration Heater*	18.00
H-9711	Mole Sieve Regeneration Heater*	18.00
H-6712	Hot Oil Heater	6.60
H-4712	Hot Oil Heater	6.60
H-8712	Hot Oil Heater	6.60
H-742	Stabilization Heater	2.28
H-2742	Stabilization Heater	2.28
H-3742	Stabilization Heater	2.28
D1-H-782	DeEthanizer HMO Heater*	119.2
D1-H-741	DeEthanizer Regen Heater*	14.25
Total Maximum Design Heat Input		319.92

* - Process Heater per Subpart Dc or Subpart Db and 45 CSR 2.

The applicant revised the emissions from the existing heaters based on better emissions related data for NO_x, CO, and VOCs. The manufacturer's data was available for all of the heaters except the 2.28 MMBtu/hr Stabilization Heaters, which was based on emission factors from Chapter 1.4 of AP-42. The writer reviewed the emission estimates and noticed that the manufacturer's emission concentrations were at 3% oxygen content. The applicant should have corrected the potential emissions using this data to 0% oxygen in accordance with U.S. EPA Method 19. The following table list the potential emissions from the heaters with CO, $NO_{x,}$ and VOC corrected to 0% oxygen.

Table #2 – Emission from the Heaters								
Emission Unit ID#	NO_x		CO		VOC		$PM/PM_{10}/PM_{2.5}$	
	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
H-711	0.29	1.25	0.29	1.27	0.14	0.60	0.06	0.25
H-2711	0.29	1.25	0.29	1.27	0.14	0.60	0.06	0.25
H-3711	0.29	1.25	0.29	1.27	0.14	0.60	0.06	0.25
H-771	1.03	4.50	1.04	4.56	0.49	2.16	0.21	0.91
H-4711	0.65	2.87	0.66	2.91	0.31	1.37	0.13	0.58
H-5711	0.65	2.87	0.66	2.91	0.31	1.37	0.13	0.58
H-6711	0.65	2.87	0.66	2.91	0.31	1.37	0.13	0.58
H-7711	0.65	2.87	0.66	2.91	0.31	1.37	0.13	0.58
H-8711	0.65	2.87	0.66	2.91	0.31	1.37	0.13	0.58
H-9711	0.65	2.87	0.66	2.91	0.31	1.37	0.13	0.58
H-6712	0.26	1.16	0.24	1.07	0.11	0.50	0.05	0.21
H-4712	0.26	1.16	0.24	1.07	0.11	0.50	0.05	0.21
H-8712	0.26	1.16	0.24	1.07	0.11	0.50	0.05	0.21
H-742	0.22	0.96	0.18	0.81	0.01	0.05	0.02	0.07
H-2742	0.22	0.96	0.18	0.81	0.01	0.05	0.02	0.07
H-3742	0.22	0.96	0.18	0.81	0.01	0.05	0.02	0.07
D1-H-782	4.13	18.09	4.19	18.35	1.98	8.67	0.83	3.65
D1-H-741	0.44	1.95	0.45	1.98	0.21	0.93	0.19	0.84
Total	11.81	51.87	11.77	51.80	5.32	23.43	2.4	10.47

The greenhouse gas emissions from all the heaters were totaled to be 374,462 pounds per hour and 164,084 tons per year of carbon dioxide equivalents (CO_2e). The potential greenhouse gas emissions will vary due to changes in the heating value of the residual gas burned in these emissions units. (200-EffluentHC)*(QEff)/(HCFuel)

The total HAPs from the proposed new heaters are illustrated in the following table.

Table #3 – Total HAPs from the Proposed New Heaters		
Unit #	Hourly Total HAPs (lb/hr)	Annual Total HAPs (tpy)
H-7711	0.03	0.14
H-8711	0.03	0.14
H-9711	0.03	0.14
H-8712	0.01	0.05
H-2742	0.004	0.02
H-3742	0.004	0.02
D1-H-782	0.22	0.95
D1-H-741	0.03	0.11
Total	0.358	1.57

The applicant determined the combustion related emissions from the replacement flare using emission factors published in AP-42, Chapter 1.4. MarkWest intends to only use the flare as a last resort. To ensure that the header connecting the pressured relief devices from the process units is maintained in an oxygen free environment, 11.5 scfm of purge gas, which will be residue gas, will be continuously vented through the header. There are seven pilot lights on the tip of the flare to ensure operation of the flare. Each pilot requires 1.26 scfm of gas, which equates to a total of 8.82 scfm. During non-venting operation of the flare, a total of 20.3 scfm of gas will be combusted by the flare, which equates to a heat input release rate of 1.34 MMBtu/hr.

MarkWest assumed the waste gas to be propane, which has a molecular weight of 44 lb-mole, specific volume of 8.365 ft^3 per pound, and a heating value of 2600 Btu/hr. Methane and ethane will make up a more significant portion of the gas than propane does. However, methane and ethane are not classified as VOCs under the Clean Air Act. After these two components, the next component in the highest quantity in the field gas and residue gas will be propane. Callidus, the flare manufacturer, rated the smokeless conditions from this particular flare at 200,000 pounds per hour. At this smokeless condition, the volumetric flow rate of propane would be 1,673,000 scfh.

MarkWest claimed that venting of the system would be approximately 5 minutes per event. The writer assumed 2 hours of venting at 200,000 pounds per hour per month, which equates to 40.2 MMscf per year.

The proposed flare has been designed to meet the criteria of 40 CFR 60.18. Therefore, the flare should be capable of achieving a destruction efficiency of 98% for VOC. Assuming the effluent going to the flare is 100% propane, the VOC potential from the flare is 4,000 pounds per hour and 48 tpy.

The writer used emission factors published in RG-360A/11 dated February 2012 by the Texas Commission on Environmental Quality to determine the CO and NO_x. These emissions are based on heat input from the purge gas, pilot lights and effluent, which is 4,351.14 MMBtu/hr and 1,161.133.78 MMBtu per year. At these heat inputs, the CO and NOx emissions rates are 1,198.7 pounds per hour and 600.45 pounds per hour respectively at venting conditions. The greenhouse gas potential from this flare is 570,000 pounds per hour and 7,527 tpy.

Fugitive emissions from this modification are mainly from equipment leaks. MarkWest used EPA's Protocol for Equipment Leaks Emission Estimates to predict VOC and HAPs emissions. The current facility is subject to the leak detection and repair requirements (LDAR) of Subpart OOOO and the proposed equipment will be subject to the same program. MarkWest accounted for the control effectiveness of this program when determining the equipment leak rate using EPA's protocol and the leak definition from Subpart OOOO, which refers to Subpart VVa to Part 60.

The fugitive potential of VOC emissions seems to be in question when comparing the pervious applications with this one, which is illustrated in the following table.

Table #4 Fugitive Emissions from Equipment Leaks			
Permit Application	Total No Components	VOCs (tpy)	HAPs (tpy)
R13-2914	1656	4.46	0.43
R13-2914A	3969	10.7	1.08
R13-2914B	5748	38.2	0.45
R13-2914C	9024	18.96	0.22

The following table list the number of components being monitoring under the LDAR program to include Sherwood V.

Table #5 Component List of Current Facility (not include Sherwood IV)		
Component		
Name	Code	Count
Valve	VLV	5,350*
Connector	CONN	10,750*
Pressure Relief Device	PRD	209*
Pump	PMP	31*
Compressor	COMP	11*
Total		16,351*

* - Listed in the Semi-Annual LDAR Report for 2015 filed on July 28, 2105

Using the recently reported lists of components, the writer estimated the fugitive potential of the current facility to be 27.9 tons of VOC per year and 0.33 tons of HAPs per year. MarkWest is currently permitted to install Sherwood IV which should be similar to Sherwood V. The writer used this count to project the component count for Sherwood IV and the three proposed units in the modification. The writer did not account for the deethanizer unit. The gas stream for this unit should have a VOC content of less than 1% by weight.

The estimated VOC and HAP emissions are based on the percentage of the gas or liquid stream that consists as VOCs and HAPs respectively. MarkWest has determined that the gas stream is made up of 11.48% of VOC and 0.18% of HAP. The light oil stream, which is Y grade NGL, contains 96.72% VOCs and 1.05% HAPs. The following table is the writer's estimate of potential VOC and HAPs emissions from equipment leaks from the Sherwood Gas Plant once the proposed modification has been completed.

Table #6 Projected Potential Fugitives with the Proposed Modification							
Component	Service Type	Current Component Count	Projected Count with Sherwood IV	Project Count with 3 Additional Extraction Units	TOC Emission Factor kg/hr/component	VOC Emissions (tpy)	HAP Emissions (tpy)
Connector	Gas	3428	2389	7588	1.84E-04	1.55	0.024
Flanges	Gas	2568	3347	5684	3.90E-04	2.46	0.039
Compressor Seals	Gas	11	13	19	8.80E-03	0.19	0.003
Valves	Gas	2944	3453	4980	7.09E-04	3.91	0.061
Other	Gas	209	243	345	8.80E-03	3.37	0.053
Connector	Light Oil	2850	3714	6306	1.84E-04	10.84	0.118
Flanges	Light Oil	1905	2482	4213	1.10E-04	4.33	0.079
Pump Seals	Light Oil	31	36	51	4.93E-03	2.35	0.025
Valves	Light Oil	2405	2822	4073	5.99E-04	22.79	0.247
Total		16351	18499	33259		51.79	0.649

MarkWest estimated the blowdown emissions from the compressor engines and extraction units. The blowdown from the compressors would be vented in an uncontrolled manner, which results in 1.03 tpy of VOCs and 0.049 tpy of HAPs. The extraction units would be vented to the flare. Thus, the blowdown from the units are controlled and accounted with the emissions from the flare.

The following table illustrates the previous potential emissions from the facility as permitted in R13-2914B and compared with the changes in this modification to determine the net change in permitted emissions.

Table #7 Facility Potential			
Pollutant	Permitted Emission under R13-2914B (tpy)	New Potential (tpy)	Net Change (tpy)
NO_x	77.97	118.09	40.12
CO	43.27	106.65	63.38
SO_2	0.52	0.97	0.45
$PM/PM_{10}/PM_{2.5}$	9.32	18.42	9.10
VOCs	86.05	165.95	79.90
Total HAP	15.53	18.42	2.89
CO_2e	120,736	222,950	102,214

REGULATORY APPLICABLILITY

Currently, the Sherwood Gas Extraction Plant is a non-major source under 45 CSR 14. The first step in determining applicability under PSD is to determine if the facility is major source. In determining if the facility is major one must determine if the Sherwood Gas Plant fall within any of the source categories listed in 45 CSR §14-2.43.a. The Sherwood Gas Plant does not have a combination of design heat input from fossil fuel boilers more than 250 MMBtu/hr. Heaters meeting the definition of Process Heater either in Subpart Db or Dc are not included in this total heat input for the facility. The total heat input of boilers at the Sherwood Plant is 55 MMBtu/hr. Thus, the Sherwood Gas Plant would have to have a potential to emit of any criteria pollutant at or greater than 250 tons per year (45 CSR §14-2.43.b.) to be classified as a major source.

Next step is to determine if fugitive emissions are to be included in the facility's potential to emit. The Sherwood Gas Plant does not fall within any of the source categories listed in Table 1 of 45 CSR §14-2.43.e. Therefore, only point source emissions are counted for major source applicability under PSD. The Sherwood Gas Plant does not have the potential to emit more than 250 tons per year of any single criteria pollutant and thus is not a major source under PSD. No further review is required under 45 CSR 14.

With regards to the National Ambient Air Quality Standards, Doddridge County is classified as attainment for all pollutants. Thus, no further review of this application with regards to 45 CSR 19, West Virginia Non-Attainment Permitting Rule is required.

The proposed changes in the application has the potential to exceed the modification threshold of 6 pounds per hour and 10 ton per year a CO, NO_x, and VOCs in 45 CSR 13, which requires a modification permit to install and operate these new emission units. Thus, the applicant filed a modification application, paid the filing and New Source Performance fees, and published a Class I Legal in The Exponent-Telegram on January 1, 2015.

The following discussion concerns existing applicable rules or regulations or potentially applicable rules the facility or proposed changes would be subject to:

45 CSR 2 (Rule 2); Subparts Db & Dc to Part 60 (Federal Regulations)

The existing gas plant and proposed changes calls for the use of heaters. Boilers or indirect heat exchangers are affected units under 45 CSR 2 and Subpart Db & Dc. However, a process heater that is primarily used to heat a material to initiate or promote a chemical reaction in which the materials participates as a reactant or catalyst are excluded as affected units under all three of these.

MarkWest claims that the mole sieve regeneration heaters (H-711, H-2711, H-3711, H-4711, H-5711, H-6711, H-7711, H-8711 & H-9711) and heaters for the de-ethanization unit (D1-H-782 & D1-H-741) are process heaters and are excluded from these rules and regulations.

The mole sieves use an adsorbent to dehydrate the wet gas prior to processing. Once the adsorbent is saturated with water, the mole sieve adsorbent has to be regenerated. The regeneration heaters are used to provide process heat to regenerate the adsorbent, which could be considered as a catalyst bed. Thus, these mole sieve regeneration heaters are excluded from these rules and regulations.

The purpose of the de-ethanization heater is to supply heat for the de-ethanization process which prepares purity ethane to go to market by removing it from the mixed natural gas liquid stream and removing CO2 to meet pipeline specifications. This purpose is achieved using two heated streams as described below.

One portion of the heat from the de-ethanization heater is distributed to the de-ethanization tower. The de-ethanization tower receives Y-grade liquids (this is the natural gas liquid stream from a cryogenic plant that contains liquid ethane and heavier hydrocarbons) that are trickled down through a series of trays within the tower. As heat is introduced to the tower, the ethane will vaporize and rise out the top of the tower while the remaining Y-grade flows through the bottom of the tower and is sent to storage. Heat is introduced to the tower by heating a portion of the Y-Grade stream through a heat exchanger and reinjecting it into the tower.

Another portion of the heat from the de-ethanization heater is distributed to the Amine Still. Once ethane has been recovered from the de-ethanization tower there is a percentage of CO2 that is entrained with the ethane. The CO2 must be removed to meet purity standards for ethane and to prevent freezing in the ethane pipeline. The CO2 is removed in the Amine Contactor by sending a liquid stream of proprietary 'lean' amine solution (referenced as RNH2) down through a rising stream of gaseous ethane. As the amine solution contacts the ethane the amine absorbs and forms a chemical bond with the CO2 to create a 'rich' amine solution, which is described in the following equations:

$$2RNH_2 + CO_2 \leftrightarrow RNH_3^- + RNHCOO^-$$

$$RNH_2 + CO_2 + H_2O \leftrightarrow RNH_3^- + HCO_3^-$$

$$RNH_2 + RNH_3^+ \leftrightarrow RNH_3^+ + CO_3^-$$

This 'rich' amine solution is then routed through the Amine Still where it can be regenerated, meaning the chemical reaction will be reversed thus freeing the CO2 from the chemical bond with the amine solution. The 'rich' amine solution is introduced near the top of the tower and descends through a series of trays. As heat is introduced to the 'rich' amine solution, the chemical bond is reversed and the CO2 rises out the top of the tower. The amine solution is again 'lean' and flows through the bottom of the tower to be recycled and used again in the process. Heat is introduced to the Amine Still by heating a portion of the 'lean' amine

through a heat exchanger and reinjecting it into the tower. The heated amine provides heat for the reaction and participates in the chemical reaction as a catalyst per the
the formulas listed above.

Thus, these heaters are heating a heat transfer medium that participates in a chemical reaction in the Amine Still of the De-Ethanization Unit and are not affected units under Subpart Db or Rule 2.

This leaves the hot oil and stabilization heaters for the remainder of this discussion. The hot oil heaters provide process heat by heating a heat transfer fluid that is circulated to the process stream that needs the heat energy or must be maintained to a desired temperature.

After the mole sieve, the cryogenic extraction units use phase separation to extract the natural gas liquids from the wet gas. These hot oil heaters provide process heat to regulate the temperatures in the phase separation process, which is not considered as promoting a chemical reaction. Hot Oil Heater H-771 has a maximum design heat input of 28.8 MMBtu/hr, which greater than 10 MMBtu/hr and less than 100 MMBtu/hr. This heater is subject to 45 CSR 2 and Subpart Dc. Under Subpart Dc, the only requirement for this heater is to track natural gas usage on a monthly basis. Rule 2 established an allowable PM limit and visible emission standard for this unit to achieve. 45 CSR §2-8.4.b. excludes natural gas burning units such as this heater from conducting visible emission testing (Method 9 observations) and continuous monitoring of Rule 2.

Each of the rest of the heaters (H-4712, H-6712, H-8712, H-742, H-2742, & H-3742) has a maximum design heat input of less than 10 MMBtu/hr. Thus, these heaters are only subject to the visible emission standard of Rule 2, which is a 10% opacity limit. These heaters are designed and constructed to burn natural gas and 45 CSR §2-8.4.b. excludes from the visible emission testing and monitoring of Section 8 of Rule 2. These heaters are excluded from Subparts Db and Dc due to having a maximum heat input of less than the trigger threshold of 100 MMBtu/hr for Subpart Db and 10 MMBtu/hr for Subpart Dc.

45 CSR 10 (Rule 10)

This rule establishes allowed sulfur dioxide limits for indirect heat exchangers (boilers), manufacturing process source operations, and combustion of refinery or process gas streams. The facility is basically subject to all three of the allowable standards in this rule. Rule 10 has the same definition of "process heater" as Rule 2, and Subparts Db & Dc. Thus, the heaters that meet the definition of "process heater" are not considered as fuel burning units (boilers) in this rule. However, the heaters are considered part of a manufacturing process (45 CSR §10-2.11.) because they are equipment used in connection with the process. Thus, these heaters are subject to the 2,000 ppm sulfur dioxide allowable in 45 CSR §10-4.1. MarkWest has estimated the SO_2 emissions from these heaters to be 5.34 x 10^{-4} lb of SO_2 per MMBtu, which equates to 0.37 ppmdv of SO_2 using Method 19 to back calculate the concentration of sulfur dioxide. Thus, the heaters are capable of achieving compliance with this standard without the use of any add-on control device(s).

The heaters that are not "process heater", which are heaters H-771, H-4712, H-6712, H-8712, H-742, H-2742, & H-3742, are considered as fuel burning units and are subject to 45 CSR §10-3.3.f. This provision limits the discharge of sulfur dioxide to 3.2 lb of SO_2 per MMBtu of heat input. 45 CSR §10-10.1. excludes fuel burning units that have a design heat input of less than 10 MMBtu/hr from Section 3 and Sections 6 through 8 of Rule 10. Thus, heaters H-4712, H-6712, H-8712, H-742, H-2742, & H-3742 are excluded from Rule 10. Only Heater H-771 is subject to the standard of 45 CSR §10-3.1. since it has a heat input rating of 28.8 MMBtu/hr. MarkWest has estimated the potential to emit of SO_2 emission at a rate of 5.34×10^{-4} lb SO_2 per MMBtu, which equates to less than two hundredths of one percent of the allowable. Due to the fuel restriction being limited to residual gas (natural gas), no add-on controls will be required for this unit to meet the allowable SO_2 limit of 45 CSR §10-3.1.

The two flares (FL-991 and Dehy Flare) and the reboiler for the dehydration unit are subject to 45 CSR §10-5.1. This provision prohibits the burning of any process gas stream with hydrogen sulfide content greater than 50 grains per 100 cubic feet of carrier gas. FL-991 is primarily only used as a control device for pressure relief devices in VOC service. The Dehy Flare is controlling the still vent from the dehydration unit, which is considered as a waste stream. The reboiler will be consuming gas from the flash tank (flash tank off gas) of dehydration unit, which is considered as process gas stream.

The facility typically receives wet gas with little to no hydrogen sulfide. GLYCalc was run with an input of 4 grains of hydrogen sulfide per 100 cubic feet of gas, which equates to 65 ppmvd of H_2S. GLYCalc predicted the hydrogen sulfide rate from the flash tank to be 179 ppmvd, which equates to 11 grains per 100 cubic feet of gas. During the same simulation run, GLYCalc predicted the H2S concentration at the still vent to be 352 ppmvd, which equates to 24 grains per 100 cubic feet of still vent effluent. Thus, the Dehy Flare and reboiler should meet the standard of 45 CSR §10-5.1. even if the wet gas has a H_2S loading of 4 grains per 100 cubic feet.

Effluent or purge gas going to Flare FL-991 should not contain a H2S loading greater than the incoming wet gas, which is assumed not to be greater than 4 grains per 100 cubic feet of gas. Thus, Flare FL-991 should meet the allowable limitation of 45 CSR §10-5.1. without the use of any add-on control device or further gas processing treatments.

Subpart OOOO to Part 60 (Federal Regulations)

The Sherwood Gas Plant is currently subject to several provisions of Subpart OOOO, which are listed in the following standards established in Subpart OOOO:

- §60.5385 – For Reciprocating Compressors
- §60.5390 – For Pneumatic Controllers
- §60.5400 – For Equipment Leaks at Onshore Natural Gas Processing Plant (LDAR)

- §60.5401 – Exemptions For Equipment Leaks at Onshore Natural Gas Processing Plant (Pressure Relief Devices venting to Control Device)

The proposed changes to the facility would only add additional affect units subject to these provisions §60.5390, §60.5400, and §60.5401. MarkWest plans on only installing instrument air driven pneumatic controllers, which would meet the requirements of the zero bleed rate standard of §60.5390(b)(1).

MarkWest would have to conduct the initial leak detection survey of the new process units within 180 days of initial start-up of the process unit to comply with the Leak Detection And Repair requirements of §60.5400, which is prescribed in Subpart VVa to Part 60.

Most of the pressure relief devices (PRDs) in VOC service at the Sherwood Gas Plant are vented into a closed vent system which routes any releases to Flare FL-991. MarkWest plans on venting any new pressure relief device that is needed on these new process units to Flare FL-991. §60.5400, which references to 40 CFR §60.482-4a(c), allows pressure relief device to be excluded from the LDAR requirements of §60.482-4a and §60.5401(b) if following is satisfied:

- The pressure relief device that routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device.
- The closed vent system shall be constructed of hard-piping.
    - The system shall be free of leaks, which are defined as Method 21 instrument reading of greater than 500 ppm above background.
- The flare must meet the requirements of §60.18.

The proposed flare to replace the existing FL-991 is an air assisted flare with a piggy-back flare that is a non-assisted flare. §60.18 establish criteria for air assisted and non-assisted flares which are used as control devices to meet the requirements of any regulation in 40 CFR 60. The following are the requirements for the proposed flare system:

- §60.18(c)(1) Designed and operated with no visible emissions;

- §60.18(c)(2) Operated with a flame present at all times;

- §60.18(c)(4)(ii) The exit velocity of non-assisted piggy-back flare with gas stream being combusted having a heating value of greater than 1000 Btu per standard cubic foot between 60 feet per second and 400 feet per second.

- §60.18(c)(5) The exit velocity of the air assisted shall not exceed V_{max} as determined in §60.18(f)(6), which is 253.5 feet per second;

- §60.18(c)(3)(ii) & (c)(4)(ii) The effluent going to the flare system shall have a heat content greater than 1,000 Btu per cubic foot.

The proposed flare system to replace Flare FL-991 will meet that above criteria. Thus, the pressure relief devices can be excluded from the LDAR of §60.482-4a and §60.5401(b). To meet the closed vent system requirement of §60.482-10a, MarkWest shall implement the LDAR requirements of §§60.482-10a(f) & (g),which an initial inspection of the closed vent system and annual inspection thereafter.

MarkWest believes there is some PRDs at the facility that vent straight to atmosphere. Subpart OOOO requires monitoring of PRDs in VOC service quarterly and within 5 days of a pressurized release unless the facility is a non-fractionation plant that uses non-plant personnel to conduct leak monitoring. PRDs at non-fractionation facilities after a pressurized release are required to be monitored at the next schedule but not to remain in service for a period of greater than 30 days without being monitored (40 CFR §60.5401(4)). The Sherwood Plant is a non-fractionating plant and currently uses a third party contractor to conduct the leak surveys at the facility. Thus, the exception in §60.5401(4) would be applicable to the PRDs at the Sherwood Plant.

45 CSR 30 – Requirements For Operating Permit

The only additional regulation this proposed modification triggers is that the facility will be classified as a major source under 45 CSR 30 – Operating Permit Program. The installation of the replacement flare (FL-991) and corrected component count of equipment leaks will make the Sherwood Gas Plant major for VOCs. After completion of the entire modification, the facility will be major under Rule 30 for $NO_{x,}$ and CO as well. The applicant will be required to submit a Title V Permit Application within 12 months after startup of the replacement flare.

TOXICITY OF NON-CRITERIA REGULATED POLLUTANTS

There will be small amounts of various non-criteria regulated pollutants emitted from the combustion of natural gas. However, due to the small concentrations emitted, detailed toxicological information is not included in this evaluation. The modification will only increase the HAP emissions by less than 3 tpy of which 1.36 tons is n-hexane. The facility will still be classified as an area-source of HAPs with a potential to emit of total HAP of less than 19 tons per year.

AIR QUALITY IMPACT ANALYSIS

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

MONITORING OF OPERATIONS

The main source of emissions from the proposed new processing units (Sherwood VII, VIII, and IX) will be equipment leaks. Under Subpart OOOO, MarkWest is required to implement a Leak Detection and Repair as outline in Subpart VVa. 40 CFR §60.482-1a(a) requires MarkWest to demonstrate compliance within 180 days of initial startup of the new processing units, which would be Sherwood VII, VIII, & IX and two stabilization units.

Subpart VVa outlines the follow-up frequency of monitoring for equipment using Method 21. However, MarkWest has elected to use the alternative work practice method as prescribed in 40 CFR §§60.18(g) through (i), which uses optical gas imaging instrument (OGII) in lieu of Method 21. Based on the detection sensitivity of the selected instrument and Table 1 to A of Part 60 – Detection Sensitivity Levels, MarkWest has chosen bi-monthly monitoring frequency of conducting leak survey at the Sherwood Gas Plant. The alternative work practice standard requires that Method 21 would be used in lieu of the OGII once per year for one of the bi-monthly monitoring surveys.

While using this alternative work practice method, the following are not applicable for the equipment being monitoring, which would be allowed under Subpart VVa using Method 21:

- Skip period detection and repair;
- Quality improvement Plans; or
- Complying with standards for allowable percentage of valves and pumps to leaks.

The De-ethanization unit should not be in VOC service because residual gas will contain less than 10% VOCs (40 CFR §60.5400(f)). Methane and ethane are excluded as VOCs in the Clean Air Act. These two compounds accounts for over 90% of residual gas going to the unit. The permit will required MarkWest to maintain documentation indicating that the de-ethanization unit is not in VOC service, which are required by 40 CFR §§60.486a(i) & (j), & §60.5400(f).

The other main focus is monitoring the residual gas (fuel gas) that is combusted in the heaters at the facility and conducting tune-up of the burner for these heaters. MarkWest uses a small percentage of residual gas, which is natural gas going to be introduced into a pipeline system, fuel for the heaters at the facility. This residual gas is not technically pipeline quality because it has not been introduce to a pipeline system. MarkWest currently analyze the residual gas to determinate basis properties and molar content of the components once per month and hydrogen sulfide once per year. Typically the VOC content of the residual gas is less than 1% by weight and incoming gas has a contractual requirement not to exceed 4 grains of H_2S.

The writer recommends using these parameters to establish a fuel quality for the residual gas. Because this residual gas is used in the compressor engines, heaters, and purge gas for FL-991, these residual gas requirements should be in Section 3.0 Facility-Wide Requirement of the permit.

The design heat input of the heater as a result of this modification has increased by 164%. To minimize emissions of CO and NO_x, MarkWest has selected Low-NO_x Burners with flue gas recirculation (FGR) technologies on the heaters that are feasible to do so. The writer recommends requiring tune-up once every 3 years for heaters over 5 MMBtu/hr to optimize NO_x emissions while minimizing the formation of CO based on the manufacturer's guaranteed concentrations.

All of these heaters are gas fired units. So, monitoring visible emissions from these units is not a valuable indicator of compliance with these gas fired units. Thus, the writer recommends omitting the visible emission testing requirements and replaces it with tracking fuel usage and heat input towards an annual emission for NOx, CO, and VOCs.

Monitoring of the new flare is tracking the amount of effluent sent to the flare, visible emissions and that either the flare or pilot light is lit.

CHANGE TO PERMIT R13-2914B

The changes between the Permit R13-2914B and the proposed draft permit were focused on the following points:

- Organization – Permit R13-2914C was revised to establish sections by equipment rather than by rule.
- Missing control device.

The writer recommends establishing specific sections by emission unit types (engines/compressors, dehydration unit, heaters, tanks & loading operations, LDAR). This approach linked several existing sections into one. Such as the engines/compressors are combined into Section 4.0 which included Sections 5.0, 10,0 and part of 12.0, while omitting Section 11.0 (Rice MACT) totally. The engines are subject to the NSPS Subpart JJJJ and the compressors that are connected to these engines are subject to the rod packing requirement of Subpart OOOO. These engines are subject Subpart JJJJ which satisfies the requirements of the Rice MACT (40 CFR §63.6590(c)). The engines are oxidation catalyst controlled and are tested every 8,760 hours service or once every 3 years. The writer recommends omitting the tracking fuel usage for these engines. Hours of operation, which required by Subpart JJJJ and OOOO, is used to determine when emissions testing is to be conducted and maintained to be performed (rod packing replaced, air/fuel ratio controller).

The dehydration unit is covered under Sections 7.0, 8.0, and parts of 12.0. in Permit R13-2914B. It should be noted that the control device for the actual dehydration unit is not FL-991 and was not included in any of the previous applications filed with the agency. The dehydration unit has its own enclosed combustion device. The VOC and HAP limits in Section 7.0 of Permit R13-2914B were combined with Section 7.0 into Section 5.0. in R13-2914C. Non-applicable portions of were omitted that pertain to design type of the control device (i.e. steam-assisted flare). The applicable provisions of Subpart HH, which covered how to determine the annual average natural gas throughput and determining actual average benzene emissions, were inserted. The flare assessment was replaced with conducting 2 hour visual observation test and 1 hour quarterly check to ensure the control device is operating properly. The reboiler is fueled by the gas from the flash tank, which is subject to 45 CSR §10-5.1., which is included as well. Subpart OOOO requires the LDAR program to include leaks from the dehydration unit and close vent systems to control devices. The requirements from Subpart OOOO will remain in a separate section (Section 8.0) in the modified permit.

The changes to the requirement for the heaters were discussed in the Monitoring Section of this evaluation.

Section 9.0 in Permit R13-2914 covers the storage tanks at the facility. This section only required the vapor recovery unit (VRU) installed and operated with a control efficiency of 98% for VOCs. The potential to emit of VOCs with the VRU is less than 6 tpy for each tank. Subpart OOOO sets requirements for VRUs that are used to control VOC emissions from storage tanks less than the trigger level, which are cover requirements (§60.5411(b)) and closed vent system requirements (§60.5411(c)). These requirements were included in Section 7.0 in the modified permit. The writer recommends establishing a VOC emission limit for the storage tanks and required compliance for the 98% based on operating hours of the VRU compressor divided by the hours the tanks are in service over a 12-month rolling period. Additional requirements for the system is monitoring when the by-pass device for the VRU system is used. These requirements are in Section 7.0 of the draft permit. LDAR program requirements for the closed vent system are in Section 8 in the draft.

The writer established one section in the draft permit (Section 8.0) to cover the gas processing units and LDAR program for the facility. Permit R13-2914B has establish Section 7.0 to cover Flare FL-991and Section 12.0 for the LDAR of Subpart OOOO. Conditions 4.1.5. through 4.1.7. established maximum wet gas throughput, number of components limits for the whole facility and a generalized LDAR requirement. The writer believes these requirements are no longer sufficient. The purpose of the LDAR requirements of Subpart OOOO is to reduce VOC emissions from equipment leaks at natural gas processing plants. These are applicable regardless of the number of components or amount of gas processed. Second, 40 CFR §60.5365(f)(2) defines that all associated equipment with the gas processing at gas processing plants as affect units subject to the LDAR requirements of Subpart OOOO, which includes dehydration units compressor stations and field gas gathering system. Also, Subpart OOOO notes that the equipment in wet gas service or makes contact with a process system that contains 10% or more of VOCs is subject to the LDAR requirements. Thus, the generalized LDAR is really only covering equipment after the extraction process. The writer recommends having Section 8.0 focus on the applicable LDAR requirements of Subpart OOOO which refers to the LDAR of Subpart VVa. This LDAR program does cover process units PRDs that vent to a control device. Thus, the writer recommends including the closed vent system that the PRDs vent to which is routed to Flare FL-991, which includes Flare FL-991 itself.

RECOMMENDATION TO DIRECTOR

The information provided in the permit application indicates the proposed changes of the facility will meet all the requirements of the application rules and regulations when operated in accordance with the permit application. Therefore, the writer recommends granting MarkWest Liberty Midstream & Resources LLC a Rule 13 a modification permit for the proposal expansion at the Sherwood Gas Extraction Plant located near West Union, WV.

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Engineer

September 11, 2015
Date