11/25/14

Id. No. ____________ Reg. ________

Company ____________

Facility ____________ Region 1

Initials John Legg

To: File
From: John Legg
Date: 11/25/14

John Legg 11/25/14

Subj: R13-3135A (Class II Administrative Update)
Chevron, Carmichael Natural Gas Production Site
190 Route 250, Cameron, Marshall County, WV
Permit Application R13-3135A; Plant ID No. 051-00179

NON-CONFIDENTIAL ENTIRE DOCUMENT

Summary

Based on a forecasted increase in natural gas production for the above facility, this update will:

- allow produced water throughput to the Produced Water Tank (ABJ-0011) to increase to 183,960 gallons per year (from 122,640 gallons per year).

- allow an increase in the number of tank truck trips required to unload the increased amount of produced water. This will result in slight increases in VOC emissions from the loading rack (LR-1) and in fugitive PM emissions from haulroads (which are not process emissions and are not limited in the permit).

- add an additional mode of operation to the Condensate Tank (ABJ-0014), previously known as the Blowdown Tank, to include the loading of produced water. Throughput to the Condensate Tank (ABJ0-00014) will be increased to 151,200 gallons per year (from 630 gallons per year).

Because of the forecasted increase in natural gas production and the resulting increase in produced water, criteria pollutant emissions for the facility are expected to increase by the following amounts: 1.49 ton/yr (tpy) VOC; 0.02 tpy HAPs; and 0.00 tpy PM (fugitive haulroad emissions).

This update also re-calculates greenhouse gas emissions based on the January 2014 changes in the global warming potentials of methane and nitrous oxide. The calculated increase in greenhouse gases (of 209 tpy) is not reflected/shown in the updated permit because CO_2e emissions are not limited in the permit.

Facility Description

There were no proposed change(s) to the process at the Carmichael Natural Gas Production Site other than increased produced water and condensate flows. The following process description is provided for the reader's information:

The Carmichael Natural Gas Production Facility operates in Marshall County, West Virginia. A process flow diagram was provided in the application in Attachment F. Natural gas and liquids are extracted from underground deposits and pass through separation equipment designed to extract the natural gas from the produced water and condensate. The natural gas is transported from the well to a gas sales line, and produced water and condensate will be stored temporarily on-site in storage vessels. Produced water and condensate are removed from the site by tank trucks on an as needed basis.

No new equipment was installed for this update, i.e., the same equipment permitted under R13-3135 is permitted under updated permit R13-3135A.

Emission Units Table (Attachment I in application)						
Emission Unit ID	**Emission Point ID**	**Emission Unit Description**	**Year Installed/ Modified**	**Design Capacity**	**Type and Date of Equipment Change**	**Control Device**
BAP-0110	BAP-0110	Line Heater (1)	2013	1.0 MM Btu/hr	No Change	NA
MBF-0111	NA	Ethanol Based De-Salter (3)	2013	0.70 ft^3	No Change	NA
MBF-0110	NA	Fuel Gas Pot (4)	2013	0.70 ft^3	No Change	NA
MBD-0120	NA	Three-phase Gas Separator (2)	2013	36 ft^3	No Change	NA
MBF-0030	NA	Fuel Gas Scrubber (3)	2013	1.75 MM scfd	No Change	NA
ABJ-0014	ZZZ-0060	Condensate Tank*(2)(5)(6)	2013	400 bbls	No Change	ZZZ-0060
ABJ-0011	ZZZ-0060	Produced Water Tank*(3)(5)(6)	2013	400 bbls	No Change	ZZZ-0060
ABF-0065	NA	Knockout Drum (5)	2013	5.6 ft^3	No Change	NA
ZZZ-0060	ZZZ-0060	Enclosed Ground Flare* (3) (Vapor Destruction Unit)	2013	4.4 MM Btu	No Change	NA
LR-1	LR-1	Liquids Loading Rack* (6)	2013	5,040 gal/day	No Change	NA

* Units marked with an asterisk (*) are involved in this update.

(1) Raw gas is routed through a line heater (BAP-011). The line heater assists with the phase separation process in the downstream three-phase Gas Separator (MBD-0120), especially during cooler ambient temperatures.

(2) In the three-phase Gas Separator (MBD-0120): A produced water stream (new) and condensate mix stream are removed from the raw natural gas. The produced water stream is send to the produced water storage tank (ABJ-0011). The condensate mix stream is sent to the Condensate Tank (ABJ-0014). A natural gas stream from the gas separator (MBD-0120) is routed to the fuel gas scrubber (MBF-0030) and the ethanol based de-salter (MBF-011). The main natural gas stream from the gas separator (MBD-0120) is routed to the downstream sales pipeline.

(3) In the Fuel Gas Scrubber (MBF-0030), natural gas either flows to the vapor destruction unit (ZZZ-0060) where it is burned, or to the ethanol based de-salter (MBP-0111) through to the Fuel Gas Pot (MBF-0110) and then to the line heater (BAP-0110), where it is burned as a fuel source. Produced water goes to the Produced Water Tank (ADJ-0011).

(4) Produced water is removed in the ethanol based de-salter (MBP-0111), fuel gas pot (MBP-0110) and the fuel gas scrubber (MBF-0030) and sent to the produced water storage tank (ABJ-0011).

(5) Emissions from the produced water tank (ABJ-0011) and the test tank (ABJ-0014), formerly the blowdown tank, are directed to the knockout drum (ABF-0065) and then to the vapor destruction unit (ZZZ-0060) where they are incinerated.

(6) Produced water from the produced water storage tank (ABJ-0011) and condensate from the condensate storage tank (ABJ-0014) are pumped into tank trucks on an as needed basis and disposed of off-site.

Time Line/Important Dates

August 25, 2014 - The Division of Air Quality (DAQ) received this Class II Administrative Update from Chevron Appalachia, LLC (Chevron) for the Carmichael Natural Gas Production Site.

August 26, 2014 - The $300.00 application fee was paid and the writer was assigned to review the application.

October 16, 2014 - Chevron revised/corrected application pages.

October 17, 2014 - Chevron's legal advertisement runs in **The Moundsville Daily Echo**.

October 29, 2014 - The DAQ received the original affidavit of publication for Chevron's legal advertisement. The application deemed complete.

November 17, 2014 - Public comment period ends.

Citizen Response to Company's Legal Advertisement

There were no public comments in response to Chevron's legal advertisement.

Application Change(s)

The following application changes related to the Produced Water Tank (ABJ-0011) and the Test Tank (ABJ-0014) are noted here for informational purposes:

Changes in Tank Information (Attachment L in application) because of this Update (R13-3135A)					
Item	**Units**	**Produced Water Tank (ABJ-0011)**		**Condensate Tank (Blowdown Tank) (ABJ-0014)**	
		Before Update	**After Update**	**Before Update**	**After Update**
Tank Internal Diameter	Ft	15	15	15	12
Maximum Liquid Height	Ft	19.5	19.5	19.5	19.5
Maximum Vapor Space Height	Ft	19.5	19.5	19.5	19.5
Maximum Annual Throughput	gal/yr	306,600[(1)]	183,960	630	151,200
Maximum Daily Throughput	gal/day	840	504	210	414
Number of Turnovers per Year	Count	19	11	1	9
Maximum Tank Fill Rate	gal/min	0.58	0.35	14	0.29
Liquid Density	lb/gal	8.22	8.22	5.32	5.32
Liquid Molecular Weight	lb/lb-mole	21.19	21.19	82.37	82.37
Vapor Molecular Weight	lb/lb-mole	21.19	21.19	82.37	87.37
(1) The permitted value (R13-3135 issued March 4, 2014) was for only 122,640 gal/hr, not the 306,600 gal/hr flow rate given in the permit application.					

Changes in Control Device Information (Attachment M in application) because of this Update (R13-3135A)				
Item		**Units**	**Vapor Combustion Unit (ZZZ-0060)**	
			Before Update	**After Update**
Characteristics of the Waste Gas Stream to be Burned	VOCs	lb/hr	1.20	17.10
	HAPs	lb/hr	0.04	0.17
	CH_4	lb/hr	0.08	0.96
	CO_2	lb/hr	<0.001	0.009
Total Combustible to Flare (Max. mass flow rate of waste gas)		lb/hr	1.32	18.24

Proposed Emission Increases

Emissions from the facility consist of combustion emissions from the line heater (BAP-011) and the vapor destruction device (ZZZ-0060), and VOC and HAP emissions from the liquid loading rack (LR-1).

Emissions from the Produced Water Storage Tank (ABJ-0011) and the Condensate Tank (ABJ-0014) are controlled in the vapor destruction device (ZZZ-0060) which has a 98% VOC/HAP destruction efficiency.

Fugitive emissions from haul roads (PM), equipment leaks (VOC/HAP), and pneumatic controllers (VOC/HAP) are calculated but not limited in the R13 permit.

The following table indicates which methodology was used in the emissions determination:

Emission Unit ID #	Process Equipment	Calculation Methodology
BAP-0110	Line Heater (1.0 MM Btu/hr)	EPA AP-42 Emission Factors - Chapter 1.4 "NG Combustion"
ABJ-0011	Produced Water Storage (400 bbl; 16,800 gal)	Promax Process Simulation
ABJ-0014	Test Tank Storage (400 bbl; 16,800 gal)	Promax Process Simulation
ZZZ-0060	Vapor Destruction Device (4.4 MM Btu/hr)	- AP-42, Chapter 1.4, July 1998 - 40CFR98 Subpart W, Equation 19, 20, and 21
LR-1	Liquid Loading Rack (5,040 gal/day)	Promax Process Simulation

The following potential increases in process emissions were listed in Chevron's October 17, 2014 legal advertisement and are calculated in Chevron's R13-3135A permit application:

Pollutant	Advertised Delta Increase Resulting from Update/R13-3135A (ton/yr)	Old Facility Wide Potential-to-emit (PTE) from R13-3135 (ton/yr)	(2) New Facility Wide PTE After Update (Update Increase + Old PTE)
* Volatile Organic Compounds (VOC)	1.49	0.14	1.63
* Hazardous Air Pollutants (HAPs)	0.02	0.013	0.034
(1) Particulate Matter (PM)	0.00	0.032	0.032
Carbon Dioxide Equivalencies (CO_2e)	208.54	563.19	771.73
Nitrogen Oxides (NOx)	0.00	0.43	No Change
Carbon Monoxide (CO)	0.00	0.38	No Change
Sulfur Dioxide	0.00	0.01	No Change

* After controls/vapor destruction device having a 98% destruction efficiency.
(1) PM process emissions did not increase. See fugitive road dust emissions below.
(2) Doesn't include haul road, fugitive, and pneumatic devices emissions.

Increase/Delta in Process Emissions Resulting from Update R13-3135A						
Emission Source	VOCs		HAPs		CO_2e	
	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)
BAP-0110	0.00	0.00	0.00	0.00	0.00	0.00
ZZZ-0060	0.32	1.39	0.002	0.01	47.56	207.29
LR-1	0.06	0.10	0.00	0.005	1.20	1.25
Total Increase	0.38	1.49	0.002	0.02	48.76	208.54

Increase in Haulroad (Fugitive) Emissions Resulting from Update R13-3137A	
Emission Source	**PM (ton/yr)**
Haul Roads	0.00*
* Advertised in Newspaper. Emissions are not a process emissions increase.	

Process Equipment Changes

No new equipment pieces were installed under this update. Piping changes made because of this update were discussed above under the **Facility Description** section.

Material Safety Data Sheets (MSDS)

No new chemicals were used because of this update. Therefore, no new MSDS were included with this update. The application for permit R13-3145 contained one MSDS from Natural Gas – Sweet.

Aggregation Analysis

Aggregation was discussed extensively in the engineering evaluation and application for Permit R13-3135. This update does not alter that discussion.

For additional information on aggregation analysis, please consult the sources referenced in the first paragraph of this section. See Attachment 1 at the end of this evaluation for a hard copy of this information.

Regulatory Discussion

Chevron provided a regulatory discussion in Attachment D to their update application. There have been no regulatory changes since last time. This discussion is presented below for the reader's information:

45 CSR 2 "Particulate Air Pollution from Combustion of Fuel in Indirect Heat Exchangers"

The purpose of 45 CSR 2 is to establish emission limits for smoke and particulate matter which are discharged from fuel burning units.

Rule 2 states that any fuel burning unit that has a heat input under 10 mm Btu/hr is exempt from Section 4 (Weight Emission Standard), Section 5 (Control of Fugitive Particulate Matter), Section 6 (Registration), Section 8, (Testing, Monitoring, Recordkeeping, and Reporting) and Section 9 (Startups, Shutdowns, Malfunctions). However, failure to attain acceptable air quality in parts of some urban areas may require the mandatory control of these sources at a later date.

The line heater is an indirect heat exchanger fired on natural gas but is exempt from Rule 2 based on its heat input capacity being less than 10 mm Btu/hr. However, Chevron is subject to Rule 2's 10% opacity requirement based on a six minute block average.

45 CSR 6 "To Prevent and Control Air Pollution from the Combustion of Refuse"

The purpose of this rule is to prevent and control air pollution from combustion of refuse.

The enclosed ground flare/vapor destruction unit is subject to Rule 2, Section 4, "Emission Standards for Incinerators." Compliance is demonstrated by maintaining records of the amount of natural gas consumed by the flare and the hours of flare operation. The facility is also required to monitor the flare's flame and record any malfunctions that may cause flame to go out during operation.

45 CSR 10 "To Prevent and Control Air Pollution from the Emissions of Sulfur Oxides"

Rule 10 states that any fuel burning unit that has a heat input under 10 mm Btu/hr is exempt from Section 3 (Weight Emission Standard), Section 6 (Registration), Section 7 (Permits), and Section 8 (Testing, Monitoring, Recordkeeping, Reporting). However, failure to attain acceptable air quality in parts of some urban areas may require the mandatory control of these sources at a later date.

The line heater is an indirect heat exchanger fired on natural gas but is exempt based on its heat input capacity being less than 10 mm Btu/hr.

45 CSR 13 "Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Administrative Updates, Temporary Permits, General Permits, Permission to Commence Construction, and Procedures for Evaluation"

Chevron's facility is a stationary source under Rule 13, Section 2.24.a, because it is subject to 45 CSR 6 which is considered to be a substantive requirement of an emission control rule promulgated by the Secretary.

The facility currently operates under R13-3135. This update meets the requirements for a Class II Administrate Update. Chevron submitted an application, published a Class I legal advertisement to notify the public, and paid the appropriate application fee.

45 CSR 14 "Permits for Construction and Major Modification of Major Stationary source of Air Pollutants"

Chevrons Carmichael site is not a major stationary source, i.e., emissions of CO, NOx, SO_2, $PM_{2.5}$, and VOC are below 250 tpy per each of the criteria pollutants listed.

45 CSR 16 "Standards of Performance for New Stationary Sources"

This rule establishes and adopts standards of performance for new stationary sources promulgated by the United States Environmental Protection Agency pursuant to section 111(b) of the federal Clean Air Act, as amended. This rule codifies general procedures and criteria to implement the standards of performance for new stationary sources set forth in 40 CFR Part 60. The Secretary hereby adopts these standards by reference. The Secretary also adopts associated reference methods, performance specifications and other test methods which are appended to these standards.

40 CFR 60, Subpart OOOO Standard of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution

See the engineering evaluation for R13-3135 for greater detail on 40CFR60, Subpart OOOO.

Published in Federal Register on August 16, 2012. Establishes emission standards and compliance schedules for the control of VOC and SO_2 emissions from affected facilities that commence construction, modification or reconstruction after August 23, 2011.

Subpart OOOO is applicable to natural gas production operations, i.e., Chevron's Carmichael Natural Gas Production facility.

Affected Sources:

a) Carmichael's hydraulically fractured gas well is an affected facilities under this subpart.

b) There are no centrifugal compressors at the Carmichael Site.

c) There is no reciprocation compressors at the Carmichael Site. Therefore, all requirements regarding reciprocating compressors under 40 CFR 60 Subpart OOOO would not apply.

d) There are no continuous bleed gas-driven pneumatic controllers at Carmichael Site. The gas-driven pneumatic controllers are either intermittent bleed or continuous low bleed devices with a bleed rate of less than 6 scfh.

e) The storage vessels located at the Carmichael Site are controlled by an enclosed combustion device and emit less than 6 tpy of VOC. Therefore, Chevron is not required to further reduce VOC emission by 95%.

f) The group of all equipment, except compressors, within a process unit is an affected facility. The Carmichael Site is not a natural gas processing plant. Therefore, Leak Detecton and Repair (LDAR) requirements for on shore natural gas processing plants would not apply.

g) There are no sweetening units at the Carmichael Site.

The following rules do not apply to the facility:

40CFR60
Subpart 60.18 "General Control Device and Work Practice Requirements"

This subpart refers to flares but makes no mention of vapor combustors, which are essentially enclosed combustion devices. Therefore, Chevron is not subject to this standard.

40CFR60
Subpart Kb "Standards of Performance for VOC Liquid Storage Vessels"

This subpart does not apply to storage vessels with a capacity less than 75 cubic meters. The tanks that Chevron has installed are 63.60 cubic meters each and therefore, are not subject to this subpart.

40CFR60
Subpart KKK "Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants"

This subpart applies to onshore natural gas processing plants that commenced construction after January 20, 1984, and on or before

August 23, 2011. The Carmichael Site was constructed after August 23, 2011 and is not a natural gas processing plant, therefore Chevron is not subject to this subpart.

40CFR60
Subpart JJJJ "Standards of Performance for Stationary Spark Ignition Internal Combustion Engines (SI ICE))

No SI ICE at the Carmichael Site.

45 CSR 19 "Permit for Construction and Major Modification of Major Stationary Sources of Air Pollution which Cause or Contribute to Nonattainment"

Because the Carmichael Natural Gas Production Site is located in Marshall County which is an attainment county for all pollutants, it is not subject to 45CSR19.

45 CSR 22 "Air Quality Management Fee Program"

This facility is a minor source and not subject to 45 CSR 30. Chevron is required to keep their "Certificate to Operate" current.

45 CSR 25 "Control Of Air Pollution From Hazardous Waste Treatment, Storage And Disposal Facilities"

No hazardous waste is burnt at this well site; therefore, it is not subject to this hazardous waste rule.

45 CSR 30 "Requirements for Operating Permits"

The facility's emission rates are too small to trigger Title V.

45 CSR 34 "Emission Standards for Hazardous Air Pollutants for Source Categories Pursuant to 40 CFR, Part 63"

40CFR63
Subpart ZZZZ "Nation Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combust Engines"

Subpart ZZZZ establishes national emission limitations and operating limitations for HAPs emitted from stationary RICE located at major and area sources of HAP emissions. The subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations. There are not engines located at the Carmichael site.

For a new stationary RICE located at an area source of HAPs, the applicability requirement is to meet the standards of 40CFR60, Subpart JJJJ.

Site Inspection

No site inspection was conducted for this update. Chevron's Carmichael Natural Gas Production facility is known to the WV DAQ and an Enforcement Inspector is scheduled to inspect the facility.

UTM Coordinates (per application, entry 12.E, F, and G):

Northing	4,415.7	KM
Easting	536.14	KM
Zone	17	

Latitude & Longitude Coordinates (per Chevron's October 17, 2014 legal advertisement):

Latitude:	39.8906
Longitude:	-80.5773

Directions (per application, entry 12A, page 2 of 4):

From Cameron, WV travel North on 250 approximately 6 miles. The entrance to the site road is on the right, 0.6 miles after passing Fork Ridge Road.

Toxicity of Non-criteria Regulated Pollutants

Small amounts of non-criteria regulated pollutants are emitted from the combustion of natural gas in the line heater (BAP-0110), gas scrubber (MBF0030), gas compressor engine (CBA-0050) and vapor destruction unit (ZZZ-0060).

Air Quality Impact Analysis

Modeling was not conducted because the source is an area source will relatively small emissions of criteria pollutants.

Changes to Permit

Front Page	Title changed to Permit to ~~Construct~~Update; R13-3135A; Issue date updated.
Page 2	Permit number at top of page updated to R13-3135A; permit type changed to Class II Administrative Update; the following paragraph added to Description of Change:

> Based on a forecasted natural gas production increase, this update will permit, for the first time, condensate to be stored in the Condensate Storage Tank (ABJ-0014; previously known as the Blowdown Storage Tank). Annual fluid throughput limits to the Produced Water Storage Tank (ABJ-0011) and the Condensate Storage Tank were increased to 183,960 gallons (from 122,640 gallons) and 151,200 gallons (from 630 gallons), respectively. Criteria pollutant emissions for the facility are expected to increase by the following amounts: 1.49 ton/yr VOC and 0.02 ton/yr HAPs.

Page 5	Blowdown Storage Tank changed to Condensate Storage Tank in Emission Units Table.
2.4.1.	Sentence added: This permit supersedes and replaces previously issued Permit R13-3135.
2.5.1.	R13-3135A added to list of permits.
6.1.3.	The maximum throughput ~~to the~~ of produced water ~~storage~~ to the Produced Water Storage tank (ABJ-0011) shall not exceed ~~122,640~~ 183,960 gallons per year.
6.1.4.	The maximum throughput of condensate to the ~~blowdown storage tank~~ Condensate Storage Tank (ABJ-0014) shall not exceed ~~630~~151,200 gallons per year.
6.4.3.	Changed end of last sentence to: Permit Applications R13-3135 and R13-3135A.
7.1.1.	The maximum quantity of ~~blowdown fluids that shall~~ condensate to be loaded (LR-1) from the Condensate Storage Tank shall not exceed ~~630~~151,200 gallons per year.
7.1.2.	The maximum quantity of produced water ~~that shall~~ to be loaded (LR-1) from the Produced Water Storage Tank shall not exceed ~~122,640~~ 183,960 gallons per year.
7.1.3.	Changed end of last sentence to: Permit Applications R13-3135 and R13-3135A.

Attachment 1
Hard Copy of

SOURCE AGGREGATION DISCUSSION

Taken from Evaluation for R13-3135
And
Permit Application for R13-3135

Preliminary Analysis Regarding Applicability of Source Aggregation

The West Virginia Department of Environmental Protection (DEP) has asked for an analysis of how well-site equipment owned and operated by Chevron Appalachia, LLC (Chevron) should be treated in relation to equipment owned and operated by Williams Ohio Valley Midstream (Williams OVM), specifically asking whether or not it would be appropriate to treat them as two stationary sources or as a single source under the Prevention of Significant Deterioration (PSD) and Title V permitting programs. Treating them as a single source would be improper and inconsistent with the intent of the Clean Air Act.

As explained in detail below, the two companies' equipment at or near the West Virginia natural gas well sites are not under common control—even where that equipment might be located near one another. Therefore, these are separate sources under the Clean Air Act and the regulations of the West Virginia Department of Environmental Protection, Division of Air Quality (DAQ). This means that these separate source emissions should not be aggregated in determining applicability of permitting programs.

For these reasons, and for those more fully explained below, aggregation would be inappropriate here.

Background

Chevron is a natural gas producer that acquired several natural gas wells from Chief Oil and Gas LLC (Chief) and AB Resources LLC (AB Resources) in mid-2011. In 2009, Chief and AB Resources entered into a "gathering agreement" with Caiman Eastern Midstream (Caiman) to compress and process the gas produced. Subsequently, Williams OVM purchased Caiman and now owns the gathering system. The natural gas well-sites that Chevron acquired are being produced with equipment typically found at natural gas well-sites, which may include heaters, separators, tanks (produced water, condensate, blowdown), and in some cases, vapor destruction and/or vapor recovery units. The equipment associated with the gathering system includes compressors and dehydration units, all of which are separately owned and operated by Williams OVM. Ultimately, the gas is routed to processing plants, owned by either Williams or MarkWest.

The sites produce and sell condensate, which also must be gathered and processed. Depending on which of the sites is involved, the condensate may be stored in a condensate tank and trucked offsite for processing or may be pumped offsite by pipeline. The condensate is gathered and processed by either Williams OVM or another company, Ergon, which currently contracts with sites that are not pipeline-equipped. Ergon could also truck condensate at sites where the condensate is currently pumped offsite and may be called upon to do so if there is a disruption or Chevron chooses to enter into a contract for that purpose. Both Ergon and Williams would process the condensate at their plants, depending on which of them Chevron contracts with for that service at that site. As a result, there are distinct systems for production and condensate, which may or may not necessitate emission units on site. Chevron owns and operates a production system, and Williams OVM and Ergon own and operate gathering and processing systems for gas and condensate.

As a general matter, Williams OVM's business is to process and transport gas and condensate and Ergon's business is to process and transport condensate produced from wells owned by exploration and production companies. Companies like Williams OVM and Ergon are not producers, and they independently operate whatever equipment they may need to achieve their business goals. In the case of Williams OVM, compression and dehydration equipment and condensate storage and processing equipment are in service to support their business.

Before providing its services, Williams OVM—like its predecessors in interest—enters into contracts to move customers' gas and condensate from receipt points (wells) to delivery points. Moreover, Williams OVM's predecessors in interest had to design the gathering system in such a way to meet its contractual obligations. Gas and condensate entering and leaving Williams OVM's gathering system is not owned by Williams OVM but is rather owned by the producers with whom it contracts. The types of equipment and emission units that are required for gathering gas are typically compressors and dehydrators but may also include vapor destruction or vapor recovery units.

Here, Williams OVM provides pipeline and compression for gas and condensate gathering for 16 wells owned by Chevron. This analysis focuses on one well site in particular—the Carmichael 1H site (Carmichael site). For the Carmichael site, Williams performs gas gathering services, while condensate is sold directly off the pad to Ergon, which trucks it away for processing at its plant.

At the Carmichael site, Chevron, Williams OVM , and Ergon perform separate operations. Chevron and Williams OVM each operate their separate equipment, serving separate functions—production and gathering—under a gas gathering agreement. To be clear, there is no common ownership of the equipment. Moreover, Chevron does not have decisionmaking authority over Williams OVM, nor does Williams OVM have such authority over Chevron, and there is no voting interest of one company in the other or shared board members. Finally, as discussed in more detail below, the key commonalities that EPA looks for in determining if a control relationship exists are not present here.

Consistent with the general arrangement discussed just above, Chevron owns specific equipment at the Carmichael 1H site, and Williams OVM will own distinct gathering and processing equipment. Thus, Chevron owns a heater, one produced water tank, one blowdown tank, a separator, and a vapor destruction unit, whereas Williams OVM will own a dehydrator and sales gas compressor. Although the equipment is located in close proximity at this site, there is not a common control relationship. Chevron cannot direct the operation of Williams OVM's equipment, nor can Williams OVM do the same to Chevron.

Moreover, it is possible that independent third parties might own and operate future wells at or near Chevron's well sites, and if that happens, it is anticipated that the Williams OVM's gathering system will accept any gas produced by these other owners and operators. Chevron does not have a say over what other gas Williams OVM processes.

Regulatory Definitions and Select Guidance

The emissions activities of two or more stationary sources cannot be aggregated unless the sources meet all of the following criteria:

(1) they belong to the same industrial grouping;

(2) they are located on contiguous or adjacent properties; and

(3) they are under common control of the same person or persons under common control.[1]

In addition to the above factors, permitting authorities apply the guidelines established in the 1980 Preamble to EPA's New Source Review regulations. Those guidelines provide that, to be considered a source for aggregation purposes in the PSD and Title V context, the source must: (1) further the purposes of the PSD program, (2) meet a common sense idea of plant, and (3) not include pollutant activities that do not come within an ordinary concept of what constitutes a "building, structure, facility or installation." Permitting authorities have determined that these additional considerations must also be met in order for pollutant-emitting activities to be properly aggregated. Because source determinations are case-by-case, considering the specific facts of the situation,[2] prior agency statements and source determinations related to oil and gas

[1] 40 C.F.R. § 70.2.

[2] Memorandum from Gina McCarthy, Assistant Administrator, Office of Air and Radiation, *Withdrawal of Source Determination for Oil and Gas Industry*, 2 (Sept. 22, 2009) available at http://www.epa.gov/region7/air/nsr/nsrmemos/oilgaswithdrawal.pdf (McCarthy Memo).

activities may be instructive but are not determinative.[3] Thus, under EPA's own guidance, factors unique to the hydraulic-fracturing production and processing must be taken into account in conducting any aggregation analysis.

In August 2012, the U.S. Court of Appeals for the Sixth Circuit rejected an effort by EPA to supplant the case-by-case aggregation analysis discussed above with a "functional interrelationship" test. *Summit Petroleum Co. v. EPA, et al.*, 690 F.3d 733 (6th Cir. 2012). The court reaffirmed that the plain meaning of EPA's regulatory requirements controlled and were governed by a case-by-case analysis.

Similarly, the Department of Air Quality (DAQ) reaffirmed the case-by-case approach in a May 1, 2013, letter to two West Virginia oil and gas trade associations regarding *Aggregation of Sources and Common Control* (May 2013 DAQ Letter). That letter responded to an April 16, 2013 letter from the associations that had expressed concern over recent DAQ source determinations. The associations' letter focused on DAQ's evaluation of whether an entity is under the "control" of another by suggesting that a common control relationship exists whenever 50% or more of the output or services of one company's facility are dedicated to operations at another company's facility. DAQ's response appropriately reinforced the case-by-case nature of source determinations, referencing the Securities and Exchange Commission (SEC) control definition, which considers control to be "the possession, direct or indirect, or the power to direct or cause the direction of the management and policies of a person (or organization or association) whether through ownership of voting shares, contract or otherwise," which has been applied by EPA and permitting authorities. DAQ explained that common control exists where there is an ownership relationship—*i.e.*, the same parent company or subsidiary of a parent company or where an entity has decision-making authority over the operation of the second entity through a contractual agreement or voting interest. Where neither of these exists, as here, DAQ stated that it would next look at "whether there is a contract for service relationship between the two entities or if a support/dependency relationship exists between the two entities *such that a common control relationship exists.*"

Other regulatory agencies also have acknowledged the need for flexibility in source determinations in the oil and gas industry, noting that the "locations of natural gas wells and surface facilities are determined by a variety of factors," many of which are beyond the control of the oil and gas production companies that drill the wells. *See* In the Matter of Kerr-McGee/Anadarko Petroleum Corporation, Frederick Compressor Station, *Response of Colorado Department of Public Health and Environment, Air Pollution Control Division, to Order Granting Petition for Objection to Permit* at 7 (July 14, 2010) (CDPHE Frederick Station Response). For example, the Colorado Department of Public Health and Environment (CDPHE) specifically cited to spacing requirements for gas wells, which are established and regulated by a number of different entities in that state, including the Colorado Oil and Gas Conservation Commission on private and state-owned lands, Federal agencies such as the Bureau of Land Management on Federal lands, and Tribal authorities on Tribal lands. CDPHE further observed that oil and gas production companies must also negotiate surface use agreements, pipeline agreements and rights-of-way with surface right owners in the areas where wells are being drilled and developed, acknowledging that these agreements, which often focus on minimizing the surface footprint and impact of the oil and gas operations, dictate the locations of surface facilities, minimum offsets from adjoining boundaries and the number of well pads allowed. Geological, topographical, and engineering considerations, along with logistical factors such as access restrictions and the availability of power, also drive siting decisions.

Aggregation Analysis

Because the Chevron and Williams OVM facilities will operate under the same two-digit SIC code (here major group 13), the key questions are whether the operations are on contiguous or adjacent property and are under common control. Although the operations are located in close proximity, there is separation of more

[3] CDPHE Frederick Station Response at 8.

than 500 feet in many instances, and, as the CDPHE recognized in Colorado, there are non-environmental-regulatory reasons explaining this proximity. In addition, Chevron and Williams OVM operations are not under the control of the same person or persons under common control. Indeed, they each will separately operate their separate equipment, and there is no strict interdependency but rather a contractual relationship between an upstream and midstream operator (which, as discussed below, reflects the unique nature of the oil and gas industry).

1. Located on Contiguous or Adjacent Properties

Emissions activities must be located on contiguous or adjacent property to be considered a single source. In keeping with the fact-specific nature of the aggregation analysis, there is no exact distance that would cause two activities to be considered contiguous. Physical proximity is the main, if not only, factor for determining whether properties are contiguous or adjacent, and consideration of functional interdependence of two activities is improper in assessing this criterion. *See* May 2013 DAQ Letter. This is consistent with the Sixth Circuit's decision in *Summit Petroleum*. Although, in certain instances, EPA and some state environmental agencies have included a functional interdependence test, Chevron agrees with DAQ's approach to that issue and with the *Summit Petroleum* decision rejecting an expansion of the three-pronged aggregation analysis.[4]

Here, some of the natural gas well pads for which Chevron seeks permits—the Carmichael 1H site in particular—feature Chevron equipment and Williams OVM equipment directly adjacent on the same well pad, but at other sites, the equipment is separated by some distance. As noted by the court in *Summit Petroleum Co.*, there is no bright line distance for determining adjacency. Where the Williams OVM equipment is located on property that is separated by a road or otherwise from the location of the Chevron equipment, the contiguous/adjacency criterion would not be met and such equipment could not be aggregated for permitting purposes. With respect to those situations where the Chevron equipment and Williams OVM equipment are located directly on the same well pad, one must consider the myriad of technical and regulatory reasons that drive a siting determination.

Moreover, it is important to recognize that, although equipment may be located on contiguous or adjacent property, that proximity should not be used as a basis for supporting a positive finding under the separate, common-control criterion (which we discuss below). Indeed, the co- or nearby-location of such equipment is a function of terrain and siting requirements in West Virginia. These are selected based upon non-environmental regulatory requirements, such as to minimize the number of wells, and on negotiated agreements, such as surface-use agreements, pipeline agreements, and rights-of-way agreements with surface right owners who seek to minimize the site footprint and to consolidate equipment that might otherwise have been separately located. This point has been acknowledged by the CDPHE decision in the case of the Frederick Compressor Station in Colorado, discussed above, *CDPHE Frederick Station Response* at 7-8, and CDPHE emphasized that the siting considerations in the oil and gas industry are "unique and inherent" to that industry and do not necessarily establish a conclusion on the relationship between two facilities that might apply based on EPA guidance for other industrial sectors. CDPHE indicated its intent to evaluate issues, like common control, within the context of the oil and gas industry rather than concluding that co-location indicated a *per se* "control relationship." *Id.*

In sum, although spatial limitations of available drilling and production sites, terrain requirements, and a desire to minimize agreements with landowners drive the location of gathering equipment nearby wells, this in no way should be used to support aggregation of separately owned and operated equipment for permitting purposes.

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[4] While EPA is not following the Summit Petroleum decision outside the 6th Circuit, Chevron believes that the reasoning therein is likely to be applied in other circuits and, in any case, DAQ is free to adopt the reasoning, whether or not DAQ is "following" the decision.

2. Under Common Control of the Same Person or Persons Under Common Control

Even if equipment is located at a contiguous/adjacent location, if there is separate ownership and operation, and the operations are not under the control of the same person or persons under common control, the sources remain separate. This factor alone disposes of the analysis and compels a conclusion that the sources may not be aggregated in determining permitting applicability.

Although "common control" is not defined in the rules, source specific determinations and guidance have informed its meaning since EPA issued the underlying regulations in 1980. EPA has identified three alternative methods of establishing common control for purposes of source aggregation under Clean Air Act Titles I and V:

(1) common ownership;

(2) operational control; and

(3) control relationship.[5]

As to the first method, here, Chevron and Williams OVM do not have common ownership. As to the second, Chevron does not have decision-making authority over Williams OVM's operations, nor does Williams OVM have any such control over Chevron's operations, and there is no voting interest of one company in the other.

With respect to the third method of analyzing "common control"—looking at the "control relationship"—this effectively captures the concept in the SEC guidance of "indirect" control. EPA has identified several factors that it considers, which include several that militate against aggregation here.

- EPA focuses on whether the facilities share common workforces, plant managers, security forces, corporate executive officers, or board of executives. They do not here.
- EPA also considers whether the facilities share common payroll activities, employee benefits, health plans, retirement funds, insurance coverage, or other administrative functions. They do not here as well.
- Another factor is whether the facilities share equipment, other property, or pollution control equipment. Here, they will not. Although the equipment at the Carmichael site may be co-located, it will not be shared. Moreover, it is important to recognize that this separately owned and operated equipment is to be located near to each other due to the space and other considerations discussed above, not for a control purpose.[6] It was Williams OVM's decision not to utilize a centralized gas gathering system, not Chevron's, that resulted in co-location. Thus, a common control interest is not present here as well.
- Yet another factor is whether the managing entity of one facility will be able to make decisions that affect pollution control at the other facility, and whether the facilities will share intermediates, products, byproducts, or other manufacturing equipment. Here, those factors are again not present—one will provide the service of gathering while the other produces.
- Finally, another factor that EPA has used at times is interdependence, though that factor distorts a traditional control analysis. Here, there will be separate responsibility for compliance with air quality

[5] Letter from Richard R. Long, USEPA Region 8, to Julie Wrend, Colorado Department of Public Health and the Environment, Re: Single Source Determination for Coors/TriGen (November 12, 1998) ("Long Letter").

[6] Williams is installing at each site produced water tanks that it will own and operate (applications are pending or will be submitted to DAQ by Williams OVM). The drivers behind the request are operational and safety requirements, primarily as it relates to overpressure protection. To address process safety concerns, Williams OVM's produced water tanks will manage blowdown from the Williams OVM dehydration units.

control requirements and liability for any violations. Although contracts are in place for Williams OVM to handle gas for Chevron, Williams OVM expects, as opportunities arise, to receive gas from other producers in the future, and Chevron has preserved the right to have its gas gathered or processed by other facilities. Moreover, with respect to the gas and condensate gathering systems, as noted above, Chevron uses Ergon to bring condensate to market at this site and could do so as well at other sites.

Chevron alone is and will be responsible for any decisions to produce or shut-in wellhead facilities and will have no control over the equipment installed, owned, and operated by Williams OVM. Moreover, if a well is shut in, for example, Williams OVM could use its compression equipment to serve other wells in the area. These characteristics are not consistent with sources under common control.

It would therefore be erroneous for DAQ to conclude that, in the face of all the indications of lack of common control noted above, because Williams OVM's equipment is currently servicing only the Chevron wells, a *de facto* control relationship exists. Such a simplistic conclusion would be inappropriate in light of the complexities of this industry and the information provided in Section 1 above, where we explained that co-location is driven largely by footprint and other non-air quality regulatory issues. It is also important to recognize that a "source determination" cannot be a one-way street. In other words, it applies to all emissions units in a complete manner. Thus, if Williams is determined to be an independent source because of its ability to handle gas from multiple customers, then concomitantly, Chevron must also be a separate source. It is not reasonable for DAQ to determine that Source A, was independent of Source B because Source A could process gas from numerous producers while simultaneously determining that Source B must be aggregated with Source A because Source B may only send its product to Source A. Under the Clean Air Act, emissions units are either part of one stationary source or they are not. To conclude otherwise would require DAQ to continually determine how much of Source A's emissions must be allocated to Source B. This is a clear reason why the Colorado agency appropriately decided that the unique nature of oil and gas operations militated against aggregation in situations such as this where there are multiple operators related to gas and condensate with respect to gathering and production.

The above conclusion is further supported upon consideration of the terms of the Gas Gathering Agreement (GGA), which clearly indicate separate operations:

- The agreement was the byproduct of an arms-length transaction between unrelated parties.

- The GGA provides for the construction of a pipeline and ancillary equipment to gather the gas, which includes the compression and dehydration equipment Williams OVM needs to meet its contractual obligations. Because this equipment is part of the overall gas gathering system, and it is clear that the system overall should not be aggregated with the various wells, and treating this equipment separately from the system would be inappropriate.

- Chevron has the right to withdraw a well from the agreement if it determines it would be not be economical to use the Williams OVM gathering system and to use other means (including other pipelines) to move its gas.

- The GGA makes it clear that the location of the gathering equipment at the well site is for the convenience of the gatherer in constructing its gathering system and not for the producer's sake, explicitly indicating that the producer can reject the gatherer's location at the well site if there is not sufficient space.

- The GGA addresses commingling of gas from other producers subject to certain quality requirements, referencing "all sources in Gatherer's system," indicating that Williams OVM is not captive to Chevron in this situation and that a control relationship does not exist.

Indeed, a business relationship to achieve a the purpose of marketing gas between upstream and midstream should not dictate the conclusion of the control analysis, which relates not to whether one entity has agreed to enter a business relationship based on the distinct structure of the particular industry, but instead bears on whether one can dictate the other's operations. Here, there is no such control, and as noted above, Chevron can obtain processing support from other entities and in fact uses another entity to process its condensate at the site. Williams OVM and Ergon are business partners not controlled entities. Moreover, if a support relationship should have any bearing at all on the aggregation analysis, it already factors into the SIC prong, which takes into consideration a common industrial purpose. It would be inappropriate to conflate the factors that were clearly meant to be separate by grafting a support-facility analysis onto the control prong.[7]

And, even if it were appropriate to graft onto the control-relationship analysis the support facility concept, any servicing guidelines must be viewed as only one factor among many in the control-relationship analysis. Other factors include the degree to which the primary activity exerts control over the supporting activity's operations, the nature of the agreements, the reasons for the support activity's presence on the same site as the primary activity, and even the market realities of the service relationship. Considering those factors here, the parties negotiated an arms-length arrangement, they do not have any operational or ownership control over each other's facilities, and each remains free to contract with other parties in the future.[8] In sum, there is no direct control and there should be no finding of indirect control between these parties.

Determination

For the above reasons, emissions from the Chevron production sources at the Carmichael site and from the Williams OVM gathering system equipment (*e.g.*, their compressors, dehydration units, and ancillary equipment) should not be aggregated for purposes of determining applicability of Clean Air Act Title I or Title V permitting programs or West Virginia's air permitting regulations. Even if the sources are at contiguous/adjacent property, these operations are separately owned and operated and are not under the control of the same person or persons under common control.

[8] We understand that that DAQ raised the issue of consistency with another source-specific, case-by-case determination, the Long Letter. We note that there are several distinguishing factors that make the Long Letter inapplicable here. First, the Long Letter is not a rulemaking, was a case-by-case determination, and is not binding on DAQ. Second, the facts in that case are distinct from those here. There, a power plant (previously owned by Coors) had been sold to TriGen and was going to continue to provide 100% of Coors power needs. In addition, Coors was relying on the boiler for pollution control to meet its regulatory obligations under a consent decree settlement. That is not the case here. Williams OVM is not enabling Chevron to produce its gas. Chevron is producing the gas and needs to have it processed by another company, here, Williams OVM. That is entirely different from the integrated nature of the TriGen operation to the Coors operation. Third, as recognized by Colorado, considerations related to the oil and gas business are "unique and inherent" to that industry and do not necessarily establish a conclusion on the relationship between two facilities that might apply based on EPA guidance for other industrial sectors. In other words, it does not make sense to analyze the relationship between midstream and upstream oil and gas companies in the same manner that one would a power generator and a traditional manufacturing plant. Finally, the Colorado determination related to the Frederick Station was issued in 2011, more than a decade after the Long Letter, so DAQ can if it chooses, rely on that determination to distinguish the unique nature of this industry in making its determination. .