LIST OF EXHIBITS

Exhibit 1

LARIMER COUNTY | Community Development

P.O. Box 1190, Fort Collins, Colorado 80522-1190, Planning (970) 498-7683 Building (970) 498-7700, Larimer.org

April 12, 2024

Re: Certification of Good Faith Efforts between Larimer County and Prospect Energy

To whom it May Concern

I, Matt Lafferty, I my position as Local Government Designee for Larimer County, certify that I have conferred in good faith with Prospect Energy. This good faith conferral was in the form of a letter sent to Prospect Energy dated February 26, 2024, and a follow up meeting with Prospect Energy and the City of Fort Collins on February 29, 2024.

I also certify that the 19 wells listed in the County's Rulle 211 request have been low producing for the last three years. I utilized the COGCC website to determine that the production levels for the 19 wells were below two barrels of oil equivalent per day for at least the past three years.

Respectfully,

Matt Lafferty
Larimer County LGD; Principal Planner
Larimer County Community Development Department

LARIMER COUNTY

Exhibit 2

Environmental Services
222 Laporte Ave
Fort Collins, CO 80522

970.221.6600
970.224.6177 - fax
fcgov.com

DATE: April 2, 2024
TO: Colorado Oil and Gas Conservation Commission
RE: Certification of Good Faith Efforts between the City of Fort Collins and Prospect Energy

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To Whom it May Concern,

I, Cassie Archuleta, in my position as Local Government Designee for the City of Fort Collins, certify that I have conferred in good faith with Prospect Energy. This good faith conferral occurred jointly with Larimer County on August 22, 2023. Another conferral occurred on February 29, 2024.

I also certify that the 19 wells listed in the City of Fort Collins and Larimer County's Rule 211 request have been low-producing for the past three years. I used the COGCC website to determine that the production levels for the five wells within the City were below two barrels of oil equivalent per day for at least the past three years.

Respectfully,

Cassie Archuleta
City of Fort Collins
Local Government Designee
Air Quality Program Manager

LARIMER COUNTY | Community Development

P.O. Box 1190, Fort Collins, Colorado 80522-1190, Planning (970) 498-7683 Building (970) 498-7700, Larimer.org

February 26, 2024

Prospect Energy LLC
c/o Ward Giltner
1036 Country Club Estates Dr
Castle Rock, CO 80108
(303) 489-8773
Email: wgiltner@yahoo.com; prospectenergy@icloud.com

Re: Larimer County and City of Fort Collins analysis of Prospect Energy wells

Dear Mr. Giltner,

As you may recall, on August 22, 2022, Larimer County, in coordination with the City of Fort Collins, discussed with you the potential to have some of the wells and sites operated by Prospect Energy LLC plugged and reclaimed as part of your financial assurances plan. We are grateful that some of the wells we suggested for plugging and reclamation were included in your approved financial assurance plan.

Since our last meeting in 2022, the City and County have continued to coordinate efforts to understand the viability and necessity of the wells Prospect Energy LLC operates and again we have assembled a list of wells that we would like to see plugged and the sites reclaimed, see Attachment A.

Given the revised list, we are respectfully requesting a meeting with you to discuss several of Prospect Energy LLC oil and gas and injection wells we believe are no longer used or useful and may pose a threat to the public health, safety and welfare and the environment and thus should be considered for plugging and reclamation pursuant to Rule 503(g)(12) and Rule 211.

Please call me if there are any questions regarding this correspondence of the attachments. We look forward to our meeting on February 29, 2024 @ 9:00 AM.

Respectfully,

Matt Lafferty
Larimer County LGD; Principal Planner
Larimer County Community Development Department

CC:
Board of County Commissioners
Lorenda Volker, County Manager

Rebecca Everette, Community Development Director, Larimer County
Lesli Ellis, CPIR Director, Larimer County
Laurie Kadrich, Assistant County Manager
Frank Haug, Assistant County Attorney II
Matt Sura, Special Counsel for Larimer County
Lea Schneider, Environmental Health Planner, Larimer County
Cassie Archuleta, Air Quality Program Manager, City of Fort Collins
Jack R. Luellen, Special Counsel @ Buchalter

ATTACHMENT A: *20 "Subject Wells."*
Production numbers taken from COGIS.

API #	Well Title	Spud Date	Well Status	City	Prod. 2020	Prod. 2021	Prod. 2022	Prod. 2023	Proposed to plug
506905113	MEYER 1	12/2/1924	SI		0.854	0.0164	0.0164	0	
506905114	MEYER 3	12/8/1952	SI		0.041	0.011	0	0	
506905115	WORTH (MUDDY UNIT) 1	10/24/1924	TA		0	0	0	0	12/6/2023
506905132	COMMUNITY 3	12/12/1956	SI		0.019	0.0247	0	0.027	
506905136	MARTINEZ, F G, 2	6/18/1960	SI		0	0	0	0	5/17/2024
506906083	PETERSON 14-20	4/18/1979	SI		IJ	IJ	IJ	IJ	
506906094	MUDDY SANDSTONE 30-6	6/14/1980	SI	Ft Collins	1.35	0.5178	0.671	0	
506906095	MSSU 30-7	6/24/1980	IJ	Ft Collins	IJ	IJ	IJ	IJ	
506906137	COMMUNITY 6	11/19/1981	PR		0.035	0.509589	0	0.28	
506906255	MSSU 30-10	5/27/1985	SI	Ft Collins	0	0	0	0	
506906284	MSSU 30-17	2/27/1988	IJ	Ft Collins	IJ	IJ	IJ	IJ	
506906289	MSSU 19-9	4/17/1988	IJ		IJ	IJ	IJ	IJ	
506906307	MSSU 20-2	5/13/1992	SI		0.032	0.0329	0.075	0	
506906309	MSSU 20-1	5/21/1992	SI		0	0	0	0	5/17/2024
506906310	CHEYENNE RIDGE 7-1	8/29/1992	SI		0.035	0.2137	0.058	0.066	
506906312	MSSU 17-1	9/10/1992	TA		0	0	0	0	5/17/2024
506906313	MSSU 19-10	7/15/1992	TA/SI		0	0	0	0	
506906316	MSSU 31-1	8/4/1992	SI	Ft Collins	IJ	IJ	IJ	IJ	5/17/2024
506906332	KIIX 1	5/20/2005	SI		0.175	0.0329	0	0	
506906399	MARTINEZ 3	6/25/2010	SI		0.178	0.0795	0	0	

March 12, 2024

Mr. Matt Sura, Esq.
Law Office of Matt Sura
7354 Cardinal Lane
Longmont, CO 80503

Ms. Cassie Archuleta
City of Fort Collins

Mr. Matt Lafferty
Larimer County

Re: Review of wells in the Fort Collins Field relative to Colorado ECMC Rule 211

Dear Sirs and Madam:

Introduction

This letter report serves to document the work performed by WSP to assist the Law Office of Matt Sura regarding a request before the Colorado Energy and Carbon Management Commission (ECMC) for plugging and abandonment of wells in the Fort Collins Field that are no longer used or useful, under Rule 211. A list of 19 wells has been analyzed, all currently operated by Prospect Energy, LLC.

ECMC Rule 211 provides for requiring the plugging and abandonment (P&A) and reclamation of wells that present adverse impacts to the public or are no longer "used or useful". The text of the rule is provided below:

Rule 211 *"An Operator of a Well will Plug and Abandon the Well, Remediate any contamination pursuant to the Commission's 900 Series Rules, and Reclaim the Well Site pursuant to the Commission's 1000 Series Rules if the Commission, following a hearing pursuant to Rule 503.g.(12), determines that Plugging and Abandoning is reasonable and necessary to protect or minimize adverse impacts to public health,*

> *safety, welfare, the environment, or wildlife resources, or that the Well is no longer Used or Useful."*

Of the 19 wells reviewed in this assignment, all are located within 2,000 feet of homes, 17 are located within 1,000 feet of homes, and 13 are located within 500 feet of homes. The subject analysis, however, addresses only whether the wells are used or useful and not how or whether they may impact the public.

The 19 wells reviewed are shown in Table 1, including their lease name and well number, API number, and surface location. Figure 1 shows the 19 wells, highlighted in pink, along with other nearby wells. All well locations shown on this map are bottom-hole locations.[1]

Table 1 List of 19 Wells Reviewed

API #	Well_Name	Well_Num	Current Status	Produced within Last 3 Years?	Surface Latitude	Surface Longitude
0506905113	MEYER	1	SI Producer	Y	+40.64119	-105.05004
0506905114	MEYER	3	SI Producer	Y	+40.64064	-105.05034
0506905115	WORTH (MUDDY UNIT)	1	TA Producer		+40.64124	-105.05429
0506905132	COMMUNITY	3	SI Producer	Y	+40.66556	-105.03904
0506905136	MARTINEZ, F G	2	SI Injector		+40.67459	-105.03655
0506906094	MUDDY SANDSTONE UNIT	30-6	SI Producer	Y	+40.63592	-105.04537
0506906095	MSSU	30-7	Active Injector		+40.63615	-105.04039
0506906137	COMMUNITY	6	SI Producer	Y	+40.66658	-105.03634
0506906255	MSSU	30-10	SI Injector		+40.63843	-105.04707
0506906284	MSSU	30-17	Active Injector		+40.63710	-105.04012
0506906289	MUDDY SANDSTONE UNIT	19-9	Active Injector		+40.64363	-105.03939
0506906307	MSSU	20-2	SI Producer	Y	+40.65096	-105.03394
0506906309	MSSU	20-1	SI Producer		+40.64721	-105.03489
0506906310	CHEYENNE RIDGE	7-1	SI Producer	Y	+40.66975	-105.04409
0506906312	MSSU	17-1	SI Injector		+40.65442	-105.03383
0506906313	MSSU	19-10	SI Injector		+40.64493	-105.05290
0506906316	MSSU	31-1	SI Injector		+40.62551	-105.04716
0506906332	KIIX	1	SI Producer	Y	+40.64945	-105.04964
0506906399	MARTINEZ	3	SI Producer	Y	+40.67410	-105.03717

SI – Shut-in, TA – Temporarily Abandoned

[1] Although most of the wells in the field are vertical, a few were drilled directionally and so have different surface and bottom-hole locations.

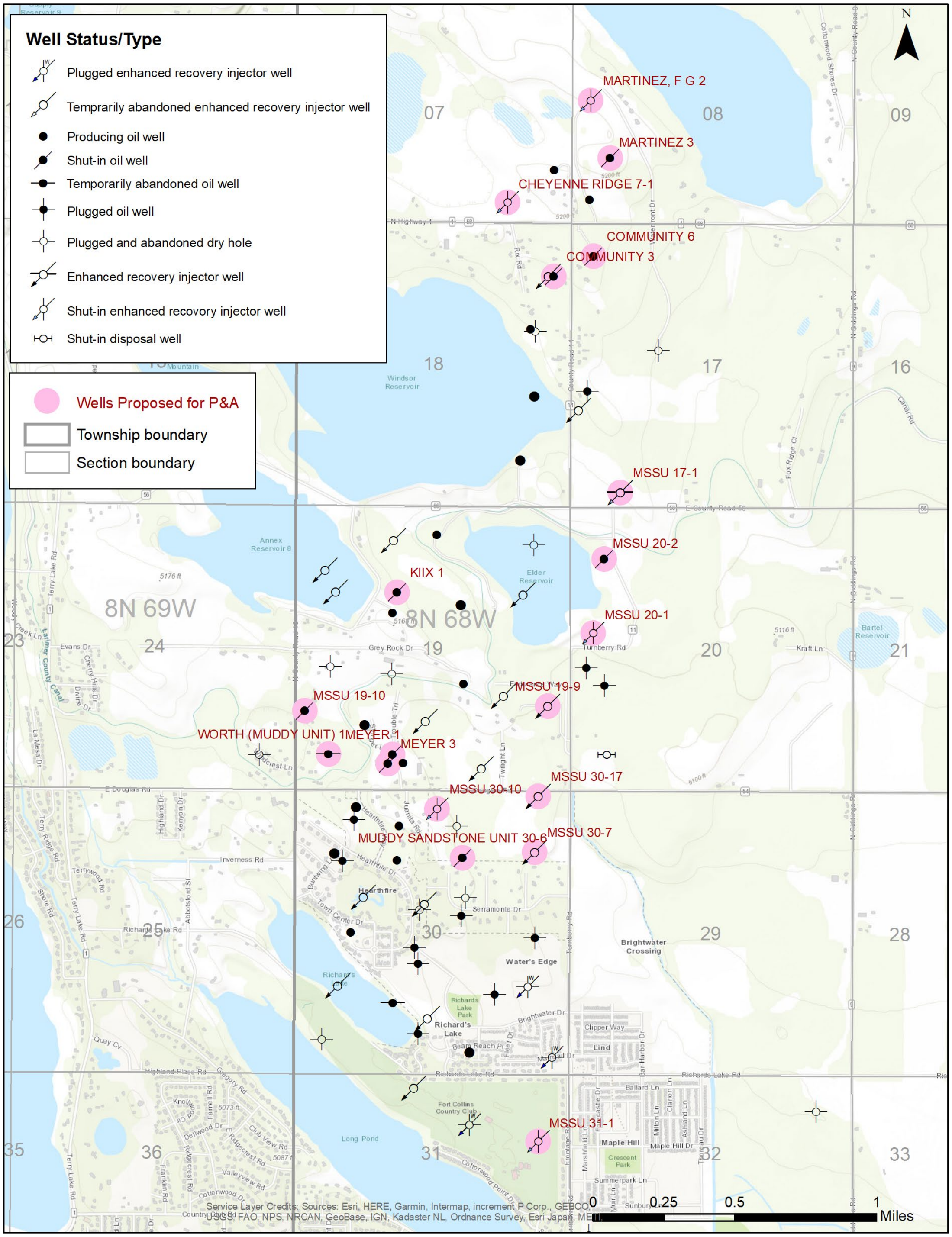

Figure 1 Fort Collins Field Wells

Scope of Work

The following analyses were performed for the Fort Collins Field as a whole:

- Review number of wells and production zones
- Review wells that have been fractured and refractured
- Review wells with recompletions
- Review other reservoirs producing within 10-mile radius
- Literature research on Fort Collins Field, especially original oil in place (OOIP) and expected waterflood performance of the Muddy waterflood unit

The following analyses were performed on the listed 19 wells:

- Calculation of average production for the previous three 12-month periods in barrels of oil equivalent per day (BOEPD)
- Review of water/oil ratio (WOR) versus cumulative oil production for each Muddy producer on the list
- Cash flow analysis on ten wells with production post 01/2020

Detailed discussions on the above analyses are provided below.

Analysis of All Wells in Fort Collins Field

The Fort Collins Field is located on the east side of Larimer County, Colorado, and on the north side of the city of Fort Collins. The Field started production in the 1940s. A total of 59 wells have commercially produced from the field: many of these have already been P&A'd.

WSP has reviewed well records and production and injection history in the Fort Collins Field. The main producing formation in the Fort Collins Field, as well as an area within a 10-mile radius, is the Muddy Formation. A unit was formed for the purpose of waterflooding the Muddy reservoir to enhance oil production. No literature was found regarding geology, expected performance, or OOIP of this unit or field. No refracturing treatments were found to have been conducted in the Fort Collins Field.

Table 2 shows a summary of which reservoirs (Producing Zone Name) have produced from the Fort Collins Field, along with cumulative production and the number of completions in each reservoir.[2] By far, the majority of the production has been from the Muddy. No additional reservoirs were found to have produced within a 10-mile radius of the Fort Collins Field. This

[2] Although monthly production records are available publicly only since 1970, the records for older wells include cumulative production prior to 1970. The accuracy of these older cumulative records is unknown.

information is a preliminary indication that, even if it were likely to be approved from a regulatory standpoint given the proximity to homes and other structures, the potential for recompletion in other reservoirs is limited. Figure 2 is a stratigraphic column showing these formations.

Table 2 Summary of Production by Completed Interval

Producing Zone Name	Cum Oil, bbls	Cum Gas, MCF	Cum Water, bbls	# Completions
NIOBRARA / DAKOTA	398	0	26,413	1
CODELL	18,245	22,602	4,844	3
DAKOTA J/SD/	28,145	0	726,641	1
DAKOTA D/SD/	51,354	9,940	0	1
NIOBRARA	53,248	35,932	339,549	6
DAKOTA	200,939	24,618	4,666,675	3
LYONS	338,915	15,213	834,425	4
MUDDY /SILT/ SH/ SD/ / DAKOTA J/SD/	2,750,034	157,565	33,357,185	21
MUDDY /SILT/ SH/ SD/	3,573,504	270,210	46,086,619	32
Grand Total	**7,014,782**	**536,080**	**86,042,351**	**72**

Recompletion in the Codell has been suggested by the operator as a viable alternative to plugging these wells. Table 2 shows that significant amounts of gas are produced along with the oil from the Codell, as is normal in the area; therefore, the lack of a gas sales line in the area of the subject wells would present a significant difficulty for this strategy.

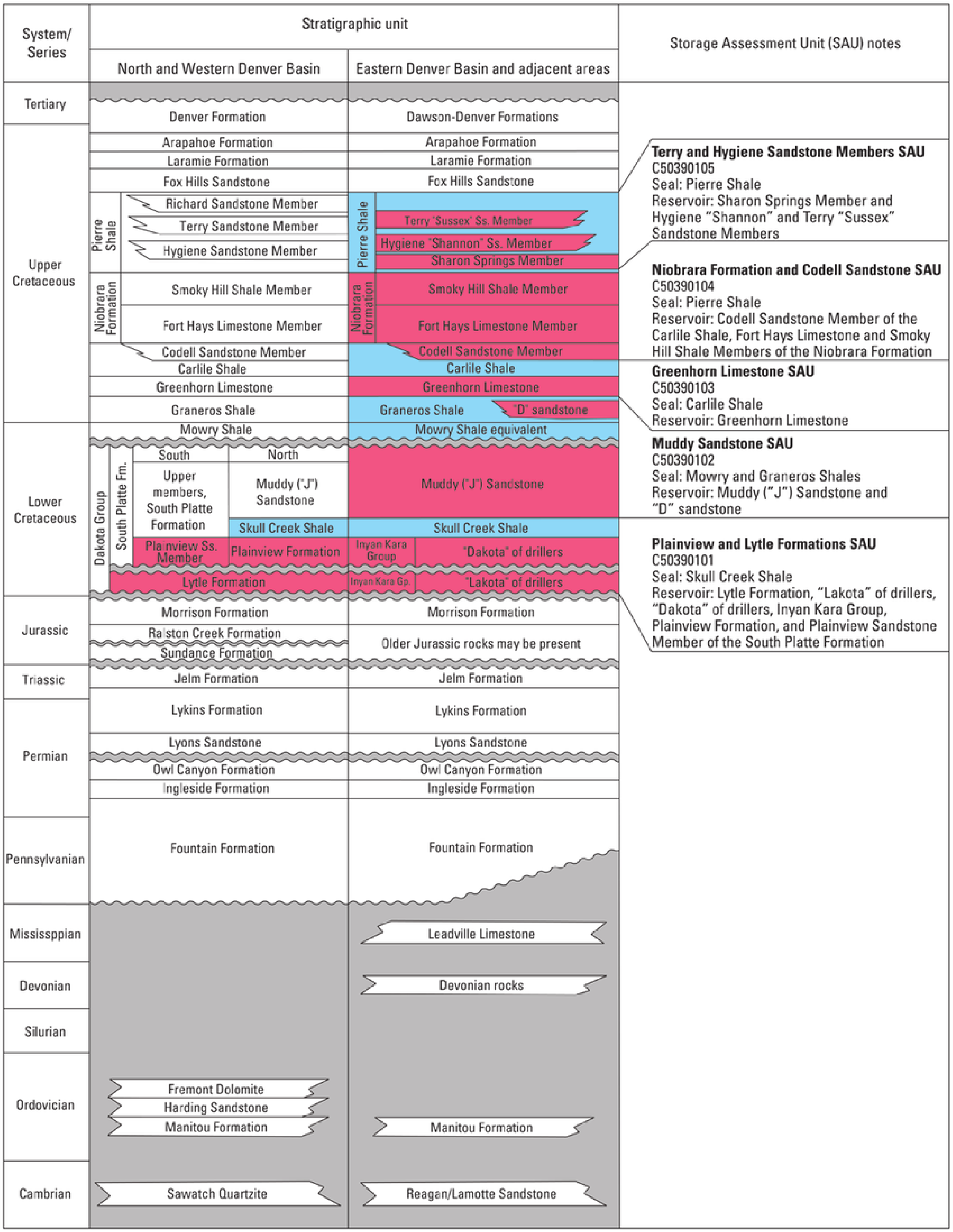

Figure 1 Stratigraphic Column Eastern DJ Basin
from Drake, et. al., USGS, 2014

In order to consider the upside potential for recompletion of any of the 19 wells in other producing formations, WSP has reviewed well records for the nine wells in the Fort Collins Field which were recompleted in other zones, regardless of whether they are on the list of 19 (Table 3). These records show that none of the recompletions were particularly successful in terms of the low cumulative oil resulting from the newly completed zones.

Several horizontal wells are producing or are permitted to be drilled within 10 miles to the east of the field, with completions in the Niobrara or Codell reservoirs. Because the Fort Collins Field is located so close to homes and other structures, and the lack of a gas sales line in the area, it is not expected that any permits would be issued for either new wells or recompletions to different reservoirs in existing wells.

Table 1 Wells with Recompletion in the Fort Collins Field

Hole Direction	Production ID	Primary API	Lease Name	Well Num	Resv Onshore	Oil Cum	Max Oil	First Prod Date	Last Prod Date
VERTICAL	105001005726	05069051130000	MEYER #1&2	1	DAKOTA	186093	1088	1948-01-01	1997-12-31
VERTICAL	105001075504	05069051130000	MEYER #1&3	1	NIOBRARA-DAKOTA	398	151	1998-01-01	1998-11-30
VERTICAL	105001069051130 0DKTA	05069051130002	MEYER	1	DAKOTA	14523	277	1999-08-01	2022-01-31
VERTICAL	1050010690513200LYNS	05069051320000	COMMUNITY	3	LYONS	333720	1710		2012-06-30
VERTICAL	A079225	05069051320001	COMMUNITY	3	DAKOTA	323	109	2014-04-01	2023-06-30
VERTICAL	1050010690608300LYNS	05069060830000	PETERSON	14-20	LYONS	1647	469	1979-06-01	1981-02-28
VERTICAL	A005954	05069060830002	PETERSON	14-20	ENTRADA				
VERTICAL	1050010690613700LYNS	05069061370001	COMMUNITY	6	LYONS				
VERTICAL	1050010690613700MDDYJ	05069061370001	MUDDY UNIT	6	J MUDDY	22	22		1999-01-31
VERTICAL	1050010690613700CODL	05069061370002	COMMUNITY	6	CODELL	3425	176	2008-09-01	2022-07-31
VERTICAL	1050010690625400MDDY	05069062540000	FORT COLLINS	30-9	MUDDY				
VERTICAL	A012735	05069062540002	HEARTHFIRE	1	NIOBRARA	23261	1965	2010-12-01	2023-09-30
VERTICAL	A068966	05069062540003	HEARTHFIRE	1	CODELL	14422	2189	2017-05-01	2023-09-30
DIRECTIONAL	1050010690630500MDDYJ	05069063050000	MUDDY UNIT	30-15	J MUDDY	7422	620		2002-04-30
DIRECTIONAL	A014984	05069063050001	MSSU	30-15	NIOBRARA	54	25	2011-04-01	2012-06-30
DIRECTIONAL	1050010690630700MDDYJ	05069063070000	MSSU	20-2	J MUDDY				
DIRECTIONAL	1050010690630700NB-CD	05069063070001	MSSU	20-2	CODELL	398	57	2008-04-01	2022-06-30
DIRECTIONAL	1050010690631000MDDYJ	05069063100000	MSSU	7-1	J MUDDY	180	180		1999-01-31
DIRECTIONAL	A016898	05069063100001	CHEYENNE RIDGE	7-1	NIOBRARA	1823	1008	2011-04-01	2022-07-31
DIRECTIONAL	A012781	05069063990000	MARTINEZ	3	MUDDY	2752	119	2011-01-01	2019-11-30
DIRECTIONAL	A033438	05069063990001	MARTINEZ	3	NIOBRARA	2697	192	2013-08-01	2021-10-31

Analysis of 19 Wells

Production Rate in Barrels of Oil Equivalent

Additional analyses were performed on the wells on the list provided by the Client. In particular, these wells were analyzed to determine whether they meet the requirement of being no longer used or useful.

The ECMC rules include the following provision, in Rule 503 g (12):

"The Relevant Local Government or Surface Owner may file an application to Plug and Abandon a Well or close an Oil and Gas Location pursuant to Rule 211. Such application by a Relevant Local Government or Surface Owner will include: . . .A certification that the Well has been a Low Producing Well each year of the previous three years;"

Further, the Definitions section of the ECMC rules states that

"LOW PRODUCING WELL means an oil or gas Well that produces a daily average of less than 2 barrels of oil equivalent ("BOE") or 10 thousand cubic feet of natural gas equivalent ("MCFE") of gas over the previous 12 months."

Of the 19 wells, nine have had some production within the past three years. Table 2 shows these wells with the average production for the three previous 12-month periods. These averages are all well below the 2 BOEPD threshold.

Table 2 Average Daily Production Rates for Wells with Production in Last Three Years

Lease Name	Well Number	API	12-mo prev	Liquid	Gas	Water	12-mo BOPD	12-mo BOEPD
			1	0	0	0	0.0	0.0
			2	6	0	0	0.0	0.0
MEYER	1	05069051130002	3	6	0	0	0.0	0.0
			1	0	0	0	0.0	0.0
			2	0	0	0	0.0	0.0
MEYER	3	05069051140001	3	11	0	0	0.0	0.0
			1	10	0	1,975	0.0	0.0
			2	0	0	0	0.0	0.0
COMMUNITY	3	05069051320001	3	16	0	0	0.0	0.0
			1	0	0	0	0.0	0.0
			2	372	0	17,672	1.0	1.0
MUDDY SANDSTONE UNIT	30-6	05069060940000	3	62	0	0	0.2	0.2
			1	60	0	0	0.2	0.2
			2	137	0	0	0.4	0.4
COMMUNITY	6	05069061370002	3	199	0	0	0.5	0.5
			1	0	0	0	0.0	0.0
			2	27	0	41	0.1	0.1
MSSU	20-2	05069063070001	3	12	0	0	0.0	0.0
			1	24	0	90	0.1	0.1
			2	21	0	147	0.1	0.1
CHEYENNE RIDGE	7-1	05069063100001	3	92	0	0	0.3	0.3
			1	0	0	0	0.0	0.0
			2	0	0	0	0.0	0.0
KIIX	1	05069063320001	3	12	0	0	0.0	0.0
			1	0	0	0	0.0	0.0
			2	0	0	0	0.0	0.0
MARTINEZ	3	05069063990001	3	61	0	0	0.2	0.2

Water/Oil Ratio Performance

The performance of the Muddy producers on the list was evaluated with respect to the water/oil ratio (WOR) versus cumulative oil production. This plot is commonly used for wells in a waterflood to evaluate their likely future performance, ultimate recovery potential, and economic feasibility of continued production. The WOR vs cumulative oil production graphs for the Muddy Wells are provided in Appendix A.

As the WOR of a well grows higher, which typically happens along a straight line on the semi-log plot of WOR vs. cum. oil, the economics of continued production grow worse, as less revenue is generated from produced oil and more costs are incurred to re-inject the produced water. Although the economic limit of a high WOR varies with project and time based on individual costs of water injection and oil prices, generally a WOR of 100 is considered very high and likely not economically attractive to continue producing.

The graphs in Appendix A show that most of the 19 wells that have produced from the Muddy reached very high values of WOR at 100 or higher. The Muddy Unit 30-10 well had a final WOR of only two to three; however, the production data for this well extends over only 12 months, and the flat nature of the WOR vs cumulative oil curve indicates that the well was not experiencing any effective waterflood. This well has not produced since 2002, and was a water injector both before and after that period of production. The Martinez, F G 2 well, with final WOR in the range of 30 to 40, exhibits a flat WOR trend, also produced sporadically with only 12 months of production, and was subsequently converted to injection. The Martinez 3 well showed a final WOR of only 40-50, but the oil rate at this time was only about 1 BOPD or less. Additionally, production was being reported for both the Muddy and Niobrara at this time, and the allocation of the well's oil and water production between the Muddy and the Niobrara was likely based on extremely limited separate zone test data. Thus, the WOR calculation for the well is not considered reliable. All other Muddy producers on the list of 19, and the average WOR for the group, have reached WOR of 100 or higher. Based on the WOR vs cum. oil production analysis, all of these Muddy wells appear to have reached the end of their economic life due to the high water production.

Cash Flow Analysis

Cash flow analysis was performed on the nine wells on the list that have production after January 1st, 2020. The oil price forecast was based on an average of NYMEX future strip pricing contracts that traded approximately ten days prior to the effective date. The NYMEX future strip contained a twelve-year futures strip for oil and prices were held flat thereafter. These prices were adjusted by the differential of prices expected to be received at the wellhead for oil produced from the Muddy and Niobrara Formations. Based on WSP's experience in this area, the oil differential is estimated at 90.1 percent of West Texas Intermediate (WTI) crude oil spot prices. The unadjusted price forecast as of November 15th, 2023, is shown in Table 3 below. Other economic assumptions are provided in Table 4 below.

Table 3 Unadjusted NYMEX Crude Oil Future Price Forecasts

Year	NYMEX Crude Oil, $/Bbl	NYMEX HH Gas, $/MMBTU
2023	78.64	3.11
2024	76.67	3.35
2025	72.44	4.10
2026	69.11	4.16
2027	66.53	4.07
2028	64.31	3.96
2029	62.42	3.92
2030	60.63	3.79
2031	59.04	3.68
2032	57.70	3.67
2033	56.27	3.73
2034	55.61	3.81
2035	55.61	3.97

Table 4 Economic Assumptions

Parameter	**Value**
Operating Cost, $/Well/Month	$3,500
Oil Differentials, %	90.10%
Royalty Rate, %	12.5
Net Revenue Interest, %	87.5
Working Interest, %	100
Severance Tax Rate, %	3.7
Ad Valorem Tax, %	2.9

Although WSP has no data on the operating costs of these wells, experience with other wells in waterflood projects shows these costs can often be in the range of $5-$6,000 per well per month, or higher. A more conservative value of $3,500 per well per month because of the uncertainty associated with it. More information and examples of types of operating expenses typically associated with a waterflood are included in Appendix B.

Abandonment costs were not included. With the above assumptions incorporated, cash flow analysis was performed without an economic limit imposed on the cash flow to investigate the cash flow changes. Results are presented in Appendix C, and indicate that all nine of these wells are likely not performing at economic levels.

Active Injection Wells

As shown in Table 1, three of the wells are active injection wells. The usefulness of an injection well in a waterflood project is derived from the support that injection into that well provides for production in nearby wells. Figure 3 shows that for the three active injection wells on the list of 19, all the production wells near them are either already P&A'd, or on this list. Although the Muddy Sandstone Unit 19-9 well in Section 19 is somewhat near an active producer, another active injector is located between the 19-9 and the producer which can effectively support the production. Thus, these three wells would be considered to be not useful.

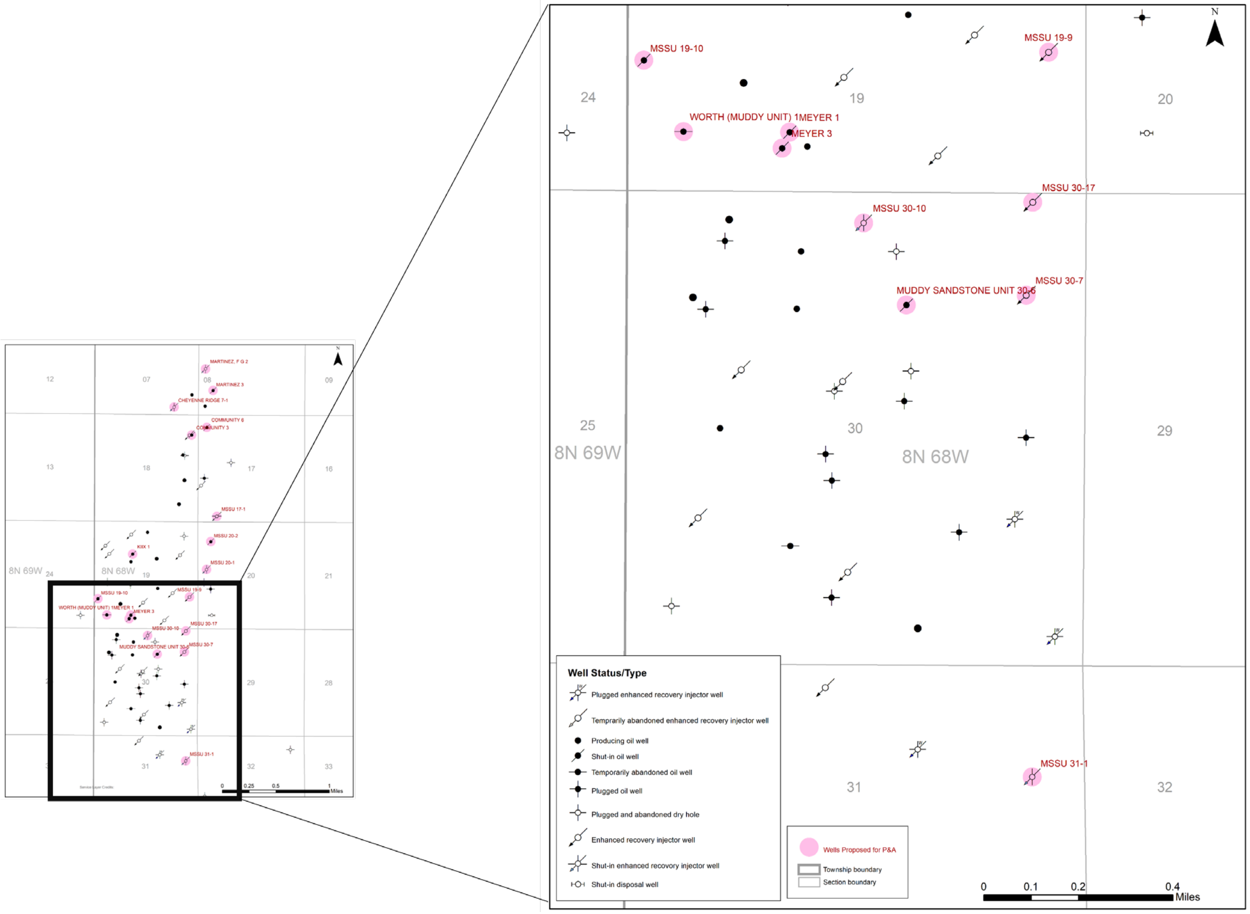

Figure 3 Expanded Map showing Active Injection Wells

Conclusions

Our analysis has resulted in the following conclusions:

1. None of the twenty wells on the list had production greater than 2 BOEPD for any of the three previous 12-month periods.
2. Economic analysis of the nine wells with production in the past three years indicates that none of them are likely generating any material revenue above the costs of royalties, production taxes, operating and maintenance costs.
3. The WOR performance of the Muddy wells on the list indicates that the effective life of the waterflood has been reached.
4. No apparent upside potential exists for refracturing or recompletion of any of these wells.
5. The three active injection wells have no active producing wells in the vicinity except for producers on this list or supported by closer injectors.
6. All other wells on the list have been inactive for some time.

7. In my opinion, all of the 19 wells on the list are no longer used or useful.

Please advise if we can provide additional information regarding this matter. We welcome the opportunity to be of service to you and look forward to your response.

Regards,

WSP

COLORADO REGISTERED
LETHA CHAPMAN LENCIONI
29506
PROFESSIONAL ENGINEER

Letha C. Lencioni, P.E.
Vice-President, Chief Petroleum Engineer
Registered Petroleum Engineer
State of Colorado #29506

APPENDIX A
Water-Oil-Ratio vs Cumulative Oil Production Graphs

Notes for all graphs in Appendix A:

The blue dots represent the ratio of water produced divided by oil produced per month, with the scale for these values shown on the right of the graph. It is generally difficult to produce economically at a WOR greater than 100.

Although monthly values are used, they are plotted not against time on the x-axis, but against the cumulative oil production. This is a typical diagnostic and forecasting plot for reservoir engineers to use in a waterflood, because a linear trend is expected on this plot. Several of the plots show linear trends marked with a red line.

The green connected points represent oil produced each month, with the scale on the left side of the graph. This curve is shown for reference and perspective.

APPENDIX B
Additional Information on Operating Costs

Oil and Gas Operating Costs – Waterflood

Below is a list of examples categories of costs commonly associated with waterflood operations.

- Electricity for running artificial lift, injection pumps, etc.
- If oilfield equipment is powered by produced gas instead of electricity, costs include dehydration of the gas and maintenance of the gas-powered engines.
- Salaries and benefits or contractual payments for pumpers (personnel who monitor and maintain or coordinate maintenance of oil and gas wells and surface facilities) and roustabouts (work crew for maintenance and repair), along with their vehicle expenses and gasoline costs.
- Oil field chemicals for various purposes, such as de-emulsifiers to aid in separation of oil and water, corrosion, scale inhibitors, etc.
- Maintenance of equipment, including artificial lift equipment (typically, pumping units and the engines to drive them, sucker rods, and downhole pumps), injection pumps, separation equipment, storage tanks, metering, surface flow lines and gathering systems, etc.
- Lease road and location maintenance.
- Various maintenance, testing, and reporting tasks for wells, equipment, and flow lines, as required by ECMC regulations.
- Various equipment repairs and well workovers.

List compiled from a combination of actual LOE statements for waterflood units and expert experience and knowledge. Costs from an actual waterflood unit in Kansas for 2022 with 37 active wells average $4,767 per well per month, excluding workover costs.

APPENDIX C
Cash Flow Analysis Summaries and Production Forecast Graphs

Notes for all graphs in Appendix B:

The connected green points represent monthly oil production versus time, with the scale in green on the left. The straight green line represents the fit based on recent production history and forecast of oil production into the future.

The blue triangles represent monthly water production vs. time, with the scale in blue on the right. These points are shown for reference.

Although the legend and scales show gas production and gas/oil ratio (GOR), no data are shown for these because no gas sales are reported for these wells.

MEYER
1
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DAKOTA
08/01/1999

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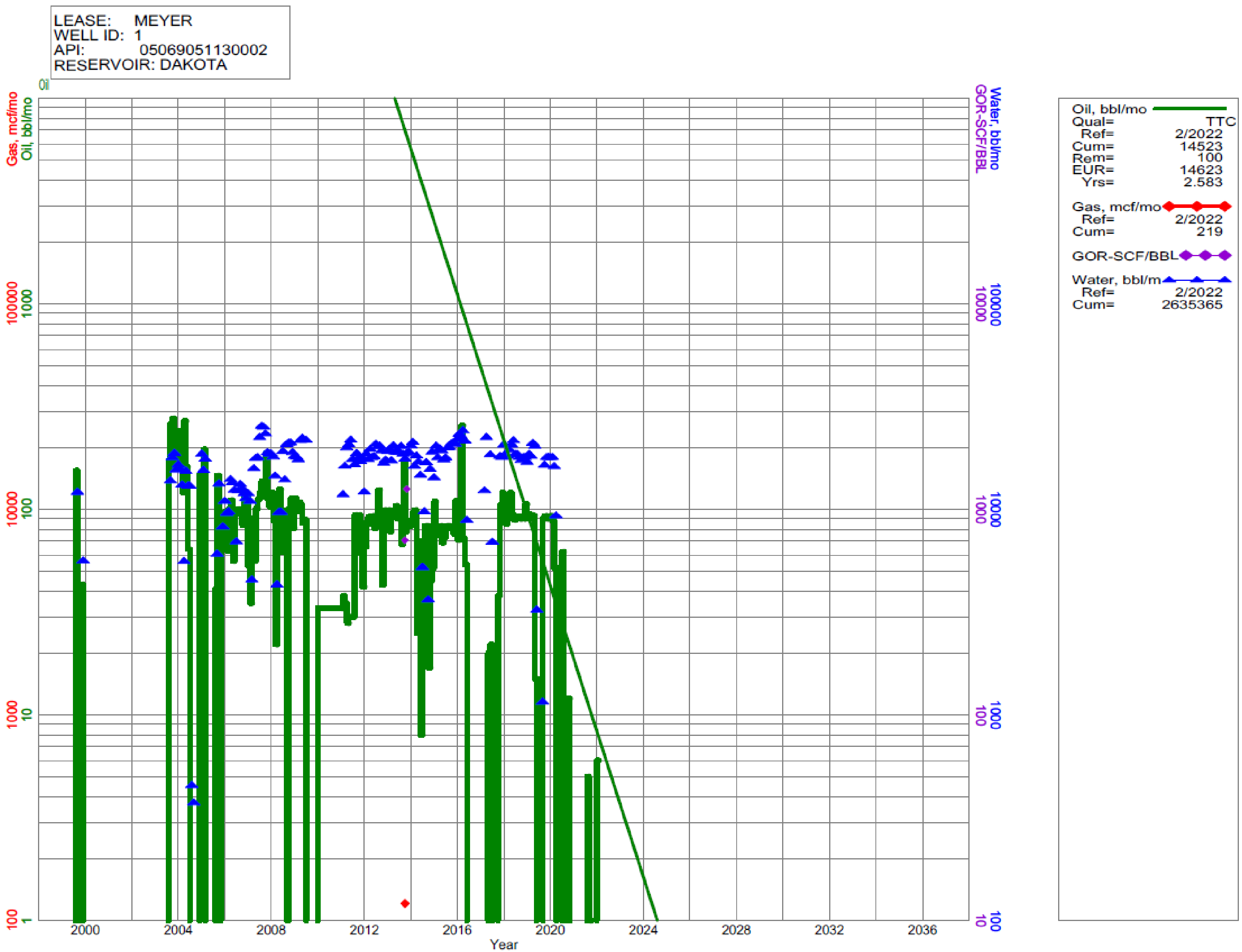
R E S E R V E S A N D E C O N O M I C S

AS OF DATE: 12/2023

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-2023	0.002	0.000	0.001	0.000	70.855	0.000	0.104	0.000	0.104
12-2024	0.010	0.000	0.008	0.000	69.080	0.000	0.580	0.000	0.580
12-2025									
12-2026									
12-2027									
12-2028									
12-2029									
12-2030									
12-2031									
12-2032									
12-2033									
12-2034									
12-2035									
12-2036									
12-2037									
S TOT	0.011	0.000	0.010	0.000	69.345	0.000	0.684	0.000	0.684
AFTER	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	0.011	0.000	0.010	0.000	69.345	0.000	0.684	0.000	0.684

--END-- MO-YEAR	AD VALOREM TAX -----M$----	PRODUCTION TAX -----M$----	DIRECT OPER EXPENSE -----M$----	INTEREST PAID -----M$----	CAPITAL REPAYMENT -----M$----	EQUITY INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-2023	0.003	0.004	3.500	0.000	0.000	0.000	-3.402	-3.402	-3.389
12-2024	0.017	0.021	28.000	0.000	0.000	0.000	-27.458	-30.861	-29.778
12-2025									
12-2026									
12-2027									
12-2028									
12-2029									
12-2030									
12-2031									
12-2032									
12-2033									
12-2034									
12-2035									
12-2036									
12-2037									
S TOT	0.020	0.025	31.500	0.000	0.000	0.000	-30.861	-30.861	-29.778
AFTER	0.000	0.000	0.000	0.000	0.000	0.000	0.000	-30.861	-29.778
TOTAL	0.020	0.025	31.500	0.000	0.000	0.000	-30.861	-30.861	-29.778

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	1.0	0.0	LIFE, YRS.	0.75	5.00	-30.301
GROSS ULT., MB & MMF	14.623	0.000	DISCOUNT %	10.00	10.00	-29.778
GROSS CUM., MB & MMF	14.612	0.000	UNDISCOUNTED PAYOUT, YRS.	0.75	20.00	-28.826
GROSS RES., MB & MMF	0.011	0.000	DISCOUNTED PAYOUT, YRS.	0.75	25.00	-28.391
NET RES., MB & MMF	0.010	0.000	UNDISCOUNTED NET/INVEST.	0.00	30.00	-27.980
NET REVENUE, M$	0.684	0.000	DISCOUNTED NET/INVEST.	0.00	35.00	-27.591
INITIAL PRICE, $	70.855	0.000	RATE-OF-RETURN, PCT.	0.00	45.00	-26.870
INITIAL N.I., PCT.	87.500	0.000	INITIAL W.I., PCT.	100.000	60.00	-25.911
					80.00	-24.814
					100.00	-23.876



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Oil, bbl/mo
Water, bbl/mo
GOR-SCF/BBL
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2004
2008
2012
2016
2020
2024
2028
2032
2036
Oil, bbl/mo
Qual= TTC
Ref= 2/2022
Cum= 14523
Rem= 100
EUR= 14623
Yrs= 2.583
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Water, bbl/m
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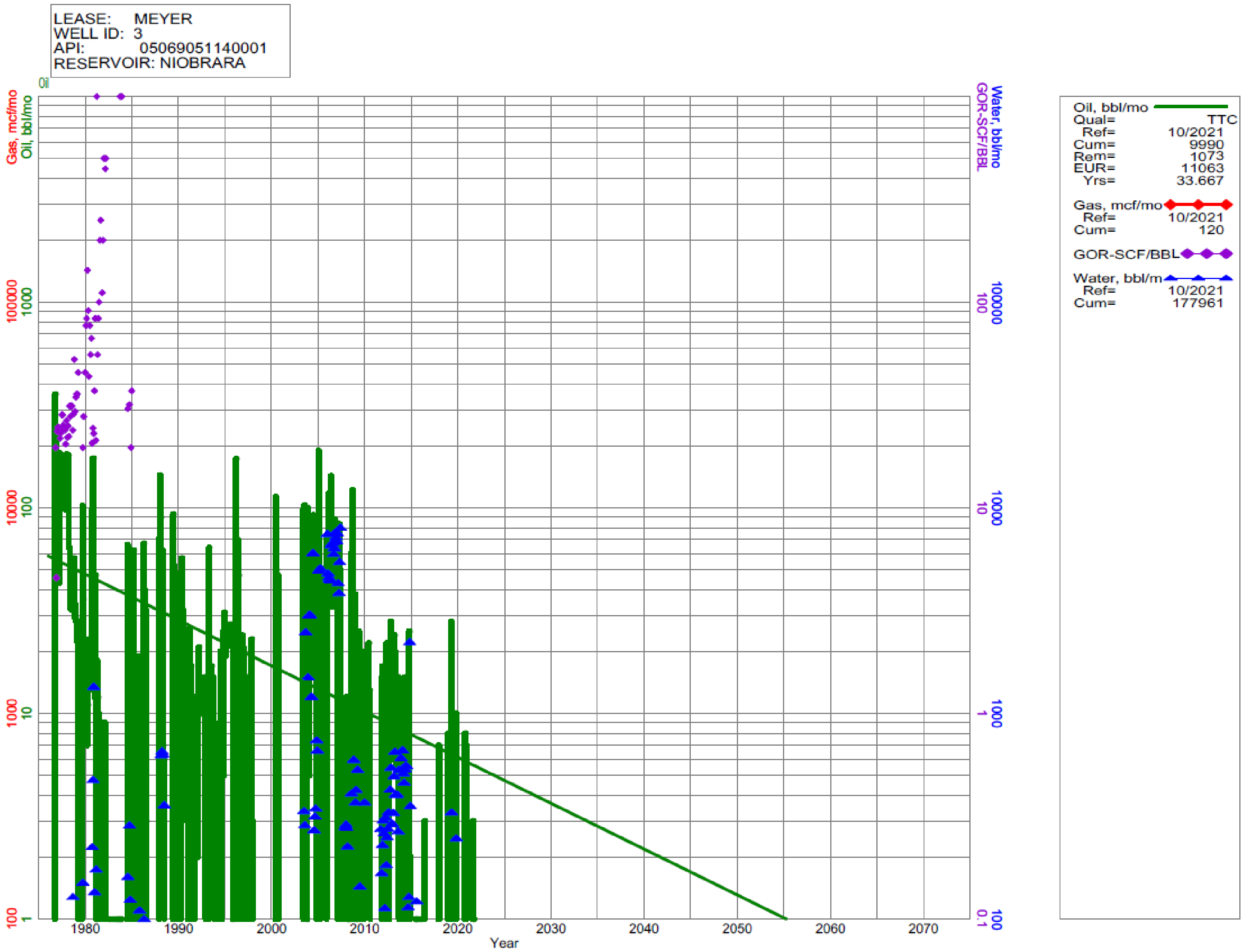
R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 12/2023

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-2023	0.005	0.000	0.004	0.000	70.855	0.000	0.309	0.000	0.309
12-2024	0.058	0.000	0.051	0.000	69.080	0.000	3.518	0.000	3.518
12-2025	0.055	0.000	0.048	0.000	65.268	0.000	3.157	0.000	3.157
12-2026	0.053	0.000	0.046	0.000	62.268	0.000	2.862	0.000	2.862
12-2027	0.050	0.000	0.044	0.000	59.944	0.000	2.617	0.000	2.617
12-2028	0.047	0.000	0.041	0.000	57.943	0.000	2.403	0.000	2.403
12-2029	0.045	0.000	0.039	0.000	56.240	0.000	2.216	0.000	2.216
12-2030	0.043	0.000	0.037	0.000	54.628	0.000	2.045	0.000	2.045
12-2031	0.041	0.000	0.036	0.000	53.195	0.000	1.892	0.000	1.892
12-2032	0.039	0.000	0.034	0.000	51.988	0.000	1.756	0.000	1.756
12-2033	0.037	0.000	0.032	0.000	50.699	0.000	1.627	0.000	1.627
12-2034	0.035	0.000	0.030	0.000	50.105	0.000	1.528	0.000	1.528
12-2035	0.033	0.000	0.029	0.000	50.105	0.000	1.451	0.000	1.451
12-2036	0.031	0.000	0.028	0.000	50.105	0.000	1.379	0.000	1.379
12-2037	0.030	0.000	0.026	0.000	50.105	0.000	1.310	0.000	1.310
S TOT	0.601	0.000	0.526	0.000	57.152	0.000	30.068	0.000	30.068
AFTER	0.261	0.000	0.228	0.000	50.105	0.000	11.438	0.000	11.438
TOTAL	0.862	0.000	0.754	0.000	55.019	0.000	41.506	0.000	41.506

--END-- MO-YEAR	AD VALOREM TAX -----M$----	PRODUCTION TAX -----M$----	DIRECT OPER EXPENSE -----M$----	INTEREST PAID -----M$----	CAPITAL REPAYMENT -----M$----	EQUITY INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-2023	0.009	0.011	3.500	0.000	0.000	0.000	-3.211	-3.211	-3.199
12-2024	0.102	0.130	42.000	0.000	0.000	0.000	-38.715	-41.926	-39.819
12-2025	0.092	0.117	42.000	0.000	0.000	0.000	-39.051	-80.977	-73.400
12-2026	0.083	0.106	42.000	0.000	0.000	0.000	-39.327	-120.304	-104.145
12-2027	0.076	0.097	42.000	0.000	0.000	0.000	-39.556	-159.860	-132.256
12-2028	0.070	0.089	42.000	0.000	0.000	0.000	-39.755	-199.615	-157.941
12-2029	0.064	0.082	42.000	0.000	0.000	0.000	-39.930	-239.545	-181.394
12-2030	0.059	0.076	42.000	0.000	0.000	0.000	-40.090	-279.636	-202.800
12-2031	0.055	0.070	42.000	0.000	0.000	0.000	-40.233	-319.869	-222.329
12-2032	0.051	0.065	42.000	0.000	0.000	0.000	-40.360	-360.228	-240.139
12-2033	0.047	0.060	42.000	0.000	0.000	0.000	-40.480	-400.709	-256.378
12-2034	0.044	0.057	42.000	0.000	0.000	0.000	-40.573	-441.282	-271.175
12-2035	0.042	0.054	42.000	0.000	0.000	0.000	-40.645	-481.927	-284.650
12-2036	0.040	0.051	42.000	0.000	0.000	0.000	-40.712	-522.639	-296.921
12-2037	0.038	0.048	42.000	0.000	0.000	0.000	-40.777	-563.416	-308.094
S TOT	0.872	1.113	591.500	0.000	0.000	0.000	-563.416	-563.416	-308.094
AFTER	0.332	0.423	504.000	0.000	0.000	0.000	-493.317	-1056.732	-384.748
TOTAL	1.203	1.536	1095.500	0.000	0.000	0.000	-1056.732	-1056.732	-384.748

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	1.0	0.0	LIFE, YRS.	26.08	5.00	-593.886
GROSS ULT., MB & MMF	10.990	0.000	DISCOUNT %	10.00	10.00	-384.748
GROSS CUM., MB & MMF	10.127	0.000	UNDISCOUNTED PAYOUT, YRS.	26.08	20.00	-215.360
GROSS RES., MB & MMF	0.862	0.000	DISCOUNTED PAYOUT, YRS.	26.08	25.00	-176.296
NET RES., MB & MMF	0.754	0.000	UNDISCOUNTED NET/INVEST.	0.00	30.00	-149.744
NET REVENUE, M$	41.506	0.000	DISCOUNTED NET/INVEST.	0.00	35.00	-130.631
INITIAL PRICE, $	70.855	0.000	RATE-OF-RETURN, PCT.	0.00	45.00	-105.033
INITIAL N.I., PCT.	87.500	0.000	INITIAL W.I., PCT.	100.000	60.00	-82.528
					80.00	-65.513
					100.00	-55.182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Water, bbl/mo
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Oil, bbl/mo
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EUR= 11063
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R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 12/2023

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-2023	0.001	0.000	0.001	0.000	70.855	0.000	0.079	0.000	0.079
12-2024	0.015	0.000	0.013	0.000	69.080	0.000	0.915	0.000	0.915
12-2025	0.015	0.000	0.013	0.000	65.268	0.000	0.838	0.000	0.838
12-2026	0.014	0.000	0.012	0.000	62.268	0.000	0.776	0.000	0.776
12-2027	0.014	0.000	0.012	0.000	59.944	0.000	0.724	0.000	0.724
12-2028	0.013	0.000	0.012	0.000	57.943	0.000	0.679	0.000	0.679
12-2029	0.013	0.000	0.011	0.000	56.240	0.000	0.639	0.000	0.639
12-2030	0.013	0.000	0.011	0.000	54.628	0.000	0.603	0.000	0.603
12-2031	0.012	0.000	0.011	0.000	53.195	0.000	0.569	0.000	0.569
12-2032	0.002	0.000	0.002	0.000	51.988	0.000	0.099	0.000	0.099
12-2033									
12-2034									
12-2035									
12-2036									
12-2037									
S TOT	0.113	0.000	0.098	0.000	60.137	0.000	5.922	0.000	5.922
AFTER	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	0.113	0.000	0.098	0.000	60.137	0.000	5.922	0.000	5.922

--END-- MO-YEAR	AD VALOREM TAX -----M$----	PRODUCTION TAX -----M$----	DIRECT OPER EXPENSE -----M$----	INTEREST PAID -----M$----	CAPITAL REPAYMENT -----M$----	EQUITY INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-2023	0.002	0.003	3.500	0.000	0.000	0.000	-3.426	-3.426	-3.412
12-2024	0.027	0.034	42.000	0.000	0.000	0.000	-41.146	-44.571	-42.333
12-2025	0.024	0.031	42.000	0.000	0.000	0.000	-41.217	-85.788	-77.776
12-2026	0.022	0.029	42.000	0.000	0.000	0.000	-41.275	-127.064	-110.043
12-2027	0.021	0.027	42.000	0.000	0.000	0.000	-41.323	-168.387	-139.411
12-2028	0.020	0.025	42.000	0.000	0.000	0.000	-41.366	-209.753	-166.137
12-2029	0.019	0.024	42.000	0.000	0.000	0.000	-41.403	-251.156	-190.454
12-2030	0.017	0.022	42.000	0.000	0.000	0.000	-41.437	-292.593	-212.579
12-2031	0.016	0.021	42.000	0.000	0.000	0.000	-41.468	-334.061	-232.709
12-2032	0.003	0.004	10.500	0.000	0.000	0.000	-10.408	-344.469	-237.468
12-2033									
12-2034									
12-2035									
12-2036									
12-2037									
S TOT	0.172	0.219	350.000	0.000	0.000	0.000	-344.469	-344.469	-237.468
AFTER	0.000	0.000	0.000	0.000	0.000	0.000	0.000	-344.469	-237.468
TOTAL	0.172	0.219	350.000	0.000	0.000	0.000	-344.469	-344.469	-237.468

	OIL	GAS
GROSS WELLS	1.0	0.0
GROSS ULT., MB & MMF	0.442	0.000
GROSS CUM., MB & MMF	0.329	0.000
GROSS RES., MB & MMF	0.113	0.000
NET RES., MB & MMF	0.098	0.000
NET REVENUE, M$	5.922	0.000
INITIAL PRICE, $	70.855	0.000
INITIAL N.I., PCT.	87.500	0.000

LIFE, YRS.	8.33
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	8.33
DISCOUNTED PAYOUT, YRS.	8.33
UNDISCOUNTED NET/INVEST.	0.00
DISCOUNTED NET/INVEST.	0.00
RATE-OF-RETURN, PCT.	0.00
INITIAL W.I., PCT.	100.000

P.W. %	P.W., M$
5.00	-282.922
10.00	-237.468
20.00	-176.658
25.00	-155.859
30.00	-139.240
35.00	-125.754
45.00	-105.402
60.00	-85.220
80.00	-68.648
100.00	-58.151

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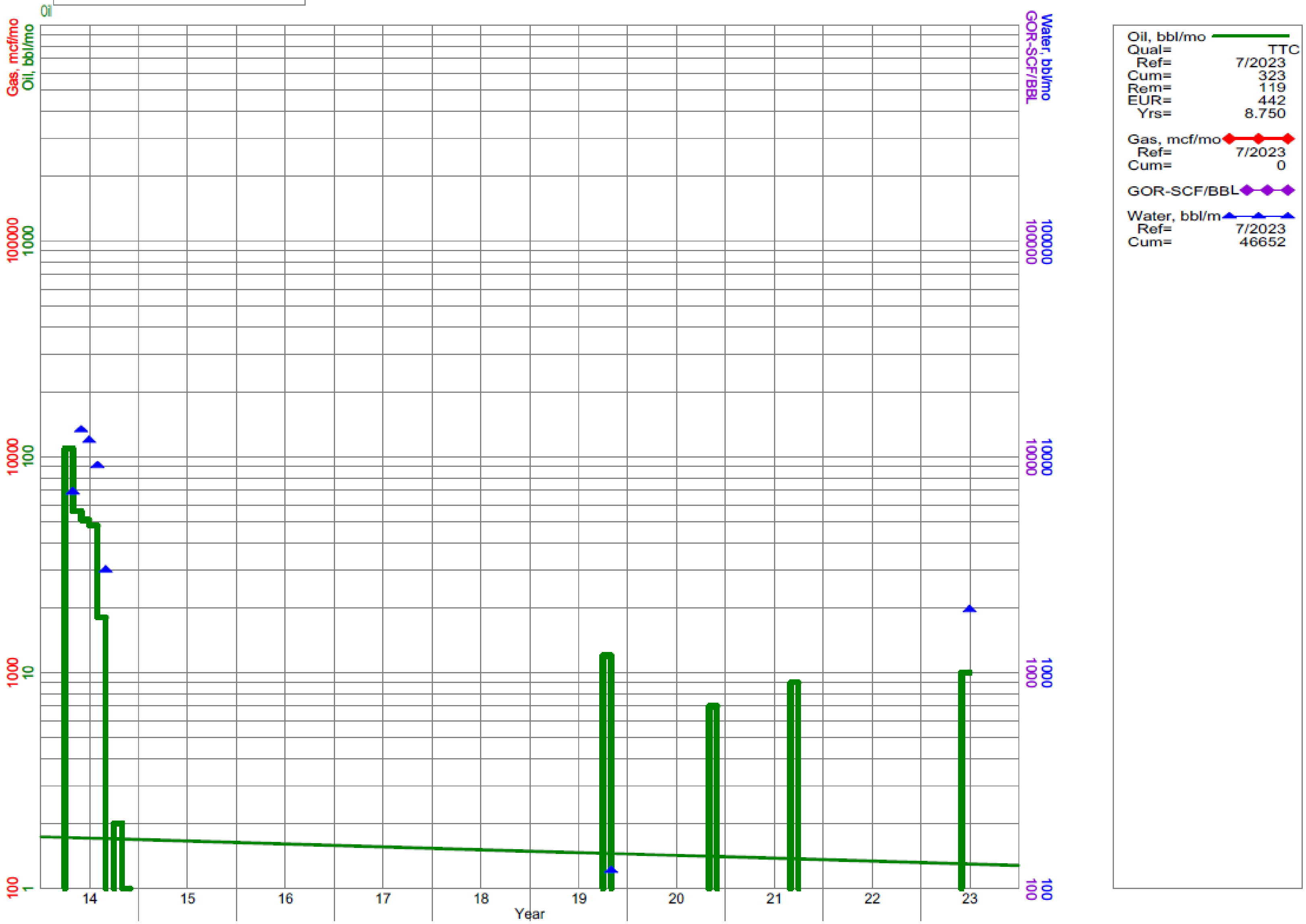

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R E S E R V E S A N D E C O N O M I C S

AS OF DATE: 12/2023

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-2023	0.060	0.000	0.052	0.000	70.855	0.000	3.692	0.000	3.692
12-2024	0.695	0.000	0.608	0.000	69.080	0.000	42.012	0.000	42.012
12-2025	0.660	0.000	0.578	0.000	65.268	0.000	37.710	0.000	37.710
12-2026	0.627	0.000	0.549	0.000	62.268	0.000	34.178	0.000	34.178
12-2027	0.596	0.000	0.521	0.000	59.944	0.000	31.257	0.000	31.257
12-2028	0.566	0.000	0.495	0.000	57.943	0.000	28.703	0.000	28.703
12-2029	0.538	0.000	0.471	0.000	56.240	0.000	26.466	0.000	26.466
12-2030	0.511	0.000	0.447	0.000	54.628	0.000	24.422	0.000	24.422
12-2031	0.485	0.000	0.425	0.000	53.195	0.000	22.593	0.000	22.593
12-2032	0.461	0.000	0.403	0.000	51.988	0.000	20.976	0.000	20.976
12-2033	0.438	0.000	0.383	0.000	50.699	0.000	19.433	0.000	19.433
12-2034	0.416	0.000	0.364	0.000	50.105	0.000	18.245	0.000	18.245
12-2035	0.395	0.000	0.346	0.000	50.105	0.000	17.333	0.000	17.333
12-2036	0.376	0.000	0.329	0.000	50.105	0.000	16.466	0.000	16.466
12-2037	0.357	0.000	0.312	0.000	50.105	0.000	15.643	0.000	15.643
S TOT	7.181	0.000	6.284	0.000	57.152	0.000	359.128	0.000	359.128
AFTER	3.116	0.000	2.727	0.000	50.105	0.000	136.611	0.000	136.611
TOTAL	10.297	0.000	9.010	0.000	55.019	0.000	495.738	0.000	495.738

--END-- MO-YEAR	AD VALOREM TAX -----M$----	PRODUCTION TAX -----M$----	DIRECT OPER EXPENSE -----M$----	INTEREST PAID -----M$----	CAPITAL REPAYMENT -----M$----	EQUITY INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-2023	0.107	0.137	3.500	0.000	0.000	0.000	-0.052	-0.052	-0.052
12-2024	1.218	1.554	42.000	0.000	0.000	0.000	-2.760	-2.812	-2.662
12-2025	1.093	1.395	42.000	0.000	0.000	0.000	-6.778	-9.590	-8.491
12-2026	0.991	1.265	42.000	0.000	0.000	0.000	-10.078	-19.668	-16.369
12-2027	0.906	1.156	42.000	0.000	0.000	0.000	-12.806	-32.474	-25.470
12-2028	0.832	1.062	42.000	0.000	0.000	0.000	-15.191	-47.665	-35.285
12-2029	0.767	0.979	42.000	0.000	0.000	0.000	-17.280	-64.945	-45.434
12-2030	0.708	0.904	42.000	0.000	0.000	0.000	-19.189	-84.134	-55.680
12-2031	0.655	0.836	42.000	0.000	0.000	0.000	-20.898	-105.032	-65.824
12-2032	0.608	0.776	42.000	0.000	0.000	0.000	-22.408	-127.441	-75.713
12-2033	0.563	0.719	42.000	0.000	0.000	0.000	-23.849	-151.290	-85.280
12-2034	0.529	0.675	42.000	0.000	0.000	0.000	-24.959	-176.249	-94.383
12-2035	0.502	0.641	42.000	0.000	0.000	0.000	-25.811	-202.060	-102.940
12-2036	0.477	0.609	42.000	0.000	0.000	0.000	-26.620	-228.681	-110.963
12-2037	0.453	0.579	42.000	0.000	0.000	0.000	-27.389	-256.070	-118.468
S TOT	10.410	13.288	591.500	0.000	0.000	0.000	-256.070	-256.070	-118.468
AFTER	3.960	5.055	504.000	0.000	0.000	0.000	-376.404	-632.474	-175.891
TOTAL	14.370	18.342	1095.500	0.000	0.000	0.000	-632.474	-632.474	-175.891

	OIL	GAS
GROSS WELLS	1.0	0.0
GROSS ULT., MB & MMF	44.603	0.000
GROSS CUM., MB & MMF	34.306	0.000
GROSS RES., MB & MMF	10.297	0.000
NET RES., MB & MMF	9.010	0.000
NET REVENUE, M$	495.738	0.000
INITIAL PRICE, $	70.855	0.000
INITIAL N.I., PCT.	87.500	0.000

LIFE, YRS.	26.08
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	26.08
DISCOUNTED PAYOUT, YRS.	26.08
UNDISCOUNTED NET/INVEST.	0.00
DISCOUNTED NET/INVEST.	0.00
RATE-OF-RETURN, PCT.	0.00
INITIAL W.I., PCT.	100.000

P.W. %	P.W., M$
5.00	-311.933
10.00	-175.891
20.00	-76.280
25.00	-56.092
30.00	-43.371
35.00	-34.839
45.00	-24.405
60.00	-16.359
80.00	-11.112
100.00	-8.330

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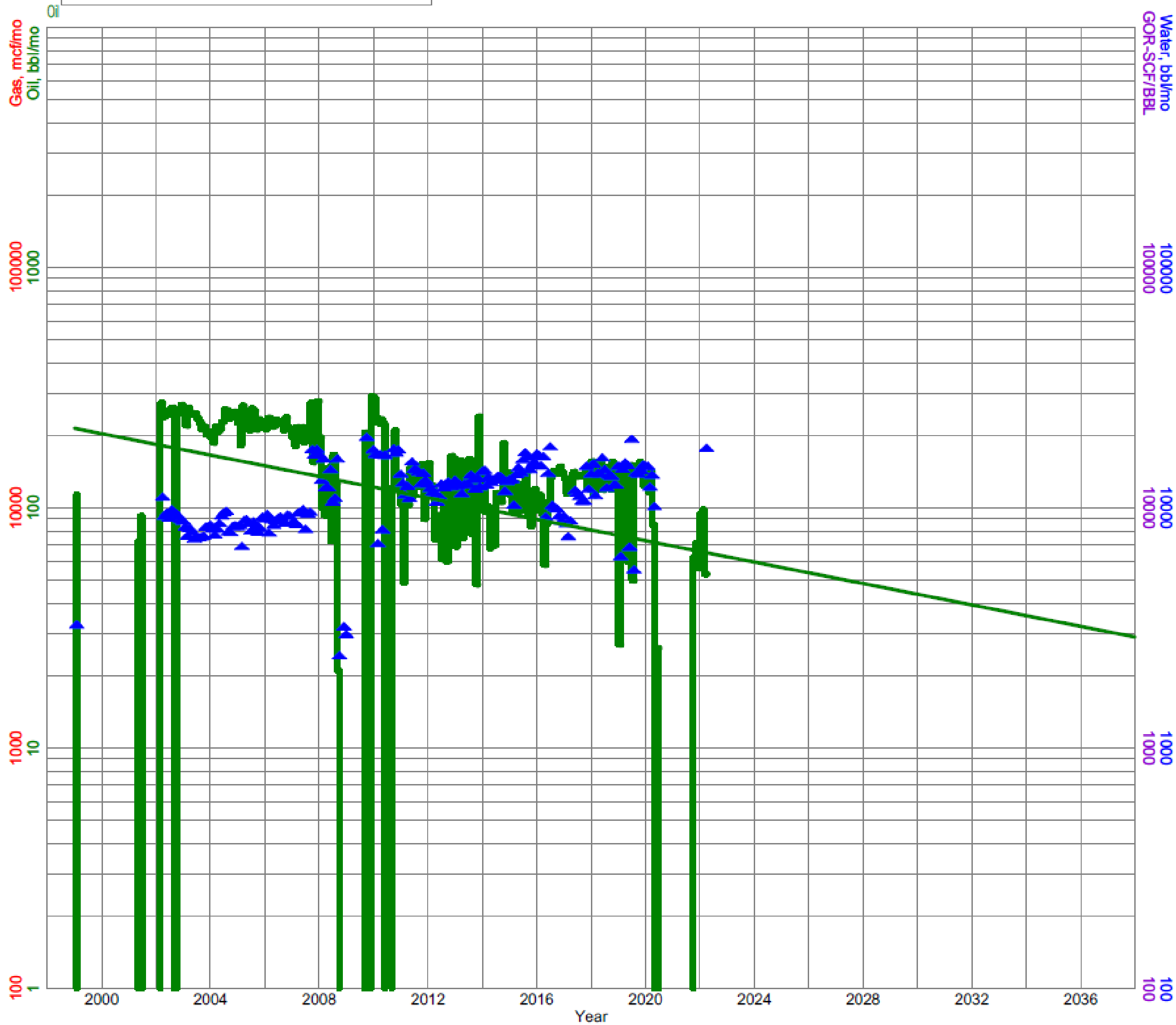
RESERVOIR:	MUDDY



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GOR-SCF/BBL	
Water, bbl/m	
Ref=	4/2022
Cum=	2354973

R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 12/2023

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-2023	0.028	0.000	0.024	0.000	70.855	0.000	1.719	0.000	1.719
12-2024	0.330	0.000	0.289	0.000	69.080	0.000	19.956	0.000	19.956
12-2025	0.325	0.000	0.285	0.000	65.268	0.000	18.580	0.000	18.580
12-2026	0.321	0.000	0.281	0.000	62.268	0.000	17.467	0.000	17.467
12-2027	0.316	0.000	0.276	0.000	59.944	0.000	16.570	0.000	16.570
12-2028	0.311	0.000	0.272	0.000	57.943	0.000	15.784	0.000	15.784
12-2029	0.307	0.000	0.268	0.000	56.240	0.000	15.097	0.000	15.097
12-2030	0.302	0.000	0.265	0.000	54.628	0.000	14.450	0.000	14.450
12-2031	0.298	0.000	0.261	0.000	53.195	0.000	13.866	0.000	13.866
12-2032	0.294	0.000	0.257	0.000	51.988	0.000	13.354	0.000	13.354
12-2033	0.289	0.000	0.253	0.000	50.699	0.000	12.834	0.000	12.834
12-2034	0.285	0.000	0.249	0.000	50.105	0.000	12.498	0.000	12.498
12-2035	0.281	0.000	0.246	0.000	50.105	0.000	12.316	0.000	12.316
12-2036	0.277	0.000	0.242	0.000	50.105	0.000	12.137	0.000	12.137
12-2037	0.273	0.000	0.239	0.000	50.105	0.000	11.960	0.000	11.960
S TOT	4.237	0.000	3.707	0.000	56.269	0.000	208.589	0.000	208.589
AFTER	2.980	0.000	2.607	0.000	50.105	0.000	130.626	0.000	130.626
TOTAL	7.216	0.000	6.314	0.000	53.724	0.000	339.215	0.000	339.215

--END-- MO-YEAR	AD VALOREM TAX -----M$----	PRODUCTION TAX -----M$----	DIRECT OPER EXPENSE -----M$----	INTEREST PAID -----M$----	CAPITAL REPAYMENT -----M$----	EQUITY INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-2023	0.050	0.064	3.500	0.000	0.000	0.000	-1.894	-1.894	-1.887
12-2024	0.578	0.738	42.000	0.000	0.000	0.000	-23.361	-25.255	-23.985
12-2025	0.539	0.687	42.000	0.000	0.000	0.000	-24.646	-49.902	-45.178
12-2026	0.506	0.646	42.000	0.000	0.000	0.000	-25.685	-75.587	-65.258
12-2027	0.480	0.613	42.000	0.000	0.000	0.000	-26.523	-102.110	-84.107
12-2028	0.458	0.584	42.000	0.000	0.000	0.000	-27.257	-129.367	-101.718
12-2029	0.438	0.559	42.000	0.000	0.000	0.000	-27.899	-157.266	-118.104
12-2030	0.419	0.535	42.000	0.000	0.000	0.000	-28.503	-185.770	-133.323
12-2031	0.402	0.513	42.000	0.000	0.000	0.000	-29.049	-214.818	-147.424
12-2032	0.387	0.494	42.000	0.000	0.000	0.000	-29.527	-244.345	-160.453
12-2033	0.372	0.475	42.000	0.000	0.000	0.000	-30.013	-274.358	-172.493
12-2034	0.362	0.462	42.000	0.000	0.000	0.000	-30.327	-304.685	-183.553
12-2035	0.357	0.456	42.000	0.000	0.000	0.000	-30.497	-335.182	-193.664
12-2036	0.352	0.449	42.000	0.000	0.000	0.000	-30.664	-365.846	-202.906
12-2037	0.347	0.443	42.000	0.000	0.000	0.000	-30.829	-396.675	-211.354
S TOT	6.046	7.718	591.500	0.000	0.000	0.000	-396.675	-396.675	-211.354
AFTER	3.786	4.833	504.000	0.000	0.000	0.000	-381.993	-778.668	-270.473
TOTAL	9.833	12.551	1095.500	0.000	0.000	0.000	-778.668	-778.668	-270.473

	OIL	GAS
GROSS WELLS	1.0	0.0
GROSS ULT., MB & MMF	11.089	0.000
GROSS CUM., MB & MMF	3.873	0.000
GROSS RES., MB & MMF	7.216	0.000
NET RES., MB & MMF	6.314	0.000
NET REVENUE, M$	339.215	0.000
INITIAL PRICE, $	70.855	0.000
INITIAL N.I., PCT.	87.500	0.000

LIFE, YRS.	26.08
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	26.08
DISCOUNTED PAYOUT, YRS.	26.08
UNDISCOUNTED NET/INVEST.	0.00
DISCOUNTED NET/INVEST.	0.00
RATE-OF-RETURN, PCT.	0.00
INITIAL W.I., PCT.	100.000

P.W. %	P.W., M$
5.00	-427.275
10.00	-270.473
20.00	-145.902
25.00	-117.830
30.00	-98.991
35.00	-85.584
45.00	-67.876
60.00	-52.594
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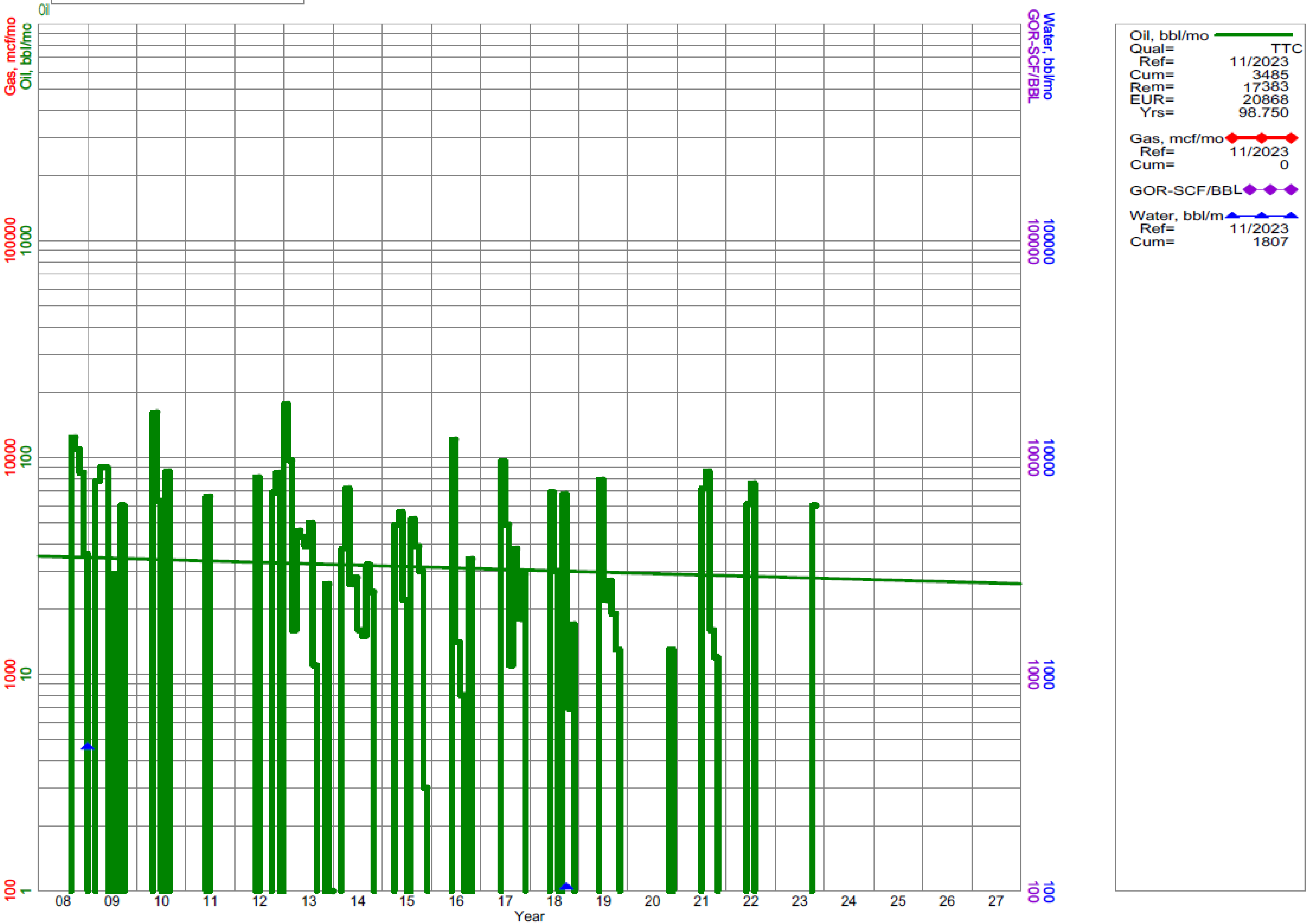

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20-2
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04/01/2008

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R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 12/2023

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-2023									
12-2024									
12-2025									
12-2026									
12-2027									
12-2028									
12-2029									
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12-2031									
12-2032									
12-2033									
12-2034									
12-2035									
12-2036									
12-2037									
S TOT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
AFTER	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

--END-- MO-YEAR	AD VALOREM TAX -----M$----	PRODUCTION TAX -----M$----	DIRECT OPER EXPENSE -----M$----	INTEREST PAID -----M$----	CAPITAL REPAYMENT -----M$----	EQUITY INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-2023									
12-2024									
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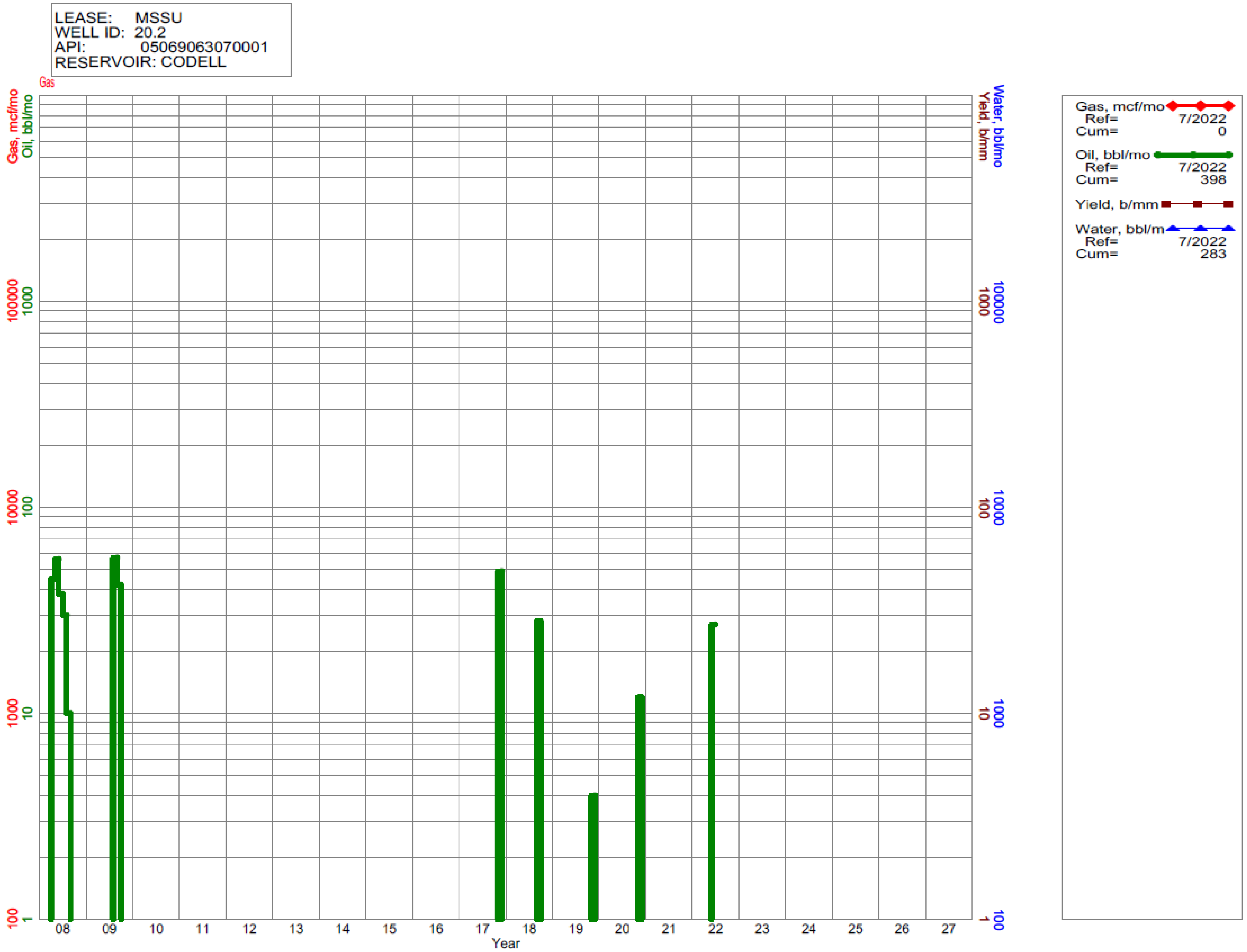
12-2034									
12-2035									
12-2036									
12-2037									
S TOT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
AFTER	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	1.0	0.0	LIFE, YRS.	0.00	5.00	0.000
GROSS ULT., MB & MMF	0.398	0.000	DISCOUNT %	10.00	10.00	0.000
GROSS CUM., MB & MMF	0.398	0.000	UNDISCOUNTED PAYOUT, YRS.	0.00	20.00	0.000
GROSS RES., MB & MMF	0.000	0.000	DISCOUNTED PAYOUT, YRS.	0.00	25.00	0.000
NET RES., MB & MMF	0.000	0.000	UNDISCOUNTED NET/INVEST.	0.00	30.00	0.000
NET REVENUE, M$	0.000	0.000	DISCOUNTED NET/INVEST.	0.00	35.00	0.000
INITIAL PRICE, $	70.855	0.000	RATE-OF-RETURN, PCT.	0.00	45.00	0.000
INITIAL N.I., PCT.	0.000	0.000	INITIAL W.I., PCT.	0.000	60.00	0.000
					80.00	0.000
					100.00	0.000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Water, bbl/mo
Yield, b/mm
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09
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Cum= 398
Yield, b/mm
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0034

CHEYENNE RIDGE
7-1
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NIOBRARA
04/01/2011

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R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 12/2023

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-2023	0.004	0.000	0.003	0.000	70.855	0.000	0.234	0.000	0.234
12-2024	0.044	0.000	0.039	0.000	69.080	0.000	2.682	0.000	2.682
12-2025	0.043	0.000	0.037	0.000	65.268	0.000	2.433	0.000	2.433
12-2026	0.041	0.000	0.036	0.000	62.268	0.000	2.228	0.000	2.228
12-2027	0.039	0.000	0.034	0.000	59.944	0.000	2.059	0.000	2.059
12-2028	0.038	0.000	0.033	0.000	57.943	0.000	1.911	0.000	1.911
12-2029	0.036	0.000	0.032	0.000	56.240	0.000	1.781	0.000	1.781
12-2030	0.035	0.000	0.030	0.000	54.628	0.000	1.660	0.000	1.660
12-2031	0.033	0.000	0.029	0.000	53.195	0.000	1.552	0.000	1.552
12-2032	0.032	0.000	0.028	0.000	51.988	0.000	1.456	0.000	1.456
12-2033	0.031	0.000	0.027	0.000	50.699	0.000	1.363	0.000	1.363
12-2034	0.030	0.000	0.026	0.000	50.105	0.000	1.294	0.000	1.294
12-2035	0.028	0.000	0.025	0.000	50.105	0.000	1.242	0.000	1.242
12-2036	0.027	0.000	0.024	0.000	50.105	0.000	1.192	0.000	1.192
12-2037	0.026	0.000	0.023	0.000	50.105	0.000	1.144	0.000	1.144
S TOT	0.487	0.000	0.426	0.000	56.898	0.000	24.234	0.000	24.234
AFTER	0.243	0.000	0.212	0.000	50.105	0.000	10.637	0.000	10.637
TOTAL	0.729	0.000	0.638	0.000	54.638	0.000	34.871	0.000	34.871

--END-- MO-YEAR	AD VALOREM TAX -----M$----	PRODUCTION TAX -----M$----	DIRECT OPER EXPENSE -----M$----	INTEREST PAID -----M$----	CAPITAL REPAYMENT -----M$----	EQUITY INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-2023	0.007	0.009	3.500	0.000	0.000	0.000	-3.281	-3.281	-3.268
12-2024	0.078	0.099	42.000	0.000	0.000	0.000	-39.495	-42.776	-40.627
12-2025	0.071	0.090	42.000	0.000	0.000	0.000	-39.727	-82.503	-74.789
12-2026	0.065	0.082	42.000	0.000	0.000	0.000	-39.919	-122.422	-105.996
12-2027	0.060	0.076	42.000	0.000	0.000	0.000	-40.076	-162.498	-134.478
12-2028	0.055	0.071	42.000	0.000	0.000	0.000	-40.215	-202.713	-160.460
12-2029	0.052	0.066	42.000	0.000	0.000	0.000	-40.337	-243.050	-184.151
12-2030	0.048	0.061	42.000	0.000	0.000	0.000	-40.449	-283.499	-205.749
12-2031	0.045	0.057	42.000	0.000	0.000	0.000	-40.550	-324.049	-225.432
12-2032	0.042	0.054	42.000	0.000	0.000	0.000	-40.640	-364.689	-243.366
12-2033	0.040	0.050	42.000	0.000	0.000	0.000	-40.727	-405.416	-259.704
12-2034	0.037	0.048	42.000	0.000	0.000	0.000	-40.792	-446.208	-274.580
12-2035	0.036	0.046	42.000	0.000	0.000	0.000	-40.840	-487.048	-288.120
12-2036	0.035	0.044	42.000	0.000	0.000	0.000	-40.887	-527.934	-300.443
12-2037	0.033	0.042	42.000	0.000	0.000	0.000	-40.931	-568.865	-311.658
S TOT	0.702	0.897	591.500	0.000	0.000	0.000	-568.865	-568.865	-311.658
AFTER	0.308	0.394	504.000	0.000	0.000	0.000	-494.065	-1062.930	-388.454
TOTAL	1.011	1.290	1095.500	0.000	0.000	0.000	-1062.930	-1062.930	-388.454

	OIL	GAS
GROSS WELLS	1.0	0.0
GROSS ULT., MB & MMF	2.580	0.000
GROSS CUM., MB & MMF	1.851	0.000
GROSS RES., MB & MMF	0.729	0.000
NET RES., MB & MMF	0.638	0.000
NET REVENUE, M$	34.871	0.000
INITIAL PRICE, $	70.855	0.000
INITIAL N.I., PCT.	87.500	0.000

LIFE, YRS.	26.08
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	26.08
DISCOUNTED PAYOUT, YRS.	26.08
UNDISCOUNTED NET/INVEST.	0.00
DISCOUNTED NET/INVEST.	0.00
RATE-OF-RETURN, PCT.	0.00
INITIAL W.I., PCT.	100.000

P.W. %	P.W., M$
5.00	-598.525
10.00	-388.454
20.00	-218.031
25.00	-178.654
30.00	-151.864
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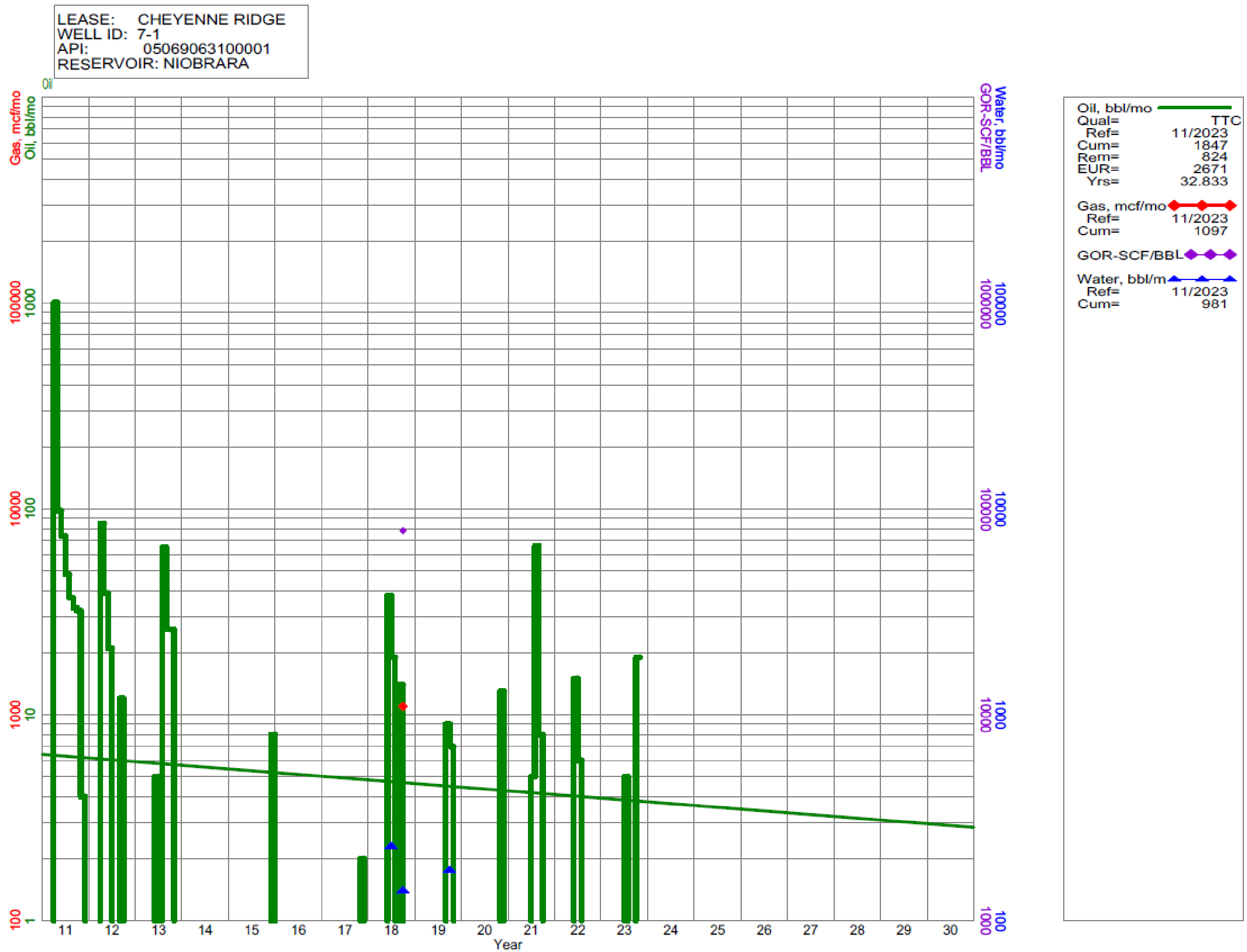
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Water, bbl/mo
GOR-SCF/BBL
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Oil, bbl/mo
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MUDDY
09/01/2007

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R E S E R V E S A N D E C O N O M I C S

AS OF DATE: 12/2023

--END-- MO-YEAR -------	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
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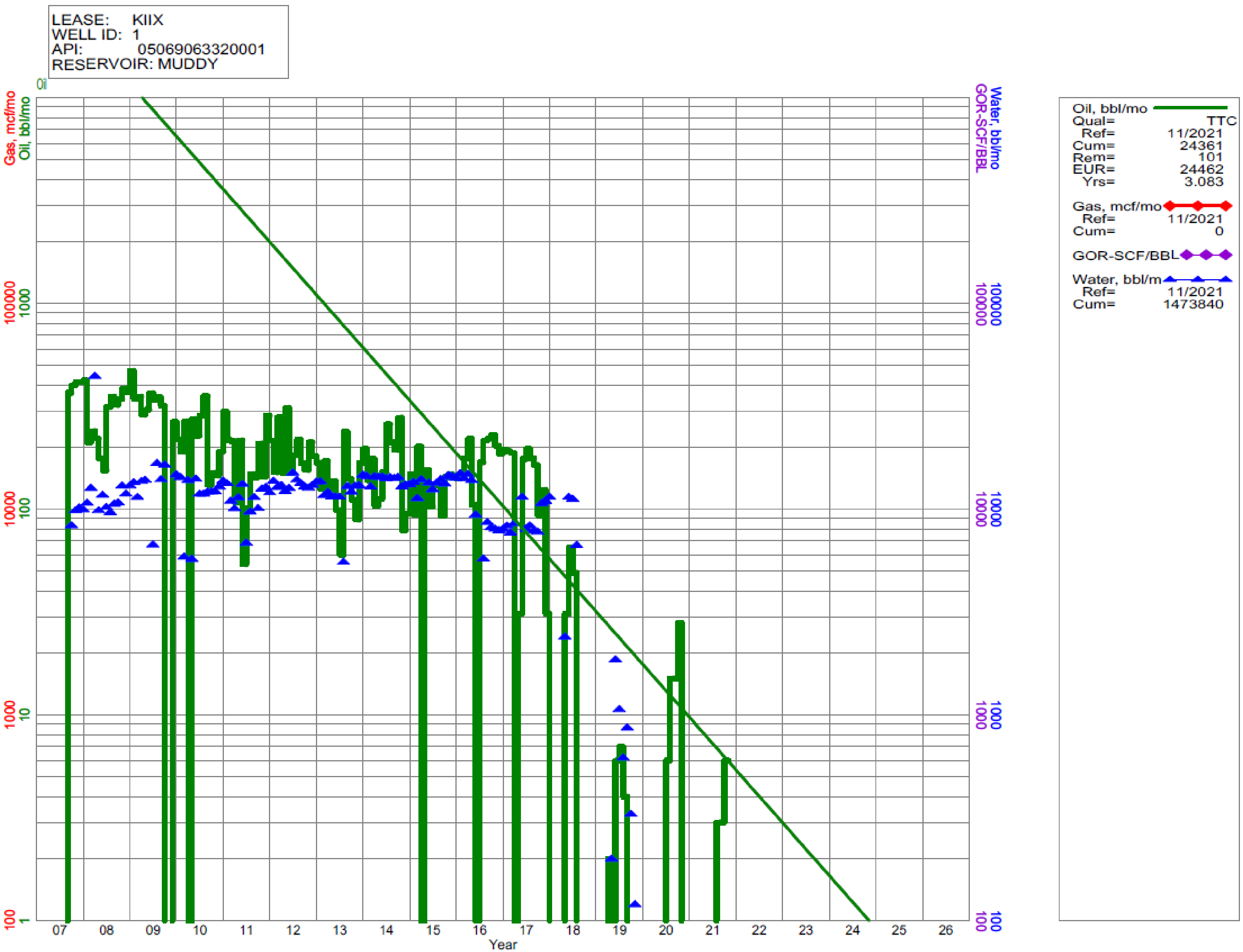
S TOT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
AFTER	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

--END-- MO-YEAR -------	AD VALOREM TAX -----M$----	PRODUCTION TAX -----M$----	DIRECT OPER EXPENSE -----M$----	INTEREST PAID -----M$----	CAPITAL REPAYMENT -----M$----	EQUITY INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-2023									
12-2024									
12-2025									
12-2026									
12-2027									
12-2028									
12-2029									
12-2030									
12-2031									
12-2032									
12-2033									
12-2034									
12-2035									
12-2036									
12-2037									
S TOT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
AFTER	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	1.0	0.0	LIFE, YRS.	0.00	5.00	0.000
GROSS ULT., MB & MMF	24.385	0.000	DISCOUNT %	10.00	10.00	0.000
GROSS CUM., MB & MMF	24.385	0.000	UNDISCOUNTED PAYOUT, YRS.	0.00	20.00	0.000
GROSS RES., MB & MMF	0.000	0.000	DISCOUNTED PAYOUT, YRS.	0.00	25.00	0.000
NET RES., MB & MMF	0.000	0.000	UNDISCOUNTED NET/INVEST.	0.00	30.00	0.000
NET REVENUE, M$	0.000	0.000	DISCOUNTED NET/INVEST.	0.00	35.00	0.000
INITIAL PRICE, $	70.855	0.000	RATE-OF-RETURN, PCT.	0.00	45.00	0.000
INITIAL N.I., PCT.	87.500	0.000	INITIAL W.I., PCT.	100.000	60.00	0.000
					80.00	0.000
					100.00	0.000


LEASE: KIIX
WELL ID: 1
API: 05069063320001
RESERVOIR: MUDDY
Gas, mcf/mo
Oil, bbl/mo
Water, bbl/mo
GOR-SCF/BBL
Year
Oil, bbl/mo
Qual= TTC
Ref= 11/2021
Cum= 24361
Rem= 101
EUR= 24462
Yrs= 3.083
Gas, mcf/mo
Ref= 11/2021
Cum= 0
GOR-SCF/BBL
Water, bbl/m
Ref= 11/2021
Cum= 1473840

MARTINEZ
3
05069063990001
NIOBRARA
08/01/2013

DATE : 12/30/2023
TIME : 15:39:00
DBS : WSP
SETTINGS : SETDATA
SCENARIO : DEFAULT

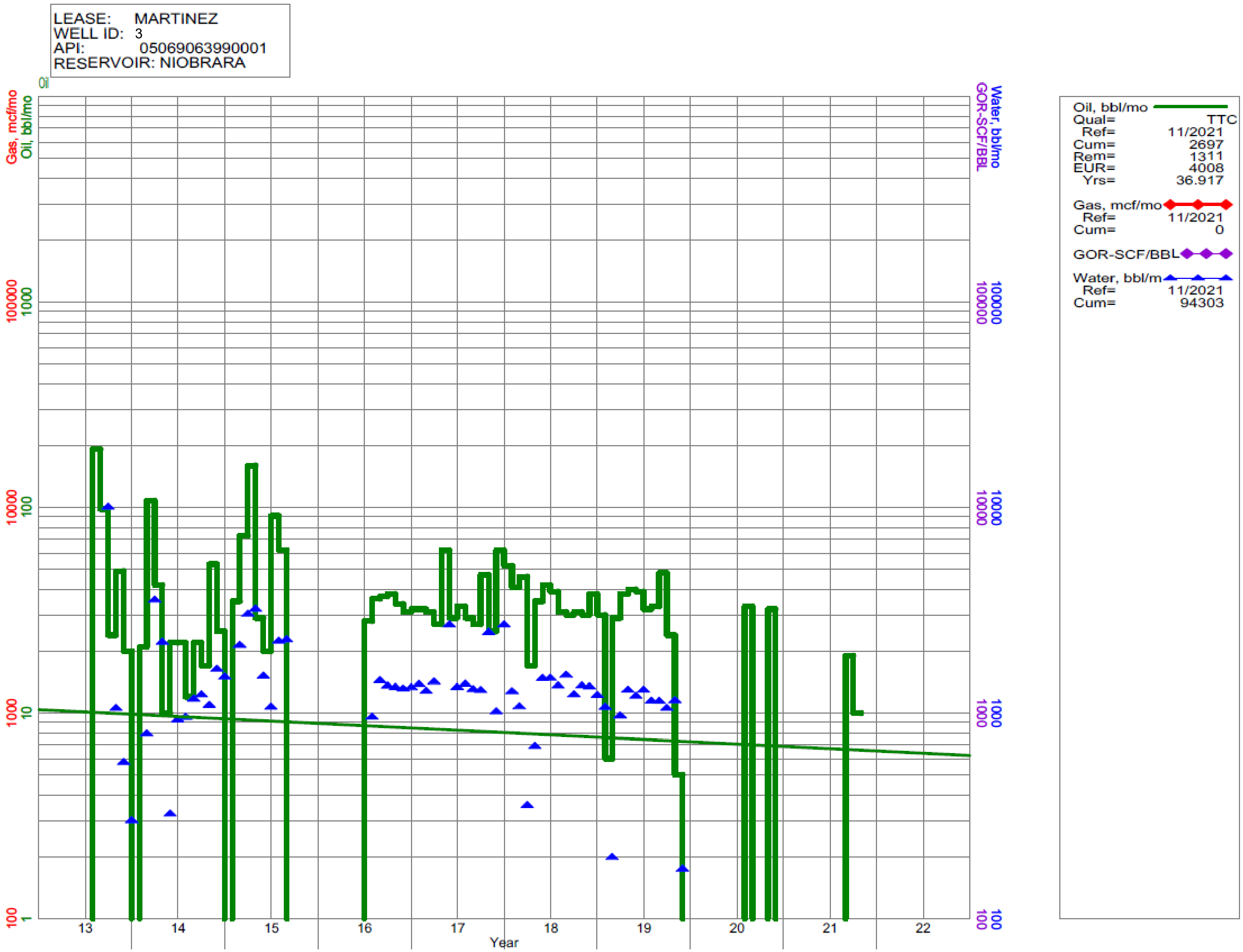
R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 12/2023

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-2023	0.006	0.000	0.005	0.000	70.855	0.000	0.367	0.000	0.367
12-2024	0.069	0.000	0.060	0.000	69.080	0.000	4.176	0.000	4.176
12-2025	0.066	0.000	0.057	0.000	65.268	0.000	3.748	0.000	3.748
12-2026	0.062	0.000	0.055	0.000	62.268	0.000	3.397	0.000	3.397
12-2027	0.059	0.000	0.052	0.000	59.944	0.000	3.107	0.000	3.107
12-2028	0.056	0.000	0.049	0.000	57.943	0.000	2.853	0.000	2.853
12-2029	0.053	0.000	0.047	0.000	56.240	0.000	2.631	0.000	2.631
12-2030	0.051	0.000	0.044	0.000	54.628	0.000	2.427	0.000	2.427
12-2031	0.048	0.000	0.042	0.000	53.195	0.000	2.246	0.000	2.246
12-2032	0.046	0.000	0.040	0.000	51.988	0.000	2.085	0.000	2.085
12-2033	0.044	0.000	0.038	0.000	50.699	0.000	1.931	0.000	1.931
12-2034	0.041	0.000	0.036	0.000	50.105	0.000	1.813	0.000	1.813
12-2035	0.039	0.000	0.034	0.000	50.105	0.000	1.723	0.000	1.723
12-2036	0.037	0.000	0.033	0.000	50.105	0.000	1.637	0.000	1.637
12-2037	0.035	0.000	0.031	0.000	50.105	0.000	1.555	0.000	1.555
S TOT	0.714	0.000	0.625	0.000	57.152	0.000	35.694	0.000	35.694
AFTER	0.310	0.000	0.271	0.000	50.105	0.000	13.578	0.000	13.578
TOTAL	1.023	0.000	0.896	0.000	55.019	0.000	49.272	0.000	49.272

--END-- MO-YEAR	AD VALOREM TAX -----M$----	PRODUCTION TAX -----M$----	DIRECT OPER EXPENSE -----M$----	INTEREST PAID -----M$----	CAPITAL REPAYMENT -----M$----	EQUITY INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-2023	0.011	0.014	3.500	0.000	0.000	0.000	-3.157	-3.157	-3.145
12-2024	0.121	0.155	42.000	0.000	0.000	0.000	-38.100	-41.257	-39.184
12-2025	0.109	0.139	42.000	0.000	0.000	0.000	-38.499	-79.756	-72.291
12-2026	0.098	0.126	42.000	0.000	0.000	0.000	-38.827	-118.584	-102.644
12-2027	0.090	0.115	42.000	0.000	0.000	0.000	-39.098	-157.682	-130.431
12-2028	0.083	0.106	42.000	0.000	0.000	0.000	-39.335	-197.017	-155.844
12-2029	0.076	0.097	42.000	0.000	0.000	0.000	-39.543	-236.560	-179.069
12-2030	0.070	0.090	42.000	0.000	0.000	0.000	-39.733	-276.293	-200.285
12-2031	0.065	0.083	42.000	0.000	0.000	0.000	-39.903	-316.196	-219.654
12-2032	0.060	0.077	42.000	0.000	0.000	0.000	-40.053	-356.249	-237.328
12-2033	0.056	0.071	42.000	0.000	0.000	0.000	-40.196	-396.445	-253.453
12-2034	0.053	0.067	42.000	0.000	0.000	0.000	-40.306	-436.751	-268.153
12-2035	0.050	0.064	42.000	0.000	0.000	0.000	-40.391	-477.142	-281.544
12-2036	0.047	0.061	42.000	0.000	0.000	0.000	-40.471	-517.613	-293.742
12-2037	0.045	0.058	42.000	0.000	0.000	0.000	-40.548	-558.161	-304.852
S TOT	1.035	1.321	591.500	0.000	0.000	0.000	-558.161	-558.161	-304.852
AFTER	0.394	0.502	504.000	0.000	0.000	0.000	-491.318	-1049.479	-381.178
TOTAL	1.428	1.823	1095.500	0.000	0.000	0.000	-1049.479	-1049.479	-381.178

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	1.0	0.0	LIFE, YRS.	26.08	5.00	-589.066
GROSS ULT., MB & MMF	3.877	0.000	DISCOUNT %	10.00	10.00	-381.178
GROSS CUM., MB & MMF	2.853	0.000	UNDISCOUNTED PAYOUT, YRS.	26.08	20.00	-212.982
GROSS RES., MB & MMF	1.023	0.000	DISCOUNTED PAYOUT, YRS.	26.08	25.00	-174.241
NET RES., MB & MMF	0.896	0.000	UNDISCOUNTED NET/INVEST.	0.00	30.00	-147.925
NET REVENUE, M$	49.272	0.000	DISCOUNTED NET/INVEST.	0.00	35.00	-128.994
INITIAL PRICE, $	70.855	0.000	RATE-OF-RETURN, PCT.	0.00	45.00	-103.655
INITIAL N.I., PCT.	87.500	0.000	INITIAL W.I., PCT.	100.000	60.00	-81.397
					80.00	-64.583
					100.00	-54.381



LEASE: MARTINEZ
WELL ID: 3
API: 05069063990001
RESERVOIR: NIOBRARA
Oil
Gas, mcf/mo
Oil, bbl/mo
Water, bbl/mo
GOR-SCF/BBL
100000 1000
10000 100
1000 10
100 1
13
14
15
16
17
18
19
20
21
22
Year
Oil, bbl/mo
Qual= TTC
Ref= 11/2021
Cum= 2697
Rem= 1311
EUR= 4008
Yrs= 36.917
Gas, mcf/mo
Ref= 11/2021
Cum= 0
GOR-SCF/BBL
Water, bbl/m
Ref= 11/2021
Cum= 94303

PROSPECT INACTIVE WELL LIST – FORM 3 Doc. # 403365560 approved 5/23/2023

API Number	Well Name	Well Number	Status	Reason for No Production	Planned Return to Production Date	Planned Plugging Date	Current Status
05-069-05114	MEYER	3	SI	Fresh water source; researching benificial use	5/17/2024		
05-069-05115	WORTH (MUDDY UNIT)	1	TA	Old well		12/6/2023	Form 6 approved on 6/1/2023; Form 6 expired on 11/30/2023 (Doc# 403406405)
05-069-05132	COMMUNITY	3	SI	Intermittent Producer	6/30/2023		
05-069-05136	MARTINEZ, F G	2	SI	Old well		5/17/2024	
05-069-06095	MSSU	30-7	IJ	Shut-in due to nearby residential construction	8/31/2023		
05-069-06255	MSSU	30-10	SI	Waiting on Codell Permit for re-completion	6/28/2025		
05-069-06284	MSSU	30-17	IJ	Shut-in due to nearby residential construction.	8/31/2023		
05-069-06309	MSSU	20-1	SI	Old well		5/17/2024	
05-069-06312	MSSU	17-1	TA	Old well		5/17/2024	
05-069-06313	MSSU	19-10	SI	Waiting on Codell permit for recompletion	6/27/2025		
05-069-06316	MSSU	31-1	SI	Old well		5/17/2024	
05-069-06332	KIIX	1	SI	Waiting on Codell permit for re-completion	6/27/2025		
05-069-06399	MARTINEZ	3	SI	Needs repairs - high flowline pressure	8/31/2023		

https://cogcc.state.co.us/eForms/Public/DownloadFile?file_num=403407412

COLORADO
Oil & Gas Conservation Commission
Department of Natural Resources
1120 Lincoln Street, Suite 801
Denver, CO 80203

April 5, 2022

Mr. Ward Giltner
Prospect Energy LLC, Operator Number 10312
1036 Country Club Estates Dr
Castle Rock, CO 80108

I am writing to request additional information regarding your Form 2, Application for Permit to Drill, to recomplete and operate the MSSU 30-8 well (Document Number: 402704523; Received 10/29/2021; API # 05-069-06253) ("Form 2"). Following a review of your proposed operations, Colorado Oil and Gas Conservation Commission ("COGCC") Staff and I have concluded that your proposal constitutes a significant change to the design and operation of an oil and gas location. Pursuant to COGCC Rules, you must obtain an approved Form 2A and Oil and Gas Development Plan ("OGDP") from the Commission before the Director will consider the Form 2. The only Form 2 for the MSSU 30-8 well was approved on April 25, 1985. No Form 2A has ever been submitted for this location (Location ID# 333083).

For any significant change to the design and operation of an Oil and Gas Location ("Location"), COGCC Rule 304.a.(3) requires operators to submit a completed Form 2A. Since the Location at issue was originally constructed, the area surrounding the Location has changed significantly. The Location is now within 2,000 feet of several residential buildings units, which has increased the potential for adverse impacts to public health, safety, or welfare. The increased potential for adverse impacts and your proposed changes to operations constitute a significant change requiring a new Form 2A.

COGCC Rules also require an approved OGDP or Form 2A for the Location before the Director can approve or deny a Form 2. COGCC Rule 303.a. states that any Location which meets the criteria of Rule 304.a. (i.e., any Location requiring a Form 2A) must have an approved OGDP or Form 2A. Per COGCC Rule 308.a., I cannot approve or deny your Form 2 to recomplete and operate an existing well until you obtain an approved OGDP or Form 2A from the Commission.

Additionally, Rule 308.c. requires that the Director assess and address potential impacts to public health, safety, and welfare as part of the review of a Form 2. COGCC Staff and I cannot adequately assess or address potential impacts without the information provided in an approved Form 2A.

Based on the foregoing, I request that you submit and obtain an approved Form 2A and an OGDP for the Location at issue. Upon providing the Form 2A and the ODGP, COGCC Staff and I will review your Form 2.

If you have any questions, please contact my office.

Sincerely,

Sabrina Trask

Sabrina Trask
Planning & Permitting Manager

COLORADO
Oil & Gas Conservation Commission
Department of Natural Resources
1120 Lincoln Street, Suite 801
Denver, CO 80203

April 5, 2022

Mr. Ward Giltner
Prospect Energy LLC, Operator Number 10312
1036 Country Club Estates Dr
Castle Rock, CO 80108

I am writing to request additional information regarding your Form 2, Application for Permit to Drill, to recomplete and operate the Kiix 1 well (Document Number: 402672241; Received 10/29/2021; API # 05-069-06332) ("Form 2"). Following a review of your proposed operations, Colorado Oil and Gas Conservation Commission ("COGCC") Staff and I have concluded that your proposal involves reworking an existing well located within 500 feet of a lake, pond, or reservoir. COGCC Rule 1202.a.(3) prohibits new staging, refueling, or Chemical storage areas within 500 feet of the Ordinary High Water Mark ("OHWM") of any river, perennial or intermittent stream, lake, pond, or wetland without a signed waiver from Colorado Parks and Wildlife ("CPW") and an approved Form 4, Sundry Notice or Form 2A documenting relief.

Additionally, Rule 308.c. requires that the Director assess and address potential impacts to public health, safety, welfare, the environment, and wildlife resources as part of the review of a Form 2. COGCC Staff and I cannot adequately assess or address potential impacts without the information provided in an approved Form 4 or Form 2A. No Form 2A has ever been submitted for this location (Location ID# 307210).

Based on the foregoing, I request that you obtain and submit an approved Form 2A or Form 4 for the Location at issue. I also request that you obtain a signed waiver from CPW. Upon providing the Form 4 or Form 2A and the signed waiver from CPW, COGCC Staff and I will review your Form 2.

If you have any questions, please contact my office.

Sincerely,

Sabrina Trask

Sabrina Trask
Planning & Permitting Manager

COLORADO
Energy & Carbon Management Commission
Department of Natural Resources
1120 Lincoln Street, Suite 801
Denver, CO 80203

February 8, 2024

Prospect Energy LLC
Attn: Ward Giltner
1036 Country Club Estates Drive
Castle Rock, CO 80108

DIRECTOR'S ORDER PURSUANT TO RULE 901.a.

The Director of the Colorado Energy and Carbon Management Commission ("ECMC" or "Commission") issues this Order pursuant to Rule 901.a. of the Commission's Rules and Regulations, 2 CCR 404-1 ("Rule" or "Rules") and § 34-60-104.5, C.R.S, of the Oil and Gas Conservation Act.

INTRODUCTION AND BACKGROUND

1. Prospect Energy LLC (Operator No. 10312) ("Prospect") is the operator of wells, and related facilities, which are located in Larimer County.

2. Prospect operates the Hearthfire #1 Well, API No. 05-069-06254 ("the Well").

3. On March 31, 2021, Prospect submitted a Form 4, Sundry Notice, (Doc. No. 402143980), requesting to continue Venting or Flaring gas from the Well due to no gas sales line, alleging that the gas production was too low for economic benefit.

4. On September 28, 2022, Prospect submitted a second Form 4, Sundry Notice, (Doc. No. 403179304), requesting to continue Venting or Flaring and included a Gas Capture Plan.

5. On February 16, 2023, ECMC Staff processed the two Forms 4. ECMC Staff attached a Condition of Approval ("COA") to the March 31, 2021, Form 4, stating that "[f]laring after January 15, 2022 requires an approved Gas Capture Plan or an approved Variance." (Doc. No. 402143980). ECMC Staff attached a similar COA to the September 28, 2022, Form 4, stating that "[t]his well should be shut in until a Gas Capture Plan or Variance is approved. Approval was to have been received prior to January 15, 2022." (Doc. No. 403179304).

6. On May 22, 2023, Commission Staff conducted an audit of Prospect's Forms 7, Operator's Monthly reports of Operations, and determined that Prospect continued to Flare gas without an approved Gas Capture Plan or Variance, in violation of the COAs attached to Prospect's Forms 4 (Doc. Nos. 402143980, 403179304) and § 34-60-121(1)(a), C.R.S.

7. On May 31, 2023, Commission Staff issued a Notice of Alleged Violation (Doc. No. 403418205) ("NOAV") directing Prospect to immediately shut in the Well until a revised Gas Capture Plan or Variance could be approved. The corrective action date was June 6, 2023.

8. On October 10, 2023, Prospect submitted an Application for Variance ("Variance") to the ECMC, pursuant to Rule 502.b., requesting a variance to Commission Rule 903 .

9. An audit of Prospect's Form 7s and production reporting shows that Prospect has continued Venting and/or Flaring.

10. The Director has reasonably ascertained the underlying facts on which the Director bases this action. Therefore, the Director has objective grounds and reasonable cause to determine that Prospect, in the conduct of oil and gas operations, is impacting or threatening to impact public health, safety, welfare, the environment, and wildlife resources.

11. Moreover, based on Prospect's actions and inactions described above, the Director has objective grounds and reasonable cause to determine that a suspension of operations is necessary at the Well to ensure that the Commission is following its statutory mandate to protect public health, safety, welfare, the environment, and wildlife resources.

12. Specifically, the Director finds that Prospect has flared and is flaring gas from the Hearthfire #1 Well, violating Rule 903. The Director finds that this situation requires immediate attention, and the Director enters this order requiring Prospect to immediately cease all production operations at the Well.

13. Based on Prospect's actions and inaction described above, the Director has objective grounds and reasonable cause to determine that a suspension of operations is necessary at the Well to ensure that the Commission is following its statutory mandate to protect public health, safety, welfare, the environment, and wildlife resources.

14. The Director will inspect and may take additional action to protect public health, safety, welfare, the environment, and wildlife resources, including shutting-in the Well, until Prospect has come back into compliance with all ECMC Rules.

15. Until ECMC has re-inspected the Well and determined that the ongoing situation has been fully addressed, Prospect will not return the Well to production.

ORDER

In accordance with Rule 901.a., the Director ORDERS that Prospect **immediately cease all venting and flaring at the Hearthfire #1 Well, except under the circumstances detailed in**

Rule 903.d.(1)(A), (B), (D), or (E). Moreover, Prospect will immediately cease all production activities at the Hearthfire #1 Well.

This Order will remain in effect until such time as Prospect has come back into compliance with all ECMC Rules; including, but not limited to, those instances of non-compliance described above.

Prospect's well or facility will not be returned to production until the ECMC has re-inspected and determined that the ongoing threat to public safety has been fully addressed.

Prospect should direct all questions regarding this Order, and the steps Prospect must take to return to compliance with ECMC Rules, as required by this Order, to Mike Leonard, Compliance Manager and Diana Burn, Engineering Manager.

The provisions contained in the above Order are effective immediately. If Prospect does not comply with the Order, the Director may take action to assess, shut-in, plug and abandon and/or remediate Prospect's wells and seek costs pursuant to § 34-60-124, C.R.S.

The Director expressly reserves the right to alter, amend, or repeal any and/or all of the above orders.

EXECUTED February 8, 2024.

IN THE NAME OF THE STATE OF COLORADO

ENERGY & CARBON MANAGEMENT COMMISSION

Julie Murphy
ECMC Director

COLORADO

Department of Public Health & Environment

AIR POLLUTION CONTROL DIVISION

COMPLIANCE ADVISORY

CASE NO. 2019-167
2019-168
AIRS NO. 069-0173
069-0180
INSPECTION DATE: March 27, 2019

U.S. CERTIFIED MAIL NO. 7016 2710 0000 3004 2739
MAILING DATE: October 2, 2019
SOURCE CONTACT: Ward Giltner

IN THE MATTER OF PROSPECT ENERGY, LLC

This Compliance Advisory provides formal notice, pursuant to § 25-7-115(2), C.R.S., of alleged violations or noncompliance discovered during the Air Pollution Control Division's ("Division") inspection and/or review of records related to Prospect Energy, LLC's Facilities identified below. The Division is commencing this action because it has cause to believe that the compliance issues identified below may constitute violations of the Colorado Air Pollution Prevention and Control Act ("the Act") and its implementing regulations.

Please be aware that you are responsible for complying with applicable State air pollution requirements and that there are substantial penalties for failing to do so. Pursuant to the enforcement authority provided the Division by § 25-7-115, C.R.S., any person who violates the Act, its implementing regulations or any permit issued thereunder may be issued an order for compliance that can include permit revocation and assessment of penalties of up to $15,000 per day of such violation in accordance with § 25-7-122, C.R.S. The issuance of this Compliance Advisory does not in any way limit or preclude the Division from pursuing additional enforcement options concerning this inspection/review. Also, this Compliance Advisory does not constitute a bar to enforcement action for violations not specifically addressed in this Compliance Advisory.

Failure to respond to this Compliance Advisory by the date indicated at the end of this Compliance Advisory may be considered by the Division in the subsequent enforcement action and the assessment of penalties. Furthermore, the Division's enforcement process contemplates a full and final resolution of the compliance issues herein addressed, and those that may result from further review, in a timely manner. If at any time throughout the process of reaching such a resolution the Division determines that the Parties cannot agree to the dispositive facts, compliance requirements and/or penalty assessments (if any) associated with this Compliance Advisory, or a resultant enforcement action, the Division may exercise its full enforcement authority allowed under the law.

Prospect Energy, LLC ("Prospect") owns and operates the following oil and gas extraction facilities (collectively, "Facilities"):

- AIRS Number 069-0173, Krause well production facility, located 4.2 mi. NE of Hwy. 14 & US Hwy. 287, Fort Collins, Larimer County, Colorado ("Krause Facility"). The Krause Facility is subject to the terms and conditions of Air Quality Control Statutes and Colorado Air Quality Control Commission ("AQCC") Regulations.

- AIRS Number 069-0180, Fort Collins-Meyer well production facility, located at NWNW Section 30, Township 8N, Range 68W, Fort Collins, Larimer County, Colorado ("Fort Collins-Meyer Facility"). The Fort Collins-Meyer Facility is subject to the terms and conditions of Air Quality Control Statutes and Colorado Air Quality Control Commission ("AQCC") Regulations.

I. ALLEGED VIOLATIONS AND FACTS

On March 27, 2019, Tim Taylor, of the Division, conducted Partial Compliance Evaluations ("Inspections") of the Facilities. Based on the inspections, and a review of records related to the Facilities, the Division has identified the following compliance issues:

Krause Facility

A. Pursuant to AQCC Regulation Number 3, Part A, § II.A. and § 25-7-114.1, C.R.S., no person shall allow emission of air pollutants from, or construction, modification or alteration of, any facility, process, or activity which constitutes a stationary source, from which air pollutants are, or are to be, emitted unless and until an Air Pollutant Emission Notice ("APEN") and the associated APEN fee has been filed with the Division with respect to such emission. Prospect began routing separator gas to the enclosed combustion device at the Krause

Facility in February, 2017, but Prospect failed to submit an APEN for gas venting from the separator until June 12, 2019, violating AQCC Regulation Number 3, Part A, § II.A. and § 25-7-114.1, C.R.S. Controlled volatile organic compound (“VOC”) emissions from gas venting were 10.9 tpy during 2018 and 11.9 tpy during 2017.

B. Pursuant to AQCC Regulation Number 3, Part B, § II.A.1. and § 25-7-114.2, C.R.S., no person shall commence construction of any stationary source or modification of a stationary source without first obtaining or having a valid construction permit from the Division. Prospect began venting gas at the Krause Facility in February, 2017, but Prospect has failed to obtain a valid construction permit for the emission source to date, violating AQCC Regulation Number 3, Part B, § II.A.1. and § 25-7-114.2, C.R.S. Controlled volatile organic compound (“VOC”) emissions from gas venting were 10.9 tpy during 2018 and 11.9 tpy during 2017.

Fort Collins-Meyer Facility

C. Pursuant to AQCC Regulation Number 3, Part A, § II.A. and § 25-7-114.1, C.R.S., no person shall allow emission of air pollutants from, or construction, modification or alteration of, any facility, process, or activity which constitutes a stationary source, from which air pollutants are, or are to be, emitted unless and until an APEN and the associated APEN fee has been filed with the Division with respect to such emission. Prospect began routing separator gas to the enclosed combustion devices at the Fort Collins-Meyer Facility in February, 2017, but Prospect failed to submit an APEN for gas venting from the separator until June 12, 2019, violating AQCC Regulation Number 3, Part A, § II.A. and § 25-7-114.1, C.R.S. Controlled volatile organic compound (“VOC”) emissions from gas venting were 1.9 tpy during 2018 and 2.1 tpy during 2017.

D. Pursuant to AQCC Regulation Number 3, Part B, § II.A.1. and § 25-7-114.2, C.R.S., no person shall commence construction of any stationary source or modification of a stationary source without first obtaining or having a valid construction permit from the Division. Prospect began venting gas at the Fort Collins-Meyer Facility in February, 2017, but Prospect has failed to obtain a valid construction permit for the emission source to date, violating AQCC Regulation Number 3, Part B, § II.A.1. and § 25-7-114.2, C.R.S. Controlled volatile organic compound (“VOC”) emissions from gas venting were 1.9 tpy during 2018 and 2.1 tpy during 2017.

It is important to resolve the above-referenced issues as soon as possible. Therefore, the Division encourages Prospect to immediately identify those compliance issues that are not in dispute and to rectify those issues before the upcoming Compliance Advisory meeting. In accordance with § 25-7-115(3)(a), C.R.S., the Compliance Advisory meeting will be held within thirty (30) days of the Division's issuance of the Compliance Advisory in this matter. The Division also requests that Prospect provide the Division with a brief written response to the alleged violations ("Source Response"). The Source Response should identify the undisputed compliance issues and, if an alleged violation is disputed, the basis for the dispute. The Division requests that Prospect provide the Source Response, to the attention of Jeremy Schuster, no later than ten business days before the Compliance Advisory meeting. At the upcoming meeting, the Division will confirm the actions taken to rectify the undisputed compliance issues and proceed with unresolved matters as outlined below.

If you have any questions regarding this Compliance Advisory, the Division's enforcement processes, or any related issues, please refer to the APCD Enforcement Guide located at https://www.colorado.gov/pacific/cdphe/inspections-and-enforcement and/or contact the Division personnel identified below.

II. COMPLIANCE ADVISORY MEETING

Prospect is requested to contact the Division and schedule a meeting to:

- Discuss the disputed Compliance Advisory issues and answer any remaining questions you may have;
- Submit information necessary to successfully show that the deficiencies and noncompliance issues (or any portion of them) are not violations of Colorado's air pollution laws; and
- Establish a mutually acceptable schedule and guidelines for the full and final resolution of any remaining deficiencies and noncompliance issues in a timely manner.

Please contact the Enforcement Advisor identified below by no later than October 10, 2019 to schedule a meeting with the Division to discuss the Compliance Advisory. The Division currently anticipates that the meeting will take place during the week of October 28, 2019.

Jeremy Schuster, Enforcement Advisor (303-692-3131)

To ensure meaningful communication with all Coloradans, the Division offers free language services. Please let us know if we can provide an interpreter for anyone attending the Compliance Advisory meeting.

cc: Shannon McMillan, APCD
Jennie Morse, APCD
Heather Wuollet, APCD
Chris Laplante, APCD
Michael Stovern, EPA (Region VIII)
Tim Taylor, APCD
Jen Mattox, APCD
Tom Lovell, APCD
Tom Roan, Attorney General's Office
File

COLORADO
Department of Public Health & Environment

Issued on: 11/10/20

Ward Giltner
Prospect Energy LLC
1036 Country Club Estates Drive
Castle Rock, CO 80108

RE: Warning Letter to Prospect Energy LLC. Regarding non-compliance at Krause Facility
AIRS No: 069-0173

Dear Ward,

This Warning Letter provides notice to Prospect Energy LLC related to compliance issues discovered by the Air Pollution Control Division (Division). The Company owns and operates Krause well production facility at Site Location: 4.2 mi. NE of Hwy. 14 & Hwy. 287. The Facility is subject to the terms and conditions of the GP08 permit issued to the Company on 02/11/16, Colorado Air Quality Control Statutes, and Colorado Air Quality Control Commission (AQCC) Regulations.

On 10/08/19, Jenna Channel of the Division inspected the Facility. Based on the inspection and a review of records related to the facility, the Division is issuing this Warning Letter for the following non-compliance issue(s):

A. Pursuant to Permit GP08, Condition IV.A.6 and IV.B owners and operators of storage tanks covered by this permit shall route all VOC emissions to air pollution control equipment and shall operate without venting VOC emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operations unless venting is reasonably required for maintenance, gauging or safety of personnel or equipment. During a full compliance evaluation (FCE) of the Krause facility on October 8, 2019 while utilizing an Optical Gas Imaging Infrared Camera (IR Camera) for inspection of the condensate tanks, emissions were observed venting from the two (2) most southern tanks of the battery. Emissions from each tank appeared to be venting from the thief hatch. Other venting occurrences were detected by both Prospect and the Division during the compliance period; on 11/7/18 and 6/25/19 in which emissions were detected venting from tank thief hatches during normal operations and not while maintenance was being conducted (see Regulation No. 7 Box Section XII.D or XVII.C.1. (XVII.C2.a). Prospect failed to operate without venting VOC emissions violating Permit GP08, Condition IV.A.6.

B. Pursuant to Regulation No. 7, XII.C.1.b, All condensate collection, storage, processing and handling operations, regardless of size, shall be designed, operated and maintained so as to minimize leakage of volatile organic compounds to the atmosphere to the maximum extent practicable. During a FCE of the Krause facility on October 8, 2019 while utilizing an Optical Gas Imaging Infrared Camera (IR Camera) for inspection of the condensate tanks, emissions were observed venting from the two (2) most southern tanks of the battery. Emissions from each tank appeared to be venting from the thief hatch. Other venting occurrences were detected by both Prospect and the Division during the compliance period; on 11/7/18 and 6/25/19 in which emissions were detected venting from tank thief hatches during normal operations and not while maintenance was being conducted (see Regulation No. 7 Box Section XII.D or XVII.C.1. (XVII.C2.a.). Prospect failed to operate and maintain condensate and crude oil storage so as to minimize leakage of volatile organic compounds to the atmosphere to the maximum extent practicable violating Regulation No. 7, XII.C.1.b.

D. Pursuant to Regulation No. 7, §XVII.C.2.a, the operator shall demonstrate that emissions are not venting as prohibited. The Division expects this demonstration to be made through the provision of information identifying the cause of the emissions as well as the operator’s strategies, procedures, and practices (Regulation No. 7, §XVII.C.2.b) employed to ensure compliance. The Division received insufficient information from the operator to enable the Division to conclude that the observed emissions were not venting. Without this demonstration by the operator, and based on the information the Division does have, the Division determined the operator failed to operate without venting on 11/7/18, 6/25/19, and 10/8/19 violating Regulation No. 7, §XVII.C.2.a.

E. Pursuant to Regulation 7, XVII.H, regarding Well Unloading/Maintenance, beginning May 1, 2014, owners or operators must use best management practices to minimize hydrocarbon emissions and the need for well venting associated with downhole well maintenance and liquids unloading, unless venting is necessary for safety. Prospect did not provide evidence or records that could determine compliance regarding well-unloading and maintenance, violating Regulation No. 7 XVII.H.

The Company addressed the violations by completing a design analysis on July 6, 2020, and implementing design changes at the facility. In addition, the Company formally committed to follow the Vapor Control System (VCS) Guidelines in September 2020, and will conduct the required inspections, monitoring, repairs, record-keeping, and reporting as part of their Operating and Maintenance (O&M) Plan and submit records to the Division as requested.

This letter constitutes a formal warning that the Company operated in violation of Permit GP08, and Regulation No. 7, §§XII.C.1.b, XVII.C.2.a, and XVII.H. Please be aware that you are responsible for complying with State air pollution regulations and that there are substantial administrative and civil penalties for failing to do so. Pursuant to the enforcement authority provided the Division by § 25-7-115, C.R.S., any person who violates the Act, its implementing regulations or any permit issued thereunder may be issued an order for compliance that can include permit revocation and assessment of penalties in accordance with § 25-7-122, C.R.S.

If you have any questions concerning this matter, contact me at 303-692-3195 or Ms. Jen Mattox at 303-692-3144.

Sincerely,

Jenna Channel

Jenna Channel
Environmental Protection Specialist

cc: Jennifer Mattox, APCD
Jennifer Morse, APCD
Christopher Laplante, APCD
Heather Wuollet, APCD
Shannon McMillan, APCD
File

COLORADO
Air Pollution Control Division
Department of Public Health & Environment

Air Pollution Control Division
Field Inspection Report

County Code: 069		Source Code: 0173	
Date of Inspection: 11/15/2021		Date Report Submitted: 12/06/2021	
Inspector: Craig Giesecke			
Company Name: Prospect Energy, LLC		Facility Name: Krause Battery	
Site Location: 4.2 mi. NE of Hwy. 14 & Hwy. 287		County: Larimer	
Contact Person: Ward Giltner		Phone Number: 303-489-8773	
Permit Number: GP05		Time: 10:00 a.m.	
Company Mailing Address: 1036 Country Club Estates Drive, Castle Rock, CO 80108			
Source Class: Synthetic Minor			
Inspection Type: PCE			
Travel and Prep: 2.0	Hours Inspection: 1.0	Hours Report: 7.0	Total Hours: 10.0
Applicable Subparts (NSPS/MACT): N/A			
Compliance Status: NOT in compliance			

Compliance History:
No previous INOVs for this facility.

Description of Source and Inspection Summary
On November 15, 2021, Craig Giesecke, of the Air Pollution Control Division ("Division"), conducted a partial compliance evaluation ("PCE") inspection of the Krause Battery ("Facility"), owned and operated by Prospect Energy, LLC ("Company"). The PCE was conducted as part of an investigation stemming from a complaint received by the Division on November 12, 2021. The Facility is an unmanned well production facility, and consists of the following emissions points:

AIRS Point	Permit Number	Point Description
002	GP08	Four (4) 300 bbl crude oil storage tanks, controlled by an enclosed combustor.
003	11LR1428.XP	Crude oil loading operations, uncontrolled.
004	19LR0685	Venting of gas from a 3-phase separator to an enclosed combustor.
005	GP05	Three (3) produced water storage tanks, controlled by an enclosed combustor. Tanks identified as **West** (300 bbl), and **Center** and **East** (400 bbl each).

At the time of the inspection Mr. Giesecke was not accompanied by any company personnel. Upon arrival to the Facility, Mr. Giesecke observed with the IR camera emissions coming from two (2) of the three (3) produced water storage tanks. Upon closer observation, he determined that there were emissions from each thief hatch on the Center and East produced water tanks. He also observed emissions from a patched area on the roof of the Center produced water tank. He then completed an inspection of the entire Facility with the IR Camera to look for any additional issues. A rotten egg smell was noted near an equipment shed at the base of the water tanks, though no emissions were observed with the IR camera from the shed's open door nor from any equipment visible inside. No odor was detected from beyond the Facility fence line. Emissions observed with the IR camera appeared to be intermittent and fluctuated over the duration of Mr. Giesecke's inspection. Mr. Giesecke recorded a video of produced water storage tank emissions using the IR Camera. Mr. Giesecke entered the inspection details in the Division's IR Camera System and notified the Company of the issues on November 16, 2021.

In a phone conversation on November 23, 2021, the Company's environmental consultant indicated to Mr. Giesecke that from March 2, 2021 to September 16, 2021, the Company had completed approximately five (5) repair attempts on the Center tank using fiberglass patching, and that the patches were repeatedly ineffective at reliably preventing emissions from what were determined to be crack(s) or hole(s) in the Center tank. Prior to the Division's November 15, 2021 inspection, the Center tank was most recently patched September 16, 2021. The Company completed another patch repair on November 24, 2021. The Company has purchased two (2) new fiberglass storage tanks to replace the Center and East tanks, and anticipates having them in operation by mid-December. The Company indicated that it is infeasible to shut in the site or isolate the Center tank as that would result in the potential for water lines to freeze and that shutting in would not stop the emissions since the tank would still contain liquids.

The Facility is located in the 8-hour ozone nonattainment area and is subject to Regulation No. 7, Part D § I.C. Furthermore, uncontrolled actual emissions from the produced water storage tanks are greater than 2 tpy VOC (as identified in the most recent APEN, received May 27, 2021) and therefore are subject to Regulation No. 7, Part D § II.C.1. Pursuant to Regulation No. 7, Part D § II.C.2.a.(i)(B), venting is emissions from a controlled storage tank thief hatch, pressure relief device, or other access point to the storage tank, which are the result of an open, unlatched, or visibly unseated pressure relief device (e.g., thief hatch or pressure relief valve), an open vent line, or an unintended opening in the storage tank (e.g., crack or hole). Though emissions were observed from both thief hatches and an unintended opening, this PCE is intended to specifically address the cracked tank while further information is gathered to evaluate emissions from the thief hatches. Additional evaluation of the thief hatch emissions will follow through another inspection report.

Based on the physical inspection of the Facility, the Company is NOT in compliance with the following requirements of AQCC Regulation No. 7, Part D §§ I and II:

A. Pursuant to AQCC Regulation No. 7, Part D § I.C.1.b, all hydrocarbon liquids and produced water collection, storage, processing, and handling operations, regardless of size, must be designed, operated, and maintained so as to minimize emission of volatile organic compounds to the atmosphere to the maximum extent practicable. As described above, the Company failed to minimize leakage of volatile organic compounds to the atmosphere to the maximum extent practicable, violating AQCC Regulation No. 7, Part D § I.C.1.b.

B. Pursuant to AQCC Regulation No. 7, Part D § II.C.2.a, owners or operators of storage tanks must route all hydrocarbon emissions to air pollution control equipment, and must operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation, unless venting is reasonably required for maintenance, gauging (unless the use of a storage tank measurement system is required pursuant to and the operator compiles with Section II.C.4.), or safety of personnel and equipment. As described above, the Company failed to operate without venting hydrocarbon emissions, violating AQCC Regulation No. 7, Part D § II.C.2.a.

Mr. Giesecke recommends the issuance of an Immediate Notice of Violation to resolve the violations found as a result of the inspection.

COLORADO
Air Pollution Control Division
Department of Public Health & Environment

AIR POLLUTION CONTROL DIVISION

IMMEDIATE NOTICE OF VIOLATION CASE NO. 2021-119

MAILING DATE: 12/06/21

IN THE MATTER OF Prospect Energy, LLC

The Colorado Department of Public Health and Environment ("CDPHE"), through the Air Pollution Control Division ("Division"), issues this Immediate Notice of Violation to Prospect Energy, LLC (the "Company") pursuant to the Division's authority under §25-7-115(2), C.R.S.

I. ALLEGED FINDINGS OF FACT AND VIOLATIONS

1. The Division issues this Immediate Notice of Violation following a partial compliance evaluation ("PCE") of the Company's facility located at 4.2 mi. NE of Hwy. 14 & Hwy. 287 (the "Facility") in Larimer County. The Facility is subject to statutes and regulations including, but not limited to, the Colorado Air Quality Control Statutes and Colorado Air Quality Control Commission ("AQCC") Regulations.

2. The Division conducted a PCE of the Facility on November 15, 2021. The inspection was performed by Craig Giesecke, Field Enforcement Officer with the Division's Oil and Gas Program.

3. Based upon that PCE, and a review of certain records related to the Facility, the Division has identified the following alleged violation(s):

A. Pursuant to AQCC Regulation No. 7, Part D § I.C.1.b, all hydrocarbon liquids and produced water collection, storage, processing, and handling operations, regardless of size, must be designed, operated, and maintained so as to minimize emission of volatile organic compounds to the atmosphere to the maximum extent practicable. On November 15, 2021, Craig Giesecke observed emissions from a crack or hole in the roof of the center produced water storage tank, which has been ineffectively repaired since at least March 2, 2021. The Company failed to minimize leakage of volatile organic compounds to the atmosphere to the maximum extent practicable, violating AQCC Regulation No. 7, Part D § I.C.1.b.
B. Pursuant to AQCC Regulation No. 7, Part D § II.C.2.a, owners or operators of storage tanks must route all hydrocarbon emissions to air pollution control equipment, and must operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation, unless venting is reasonably required for maintenance, gauging (unless the use of a storage tank measurement system is required pursuant to and the operator compiles with Section II.C.4.), or safety of personnel and equipment. On November 15, 2021, Craig Giesecke observed emissions from a crack or hole in the roof of the center produced water storage tank, which has been ineffectively repaired since at least March 2, 2021. The Company failed to operate without venting hydrocarbon emissions, violating AQCC Regulation No. 7, Part D § II.C.2.a.

II. PENALTY PROVISIONS

4. Pursuant to the enforcement authority provided the Division by § 25-7-115, C.R.S., any person who violates the Act, its implementing regulations or any permit issued thereunder may be issued an order for compliance that can include permit revocation and assessment of penalties in accordance with § 25-7-122, C.R.S.

5. Section 25-7-115(5), C.R.S., requires the Division to determine if a noncompliance penalty is applicable. If applicable, the Division may assess the penalty for any period of violation from the date that non-compliance began until the date on which compliance is achieved.

III. CONFERENCE REGARDING THE ALLEGED VIOLATIONS

6. In accordance with § 25-7-115(3), C.R.S., the Company is entitled to meet with the Division within thirty days of the effective date of this Immediate Notice of Violation in order for the Division to assess the alleged noncompliance and evaluate whether a noncompliance penalty must be assessed. The purpose of this conference is to permit the Company an opportunity to submit data, views, and arguments

concerning the alleged violation or noncompliance or the assessment of any noncompliance penalty. The Division strongly encourages the Company to submit its data, views, and arguments in writing within the thirty day time period in lieu of an in-person conference. However, should the Company wish to conduct the conference in-person, the Division is available to meet. Should the Company wish to attend an in-person conference, please contact Shannon McMillan, phone number 303-692-3259, to schedule the meeting. The Company is encouraged to submit a written response to this Immediate Notice of Violation prior to any scheduled conference. Upon completion of the investigation, the Division will determine how to close out this case and may assess civil and/or noncompliance penalties, as appropriate.

7. If the Company fails to contact the Division within thirty days of the effective date of this Immediate Notice of Violation, the Division may issue a Compliance Order and may assess penalties against the Company. Subsequent violation of the Compliance Order may subject the Company to further enforcement action under §§ 25-7-121 and -122, C.R.S.

IV. DATE OF NOTICE

8. This Immediate Notice of Violation serves as notice under § 25-7-115(2), C.R.S., and is considered effective upon December 6, 2021.

Electronic cc:

Shannon McMillan, APCD
Chris Laplante, APCD
Jennifer Mattox, APCD
Jennifer Morse, APCD
Heather Wuollet, APCD
Tom Lovell, APCD
Tom Roan, Office of Attorney General
Michael Stovern, US EPA

COLORADO
Department of Public Health & Environment

AIR POLLUTION CONTROL DIVISION

COMPLIANCE ADVISORY

CASE NO. 2022-020
AIRS NO. 069-0173
INSPECTION DATES: November 15, 2021
January 28, 2022

SENT VIA ELECTRONIC MAIL
MAILING DATE: March 2, 2022
SOURCE CONTACT: Ward Giltner

IN THE MATTER OF PROSPECT ENERGY, LLC

This Compliance Advisory provides formal notice, pursuant to § 25-7-115(2), C.R.S., of alleged violations or noncompliance discovered during the Air Pollution Control Division's ("Division") inspection and/or review of records related to Prospect Energy, LLC's Facility identified below. The Division is commencing this action because it has cause to believe that the compliance issues identified below may constitute violations of the Colorado Air Pollution Prevention and Control Act ("the Act") and its implementing regulations.

Please be aware that you are responsible for complying with applicable State air pollution requirements and that there are substantial penalties for failing to do so. Pursuant to the enforcement authority provided the Division by § 25-7-115, C.R.S., any person who violates the Act, its implementing regulations or any permit issued thereunder may be issued an order for compliance that can include permit revocation and assessment of penalties in accordance with § 25-7-122, C.R.S. The issuance of this Compliance Advisory does not in any way limit or preclude the Division from pursuing additional enforcement options concerning this inspection/review. Also, this Compliance Advisory does not constitute a bar to enforcement action for violations not specifically addressed in this Compliance Advisory.

Failure to respond to this Compliance Advisory by the date indicated at the end of this Compliance Advisory may be considered by the Division in the subsequent enforcement action and the assessment of penalties. Furthermore, the Division's enforcement process contemplates a full and final resolution of the compliance issues herein addressed, and those that may result from further review, in a timely manner. If at any time throughout the process of reaching such a resolution the Division determines that the Parties cannot agree to the dispositive facts, compliance requirements and/or penalty assessments (if any) associated with this Compliance Advisory, or a resultant enforcement action, the Division may exercise its full enforcement authority allowed under the law.

Prospect Energy, LLC ("Prospect") owns and operates the Krause Tank Battery, a well production facility located 4.2 miles northeast of Highway 14 and US Highway 287, Larimer County, Colorado ("Facility"). The Facility is subject to the terms and conditions of Colorado Construction Permit Number 19LR0685, Issuance 1 issued to Prospect on October 28, 2019, Final Approval issued September 3, 2020 ("Permit Number 19LR0685"); Colorado General Construction Permit Number GP05, Version 3, Final Approval issued January 24, 2020 ("GP05"); Colorado Air Quality Control Statutes; and Colorado Air Quality Control Commission ("AQCC") Regulations. The following emissions points located at the Facility are relevant to this enforcement action:

AIRS Point	Point Description	Permit Number
002	Four (4) 300 bbl atmospheric crude oil storage tanks, controlled by an enclosed combustor.	GP08
003	Crude oil loadout operations, controlled by an enclosed combustor.	11LR1428.XP
004	Separator gas venting, controlled by an enclosed combustor.	19LR0685
005	Two (2) 400 bbl and one (1) 300 bbl produced water storage tanks, controlled by an enclosed combustor.	GP05

I. ALLEGED VIOLATIONS AND FACTS

On November 15, 2021, January 28, 2022, and February 8, 2022, Craig Giesecke, of the Division, inspected the Facility. On January 28, 2022, Sydney McLeod, of the Larimer County Department of Health and Environment, a duly delegated representative of the Division, conducted an odor observation at the Facility. Based on the inspections, and a review of records related to the Facility, the Division has identified the following compliance issues:

A. Pursuant to AQCC Regulation Number 3, Part A, § II.A.1, no person shall allow emission of air pollutants from, or construction, modification or alteration of, any facility, process, or activity which constitutes a stationary source, except residential structures, from which air pollutants are, or are to be, emitted unless and until an Air Pollutant Emission Notice ("APEN") and the associated APEN fee has been filed with the Division with respect to such emission. Prospect failed to file an APEN for the produced water tanks at the Facility (now AIRS Point 005) until May 27, 2021, in violation of AQCC Regulation 3, Part A, § II.A.[1]

B. Pursuant to AQCC Regulation Number 3, Part A, § II.C.1.e, a revised APEN shall be filed with the Division before the current APEN expires. Pursuant to AQCC Regulation Number 3, Part A, § II.C.3.a, a revised APEN shall be submitted no later than thirty days before the five-year term expires. Prospect submitted an APEN for AIRS Point 002 on January 4, 2016, and a revised APEN was due no later than December 5, 2020. Prospect failed to submit a revised APEN for AIRS Point 002 until May 27, 2021, in violation of AQCC Regulation Number 3, Part A, §§ II.C.1.e and II.C.3.a.

C. Pursuant to AQCC Regulation Number 3, Part B, § II.A.1, no person shall construct, modify, or operate any stationary source or commence the conduct of any such activity without first obtaining or having a valid construction permit from the Division. Prospect failed to obtain a permit for the produced water tanks at the Facility (now AIRS Point 005) until May 27, 2021, in violation of AQCC Regulation 3, Part B, § II.A.1.[1]

D. Pursuant to AQCC Regulation Number 7, Part D, § I.C.1.b, all hydrocarbon liquids and produced water collection, storage, processing and handling operations, regardless of size, must be designed, operated and maintained so as to minimize leakage of volatile organic compounds to the atmosphere to the maximum extent practicable. The following emissions were observed at the Facility:

[1] The produced water tanks were previously APEN and permit exempt. Prospect reported uncontrolled actual VOC emissions of 44.7 tons per year in the APEN submitted on May 27, 2021, based on 2020 emissions data.

Date emissions observed	Location of emissions	Repair date
1/28/2021	East PW TH	1/29/2021
3/2/2021	Oil #1 TH	3/4/2021
3/2/2021	Oil #2 TH	3/4/2021
3/2/2021	Oil #3 TH	3/4/2021
3/2/2021	Oil #4 TH	3/4/2021
3/2/2021	East PW TH	3/2/2021
3/2/2021	East PW roof (holes)	3/5/2021
3/2/2021	Center PW TH	3/2/2021
3/2/2021	Center PW roof (holes)	3/5/2021
3/31/2021	Oil #1 TH	4/1/2021
6/7/2021	East PW TH	1/12/2022
6/7/2021	East PW roof (holes)	1/12/2022
6/7/2021	Center PW TH	1/31/2022
6/7/2021	Center PW roof (holes)	1/31/2022
6/7/2021	Oil #3 TH	6/9/2021
6/7/2021	Oil #4 TH	6/9/2021
9/13/2021	East PW roof (holes)	1/12/2022
9/13/2021	Center PW roof (holes)	1/31/2022
11/15/2021	East PW TH	1/12/2022
11/15/2021	Center PW TH[2]	1/31/2022
1/28/2022	Oil #3 TH	2/9/2022

As indicated above, Prospect failed to operate and maintain hydrocarbon liquid and produced water storage operations so as to minimize leakage of volatile organic compounds to the atmosphere to the maximum extent practicable, violating AQCC Regulation Number 7, Part D, § I.C.1.b.

E. Pursuant to AQCC Regulation Number 7, Part D, § XVII.C.2.a (2019) and AQCC Regulation Number 7, Part D, § II.C.2.a (2020), for storage tanks, Prospect must route all hydrocarbon emissions to air pollution control equipment, and must operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or

[2] On December 6, 2021, the Division issued an Immediate Notice of Violation (INOV) to Prospect regarding this emission observation.

pressure relief device during normal operation, unless venting is reasonably required for maintenance, gauging, or safety of personnel and equipment. Pursuant to AQCC Regulation Number 7, Part D, § II.C.2.a.(iii) (2020), when venting is observed, Cub Creek must confirm within twenty-four (24) hours of taking action to return the storage tank to operation without venting that the action(s) taken was effective. The following emissions were observed at the Facility:

Date emissions observed	Location of emissions	Repair date
12/18/2019	Center PW TH	12/18/2019
1/28/2021	East PW TH	1/29/2021
3/2/2021	Oil #1 TH	3/4/2021
3/2/2021	Oil #2 TH	3/4/2021
3/2/2021	Oil #3 TH	3/4/2021
3/2/2021	Oil #4 TH	3/4/2021
3/2/2021	East PW TH	3/2/2021
3/2/2021	East PW roof (holes)	3/5/2021
3/2/2021	Center PW TH	3/2/2021
3/2/2021	Center PW roof (holes)	3/5/2021
3/31/2021	Oil #1 TH	4/1/2021
6/7/2021	East PW TH	1/12/2022
6/7/2021	East PW roof (holes)	1/12/2022
6/7/2021	Center PW TH	1/31/2022
6/7/2021	Center PW roof (holes)	1/31/2022
6/7/2021	Oil #3 TH	6/9/2021
6/7/2021	Oil #4 TH	6/9/2021
9/13/2021	East PW roof (holes)	1/12/2022
9/13/2021	Center PW roof (holes)	1/31/2022
11/15/2021	East PW TH	1/12/2022
11/15/2021	Center PW TH**Error! Bookmark not defined.**	1/31/2022
1/28/2022	Oil #3 TH	2/9/2022

As indicated above, Prospect failed to route all hydrocarbon emissions to air pollution control equipment and operate without venting hydrocarbon emissions from storage tank thief hatches and pressure relief devices. Additionally, for the emissions identified on June 7, 2021; September 13, 2021; and November 15, 2021, Prospect has failed to confirm that any action to return the applicable tanks to operation without venting was effective. Therefore, Prospect is in violation of AQCC Regulation Number 7, Part D, § XVII.C.2.a (2019); AQCC Regulation Number 7, Part D, § II.C.2.a (2020); and AQCC Regulation Number 7, Part D, § II.C.2.a.(iii) (2020).

F. Pursuant to AQCC Regulation Number 7, Part D, § II.E.4.d, beginning calendar year 2020, Prospect must inspect components for leaks using an approved instrument monitoring method (AIMM) in accordance with the inspection frequency in Table 3. Based on reported uncontrolled actual VOC emissions, Prospect was required to complete AIMM inspections on a quarterly basis from January 2020 through April 2021, and on a monthly basis beginning in May 2021[3]. Prospect failed to conduct AIMM inspections in the following periods:

Required AIMM frequency	Periods missed
Quarterly	January-March 2020
	April-June 2020
	July-September 2020
	October-December 2020
Monthly	May 2021
	July 2021
	August 2021
	October 2021

Prospect failed to complete required AIMM inspections, as shown in the table above, violating AQCC Regulation Number 7, Part D, § II.E.4.d

G. Pursuant to AQCC Regulation Number 2, Part A, § I.B, Prospect shall not cause or allow the emission of odorous air contaminants from any single source such as to result in odors that are detectable after the odorous air has been diluted with fifteen (15) or more volumes of odor free air ("15:1 d/t"). On January 28, 2022, Larimer County observed odors in excess of the 15:1 d/t limit, as detailed below.

[3] The Facility is located within 1,000 feet of an occupied area. Prior to May 2021, Prospect reported less than 12 tons per year of VOC emissions from the highest emitting storage tank at the Facility. In May 2021, Prospect submitted an APEN for AIRS Point 005, which included estimated annual uncontrolled actual VOC emissions above 12 tons per year; making the Facility then subject to monthly AIMM inspections.

Time	Odor reading	Location
12:30 PM	No odor detected	Upwind
1:10 PM	No odor detected	Upwind
1:30 PM	32:1	Downwind
1:31 PM	32:1	Downwind
1:50 PM	32:1	Downwind
2:00 PM	32:1	Downwind
2:08 PM	No odor detected	Upwind

On January 28, 2022, Prospect failed to ensure that emission of odorous air contaminants remained below the 15:1 d/t limit, violating AQCC Regulation Number 2, Part A, § I.B.

H. Pursuant to Permit Number 19LR0685, Condition 11 and GP05, Condition II.B.2, the permit number and ten digit AIRS ID number assigned by the Division shall be marked on AIRS Points 004 and 005 for ease of identification. Prospect has failed to mark the applicable permit numbers and AIRS IDs on AIRS Points 004 and 005, violating Permit Number 19LR0685, Condition 11 and GP05, Condition II.B.2.

It is important to resolve the above-referenced issues as soon as possible. Therefore, the Division encourages Prospect to immediately identify those compliance issues that are not in dispute and to rectify those issues before the upcoming Compliance Advisory meeting. The Division also requests that Prospect provide the Division with a brief written response to the alleged violations ("Source Response"). The Source Response should identify the undisputed compliance issues and, if an alleged violation is disputed, the basis for the dispute. The Division requests that Prospect provide the Source Response, to the attention of Jeremy Schuster, no later than ten business days before the Compliance Advisory meeting. At the upcoming meeting, the Division will confirm the actions taken to rectify the undisputed compliance issues and proceed with unresolved matters as outlined below.

If you have any questions regarding this Compliance Advisory, the Division's enforcement processes, or any related issues, please refer to the APCD Enforcement Guide located at https://www.colorado.gov/pacific/cdphe/inspections-and-enforcement and/or contact the Division personnel identified below.

II. COMPLIANCE ADVISORY MEETING

Prospect is requested to contact the Division and schedule a meeting to:

- Discuss the disputed Compliance Advisory issues and answer any remaining questions you may have;
- Submit information necessary to successfully show that the deficiencies and noncompliance issues (or any portion of them) are not violations of Colorado's air pollution laws; and
- Establish a mutually acceptable schedule and guidelines for the full and final resolution of any remaining deficiencies and noncompliance issues in a timely manner.

Please contact the Enforcement Advisor identified below by no later than March 9, 2022 to schedule a meeting with the Division to discuss the Compliance Advisory. In accordance with § 25-7-115(3)(a), C.R.S., the Compliance Advisory meeting will be held within thirty (30) days of the Division's issuance of the Compliance Advisory in this matter.

Jeremy Schuster, Enforcement Advisor (303-692-3131; jeremy.schuster@state.co.us)

To ensure meaningful communication with all Coloradans, the Division offers free language services. Please let us know if we can provide an interpreter for anyone attending the Compliance Advisory meeting.

cc: Shannon McMillan, APCD
Jennie Morse, APCD
Heather Wuollet, APCD
Chris Laplante, APCD
Michael Stovern, EPA (Region VIII)
File
Craig Giesecke, APCD
Jen Mattox, APCD
Tom Lovell, APCD
Sydney McLeod, LCDHE
Tom Roan, Attorney General's Office

COLORADO
Department of Public Health & Environment

AIR POLLUTION CONTROL DIVISION

COMPLIANCE ADVISORY

CASE NO. 2022-155
AIRS NO. 069-0180
INSPECTION DATE: April 21, 2022

U.S. CERTIFIED MAIL NO. 7012 1640 0000 0803 1832
MAILING DATE: August 9, 2022
SOURCE CONTACT: Ward Giltner

IN THE MATTER OF PROSPECT ENERGY, LLC

This Compliance Advisory provides formal notice, pursuant to § 25-7-115(2), C.R.S., of alleged violations or noncompliance discovered during the Air Pollution Control Division's ("Division") inspection and/or review of records related to Prospect Energy, LLC's Facility identified below. The Division is commencing this action because it has cause to believe that the compliance issues identified below may constitute violations of the Colorado Air Pollution Prevention and Control Act ("the Act") and its implementing regulations.

Please be aware that you are responsible for complying with applicable State air pollution requirements and that there are substantial penalties for failing to do so. Pursuant to the enforcement authority provided the Division by § 25-7-115, C.R.S., any person who violates the Act, its implementing regulations or any permit issued thereunder may be issued an order for compliance that can include permit revocation and assessment of penalties in accordance with § 25-7-122, C.R.S. The issuance of this Compliance Advisory does not in any way limit or preclude the Division from pursuing additional enforcement options concerning this inspection/review. Also, this Compliance Advisory does not constitute a bar to enforcement action for violations not specifically addressed in this Compliance Advisory.

Failure to respond to this Compliance Advisory by the date indicated at the end of this Compliance Advisory may be considered by the Division in the subsequent enforcement action and the assessment of penalties. Furthermore, the Division's enforcement process contemplates a full and final resolution of the compliance issues herein addressed, and those that may result from further review, in a timely manner. If at any time throughout the process of reaching such a resolution the Division determines that the Parties cannot agree to the dispositive facts, compliance requirements and/or penalty assessments (if any) associated with this Compliance Advisory, or a resultant enforcement action, the Division may exercise its full enforcement authority allowed under the law.

Prospect Energy, LLC ("Prospect") owns and operates the Fort Collins Tank Battery, an oil and gas well production facility located at NWNW Section 30, Township 8N, Range 68W, Larimer County, Colorado ("Facility"). The Facility is subject to the terms and conditions of Colorado Construction Permit Number 19LR0686, Issuance 1 issued to Prospect on October 28, 2019, Final Approval issued May 4, 2020 ("Permit Number 19LR0686"); Colorado General Construction Permit Number GP05, Version 3 ("GP05"); Colorado General Construction Permit Number GP08, Version 2 ("GP08"); Colorado Air Quality Control Statutes; and Colorado Air Quality Control Commission ("AQCC") Regulations. The following emissions points located at the Facility are relevant to this enforcement action:

AIRS Point	Point Description	Permit Number
002	Four (4) 500 bbl crude oil storage tanks, controlled by an enclosed combustor	GP08
003	Hydrocarbon liquid loading rack	N/A
004	Separator gas venting, controlled by an enclosed combustor	19LR0686
005	Two (2) 500 bbl and one (1) 300 bbl produced water storage tanks, controlled by an enclosed combustor	GP05

I. ALLEGED VIOLATIONS AND FACTS

On April 21, 2022, Sydney McLeod, of the Larimer County Department of Health and Environment, a duly delegated representative of the Division, inspected the Facility. Based on the inspection, and a review of records related to the Facility, the Division has identified the following compliance issues:

A. Pursuant to AQCC Regulation Number 3, Part A, § II.A.1, no person shall allow emission of air pollutants from, or construction, modification or alteration of, any facility, process, or activity which constitutes a stationary source, except residential structures, from which air pollutants are, or are to be, emitted unless and until an Air Pollutant Emission Notice ("APEN") and the associated APEN fee has been filed with the Division with respect to such emission. Until May 27, 2021, Prospect failed to file an APEN for the produced water tanks (AIRS Point 005), in violation of AQCC Regulation Number 3, Part A, § II.A.1.

B. Pursuant to AQCC Regulation Number 3, Part A, § II.C.1.e, a revised APEN shall be filed with the Division before the current APEN expires. Pursuant to AQCC Regulation Number 3, Part A, § II.C.3.a, a revised APEN shall be submitted no later than thirty days before the five-year term expires. Prospect previously submitted an APEN for AIRS Point 002 on April 26, 2016, and a revised APEN was due no later than March 27, 2021. Additionally, Prospect previously submitted an APEN for AIRS Point 003 on March 10, 2011, and a revised APEN was due no later than February 9, 2016. Prospect failed to submit revised APENs for AIRS Points 002 and 003 until May 27, 2021, in violation of AQCC Regulation Number 3, Part A, §§ II.C.1.e and II.C.3.a.

C. Pursuant to AQCC Regulation Number 3, Part B, § II.A.1, no person shall construct, modify, or operate any stationary source or commence the conduct of any such activity without first obtaining or having a valid construction permit from the Division. Until May 27, 2021, Prospect failed to obtain a construction permit for the produced water tanks (AIRS Point 005), in violation of AQCC Regulation Number 3, Part B, § II.A.1.

D. Pursuant to AQCC Regulation Number 7, Part D, § I.C.1.b; GP05, Condition IV.B.3; and GP08, Condition IV.B, all hydrocarbon liquids and produced water collection, storage, processing, and handling operations, regardless of size, must be designed, operated, and maintained so as to minimize emission of volatile organic compounds to the atmosphere to the maximum extent practicable. On May 9, 2022, a failure with the water level control system at the Facility resulted in the excessive build-up of produced water in the produced water tanks (AIRS Point 005). The produced water tanks overflowed, causing produced water to flow into the Facility's Tornado TEC-4-CS enclosed combustion device (ECD), resulting in a fire and visible emissions from the ECD. On May 9, 2022, Prospect failed to operate and maintain hydrocarbon liquid and produced water storage operations so as to minimize emission of volatile organic compounds to the atmosphere to the maximum extent practicable, violating AQCC Regulation Number 7, Part D, § I.C.1.b; GP05, Condition IV.B.3; and GP08, Condition IV.B.

E. Pursuant to AQCC Regulation Number 7, Part D, § I.C.1.d; Permit Number 19LR0686, Condition 13; GP05, Condition IV.A; and GP08, Condition IV.A.2, if a flare or other combustion device is used to control emissions of volatile organic compounds, it must be enclosed, have no visible emissions, and be designed so that an observer can, by means of visual observation from the outside of the enclosed flare or combustion device, or by other convenient means, such as a continuous monitoring device, approved by the Division, determine whether it is operating properly. On May 9, 2022, visible emissions were observed coming from the Facility's Tornado TEC-4-CS enclosed combustion device. Therefore, Prospect failed to ensure that the combustion device at the Facility had no visible emissions, violating AQCC Regulation Number 7, Part D, § I.C.1.d; Permit Number 19LR0686, Condition 13; GP05, Condition IV.A; and GP08, Condition IV.A.2.

F. Pursuant to AQCC Regulation Number 7, Part D, § II.E.4.d, Prospect must inspect Facility components for leaks using an approved instrument monitoring method (AIMM). Pursuant to AQCC Regulation Number 7, Part D, § II.E.4.g, the estimated uncontrolled actual VOC emissions from the highest emitting storage tank at the Facility determines the frequency at which inspections must be performed. The Facility is located within 1,000 feet of an occupied area. Based on reported VOC emissions, the crude oil tanks (AIRS Point 002) had uncontrolled VOC emissions between 2 and 12 tons per year in all rolling 12-month periods in 2020. The Facility was therefore subject to quarterly AIMM inspections in 2020. Thereafter, the produced water tanks (AIRS Point 005) had uncontrolled VOC emissions greater than 12 tons per year in all rolling 12-month periods from January 2021 through at least March 2022. Therefore, the Facility was subject to monthly AIMM inspections in 2021 through at least March 2022. Prospect failed to complete quarterly AIMM inspections in the second, third, and fourth quarters of 2020; and failed to complete monthly AIMM inspections in January, February, April, May, July, August, October, and November of 2021, violating AQCC Regulation Number 7, Part D, § II.E.4.d.

G. Pursuant to Permit Number 19LR0686, Condition 11 and GP05, Condition II.B.2, the permit number and ten digit AIRS ID number assigned by the Division shall be marked on AIRS Points 004 and 005 for ease of identification. At the time of the inspection on April 21, 2022, AIRS Points 004 and 005 were not marked with the applicable permit numbers or AIRS ID numbers. Prospect failed to mark AIRS Points 004 and 005 with the applicable permit numbers and AIRS IDs, violating Permit Number 19LR0686, Condition 11 and GP05, Condition II.B.2.

Prospect marked AIRS Points 004 and 005 following the inspection on April 21, 2022.

H. Pursuant to GP05, Condition V.B.4 and V.B.4.b, Prospect must maintain records that clearly demonstrate compliance with the emission limits in the permit. Compliance with emission limits must be determined by recording the annual emissions from each emission unit on a rolling 12-month total. Prospect provided the Division with Facility emissions records for the inspection conducted on April 21, 2022. Upon review of the provided records, the Division found that rolling 12-month emissions were calculated inaccurately for the produced water tanks (AIRS Point 005). Prospect failed to accurately calculate emissions and provide the Division with an accurate emissions compliance record for the Facility, violating GP05, Condition V.B.4 and V.B.4.b.

It is important to resolve the above-referenced issues as soon as possible. Therefore, the Division encourages Prospect to immediately identify those compliance issues that are not in dispute and to rectify those issues before the upcoming Compliance Advisory meeting. The Division also requests that Prospect provide the Division with a brief written response to the alleged violations ("Source Response"). The Source Response should identify the undisputed compliance issues and, if an alleged violation is disputed, the basis for the dispute. The Division requests that Prospect provide the Source Response, to the attention of Jeremy Schuster, no later than ten business days before the Compliance Advisory meeting. At the upcoming meeting, the Division will confirm the actions taken to rectify the undisputed compliance issues and proceed with unresolved matters as outlined below.

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- Submit information necessary to successfully show that the deficiencies and noncompliance issues (or any portion of them) are not violations of Colorado's air pollution laws; and
- Establish a mutually acceptable schedule and guidelines for the full and final resolution of any remaining deficiencies and noncompliance issues in a timely manner.

Please contact the Enforcement Advisor identified below by no later than August 16, 2022 to schedule a meeting with the Division to discuss the Compliance Advisory. In accordance with § 25-7-115(3)(a), C.R.S., the Compliance Advisory meeting will be held within thirty (30) days of the Division's issuance of the Compliance Advisory in this matter.

Jeremy Schuster, Enforcement Advisor (303-692-3131; jeremy.schuster@state.co.us)

To ensure meaningful communication with all Coloradans, the Division offers free language services. Please let us know if we can provide an interpreter for anyone attending the Compliance Advisory meeting.

cc:	Shannon McMillan, APCD	Sydney McLeod, LCDHE
	Jennie Morse, APCD	Jen Mattox, APCD
	Heather Wuollet, APCD	Tom Lovell, APCD
	Craig Giesecke, APCD	Michael Stovern, EPA (Region VIII)
	Tom Roan, Attorney General's Office	File

COLORADO
Air Pollution Control Division
Department of Public Health & Environment

Dedicated to protecting and improving the health and environment of the people of Colorado

Via Certified Mail Number 7012 1640 0000 0803 1863

CEASE AND DESIST ORDER

ISSUED TO: Prospect Energy, LLC
Attn: Ward Giltner
1036 Country Club Estates Drive
Castle Rock, CO 80108
**Sent via email and certified mail*

IN THE MATTER OF: Krause Tank Battery, a well production facility located 4.2 miles northeast of Highway 14 and US Highway 287, Larimer County, Colorado
Facility AIRS ID 069-0173

August 24, 2022

Mr. Giltner:

Prospect Energy, LLC (Prospect) owns and operates oil and gas facilities located in Larimer and Weld Counties, within the ozone nonattainment area. One of these facilities, Krause Tank Battery (Facility AIRS ID 069-0173) is located in Larimer County and is the subject of two (2) open formal enforcement actions with the Colorado Air Pollution Control Division (Division) (Case Nos. 2021-119 and 2022-020). The Krause Tank Battery is located within 200 feet of at least one residence.

The Division, and its delegated representatives at Larimer County Health Department (County), have conducted at least eight inspections at the Krause Tank Battery since March 2021, many of which were in response to complaints regarding tank emissions and odors from nearby residents. Through the course of these inspections, the Division has noted or discovered several areas of non-compliance or compliance concerns at the Krause Tank Battery. These areas of non-compliance or compliance concerns relate to emissions from the storage vessels and odors related to the emission of hydrogen sulfide (H_2S) and associated health concerns. In addition to this Cease-and-Desist Order, the Division has provided notice of alleged violations in Case No. 2021-119 on December 6, 2021 and in Case No. 2022-020 on January 28, 2022, included as Attachments 1 and 2.

Illegal emissions from one or more tanks in violation of AQCC Regulation No. 7 have been observed by Division and/or County inspectors during several inspections. The Division notes that these illegal tank emissions are related to Prospect's failure to follow Storage Tank and

Vapor Control Systems Guidelines designed to ensure compliance with Regulation 7 requirements. Observations of illegal tank emissions have continued even after the formal enforcement actions were commenced in late 2021 and early 2022, with illegal tank emissions observed on March 3, 2022, June 17, 2022, and August 11, 2022. Identification of these ongoing issues indicates that Prospect has not taken the necessary steps to return the facility to compliance, prevent illegal tank emissions, and reduce odors from the facility related to the emission of hydrogen sulfide (H2S).

The following table documents the pattern of observed emissions in 2021 and 2022 and Company responses:

Investigation Date	Violation Observed	Description of Emission	Repair Method	Date of Repair
3/3/21	AQCC Regulation No. 7, Part D, § I.C.1.b ; AQCC Regulation No. 7, Part D, § II.C.2.a	Division observed emissions from all 4 Oil Tank Thief Hatches	Patches applied to tops of tank	3/4/21
11/15/21	AQCC Regulation No. 7, Part D, § I.C.1.b ; AQCC Regulation No. 7, Part D, § II.C.2.a	Division observed emissions from Three Produced Water Thief Hatches; Centermost Tank had a crack on top.	Patches applied; Replace all tanks	12/27/21
1/28/22	Regulation No. 2, Part A, § I.B,	Larimer County conducted odor reading which documented odors of 32:1 dilution threshold, in excess of standard (15:1)		
1/28/22	AQCC Regulation No. 7, Part D, § I.C.1.b ; AQCC Regulation No. 7, Part D, § II.C.2.a	Division observed emissions from one crude oil tank thief hatch	Prospect confirmed repair completed	2/9/22

3/3/22	AQCC Regulation No. 7, Part D, § I.C.1.b ; AQCC Regulation No. 7, Part D, § II.C.2.a	Division observed emissions from crude oil thief hatches 2, 3, & 4	Repairs attempted 3/4/22	3/4/22
6/17/22	AQCC Regulation No. 7, Part D, § I.C.1.b ; AQCC Regulation No. 7, Part D, § II.C.2.a	Division observed emissions from Two Oil Tank Thief Hatches	Thief hatch gaskets rolled. New gaskets installed	6/27/22
8/11/22	AQCC Regulation No. 7, Part D, § I.C.1.b ; AQCC Regulation No. 7, Part D, § II.C.2.a	Division observed emissions from all 4 Oil Tank Thief Hatches	Vapor line to enclosed combustion device to be replaced because "it was not operating optimally."	*August 25-26 (pending)*

The Division understands that Prospect Energy completed a steady state design analysis in June 2020, concluding that the Enclosed Combustion Device (ECD) was properly sized to handle all vapor sources from the crude oil and produced water storage tanks. Produced gas from the separator was also included as a vapor source; however the Division the accuracy of the inputs into design analysis calculations is subject to question in light of the pattern of illegal tank emissions described above. Given the pattern of illegal tank emissions observed from Krause, it appears that the critical operating parameters need review and potential re-evaluation.

Additionally, Prospect is not operating within its Operation and Maintenance Plan and Written Procedures for the Krause Tank Battery, submitted to the Division in February 2020. Again, the presence of illegal tank emissions raises Division concerns regarding the proper implementation of the Written Procedures. Specifically, Prospect failed to complete any predictive analysis or Root Cause Analysis as detailed in the Written Procedures. This component of Prospect's draft Written Procedures is required to fully demonstrate that emissions are not the result of VCS over-pressurization as required by Regulation No. 7, Part D, Section II.C.2.a. Further, while Prospect notified the Division of its commitment to following the Division's Vapor Control System Guidelines, the pattern of illegal tank emissions listed above and reported by Prospect for the November 2021 compliance evaluation, along with lack of evaluation of system performance consistent with the Written Procedures indicates that Prospect is not operating within the Vapor Control System Guidelines. In addition, information provided by Prospect to the Division in response to the formal enforcement action(s), complaint investigations, and emissions investigations, indicates that the Krause Tank Battery is not properly designed, operated or maintained to ensure compliance with Colorado Regulation No. 7, Part D, prohibition of venting and minimization of emissions to the maximum extent practicable.

In addition to the implementation issues described above, the Division has concerns that these Written Procedures are, as of the date of this letter, in draft form and not yet final. During the course of its enforcement actions, the Division discussed these and other questions with Prospect, and is awaiting sufficient reply and explanation to continue the approval process of Prospect's Written Procedures. This approval process and additional corrective action is detailed below.

Second, Larimer County observed odors in violation of Regulation No. 2 standards on January 28, 2022, as described in the table above. Following this Regulation No. 2 odor violation, the Division has received 14 distinct odor complaints since January 2022. During the June 17, 2022 inspection, the Division inspector's gas monitor alarmed for Hydrogen Sulfide (H2S), indicating unsafe levels of H2S gas at the facility were present, requiring he vacate the premises according to division standard inspection procedures. The detection of H2S above an alert threshold in an open air ambient environment is very rare based on Division experience. The presence of H2S detected in June 2022 represents a public welfare concern for the continued operation of the facility. The Division requested H2S concentrations information for both the crude oil and produced water tanks. Prospect has not provided crude oil H2S concentration due to improperly gauged tubes, and the produced water analysis completed on or about October 2020 has redacted the specific value for H2S concentration for the produced water tanks. The alarming of the Division inspectors' 4-way gas monitor near the oil tanks in June 2022, raises significant concerns as to the emission of this specific pollutant and whether it is accurately reported under Colorado Regulation No. 3.

Finally, on August 11, 2022, the Division conducted an inspection at the Krause Tank Battery. During this inspection, the Division observed illegal tank emissions from the thief hatches on all four (4) crude oil tanks, indicating illegal tank emissions are ongoing. Prospect's response to further questions did not adequately address the Division's operational concerns.

Based on information available to the Division, including that described above, the Division has determined that air pollutants from Prospect's Krause Tank Battery activities "is of such a nature as to cause extreme discomfort or that it is an immediate danger to the welfare of the public because such pollutants make habitation of residences or the conduct of businesses subject to the pollutants extremely unhealthy or disruptive."

Therefore, pursuant to the authority granted by Colorado Revised Statutes § 25-7-113, the Division hereby orders Prospect to cease & desist from operating the Krause Tank Battery, effectively immediately. Specifically, Prospect shall discontinue any and all activities at Krause Tank Battery that have actual or potential to emit air pollutants. Prospect may not recommence operation and the emission of pollutants at Krause Tank Battery unless and until Prospect demonstrates to the Division that the facility complies fully with AQCC Regulations.

Among other actions that may be identified through further investigation and discussion, Prospect must:

- Complete and submit a design analysis for the Krause Tank Battery for Division review and approval. Prospect must complete and submit this vapor control system (VCS) design analysis for the Krause Tank Battery by September 9, 2022. The VCS design analysis shall be developed in accordance with the Division's Storage Tank and Vapor Control Systems Guidelines, dated May 4, 2018. These VCS Guidelines are included as Attachment 3 to this Order. Prospect shall use the VCS design analysis to determine if the Krause Tank Battery's VCS is adequately designed and sized to handle the Krause Tank Battery's potential peak instantaneous vapor flow rate (PPIVFR). The design analysis shall include a description of all inputs used in flow rate calculations, data used to establish throughputs for those calculations, and the basis for those values, including manufacturer specification sheets.
- If the design analysis determines that the Krause Tank Battery is not adequately designed and sized, Prospect must determine and implement all necessary modifications (i.e. design modifications and/or implementation of revised operational practices) to reduce the PPIVFR, alter the frequency and duration of the PPIVFR, and/or increase the capacity of the VCS in accordance with the VCS Guidelines. Prospect must ensure that the VCS is designed, sized and/or operated to handle the PPIVFR. Prospect must implement any corrective action identified on a Division approved timeline, but no later than November 8, 2022.
- Prospect must finalize and submit Written Procedures for maintenance of the Krause Tank Battery consistent with the Air Pollution Control Division Vapor Control System Guidelines for Storage Tanks, issued May 2018 by the Division, for Division review and approval by no later than November 8, 2022.
- Prospect must complete and submit to the Division either an extended gas analysis or Draeger tube sampling results of the crude oil and produced water to determine H2S concentrations in both liquid streams by no later than September 26, 2022.

- Prospect must submit for Division review and approval a complete Odor Management Plan to ensure compliance with Regulation No. 2 odor regulations by no later than September 26, 2022.

Prospect is requested to contact the Division and schedule a meeting to discuss the facility and activities that are the subject of this Order. Please contact Jen Mattox (jennifer.mattox@state.co.us) or myself to schedule the meeting. The Division expects Prospect to contact the Division to schedule this meeting by August 31, 2022. In an effort to further this process, the Division expects Prospect to respond to any additional requests for information within 2 business days.

Sincerely,

Shannon McMillan
Compliance and Enforcement Program Manager
Air Pollution Control Division
shannon.mcmillan@state.co.us
720-295-6537 (google voice)

cc (electronic): Jen Mattox, APCD
Jennie Morse, APCD
Craig Giesecke, APCD
Sergio Guerra, APCD
Michael Ogletree, APCD
Garry Kaufman, APCD
Heather Wuollet, APCD
Jeremy Schuster, APCD
Trisha Oeth, CDPHE
Will Marshall, Attorney General's Office
Tom Roan, Attorney General's Office
Will Allen, Attorney General's Office
Mimi Larsen, Colorado Oil & Gas Conservation Commission
Lea Schneider, Larimer County Public Health
Cassie Archuleta, City of Fort Collins

Attachment 1

COLORADO
Air Pollution Control Division
Department of Public Health & Environment

Air Pollution Control Division
Field Inspection Report

County Code: 069		Source Code: 0173	
Date of Inspection: 11/15/2021		Date Report Submitted: 12/06/2021	
Inspector: Craig Giesecke			
Company Name: Prospect Energy, LLC		Facility Name: Krause Battery	
Site Location: 4.2 mi. NE of Hwy. 14 & Hwy. 287		County: Larimer	
Contact Person: Ward Giltner		Phone Number: 303-489-8773	
Permit Number: GP05		Time: 10:00 a.m.	
Company Mailing Address: 1036 Country Club Estates Drive, Castle Rock, CO 80108			
Source Class: Synthetic Minor			
Inspection Type: PCE			
Travel and Prep: 2.0	Hours Inspection: 1.0	Hours Report: 7.0	Total Hours: 10.0
Applicable Subparts (NSPS/MACT): N/A			
Compliance Status: NOT in compliance			

Compliance History:
No previous INOVs for this facility.

Description of Source and Inspection Summary
On November 15, 2021, Craig Giesecke, of the Air Pollution Control Division ("Division"), conducted a partial compliance evaluation ("PCE") inspection of the Krause Battery ("Facility"), owned and operated by Prospect Energy, LLC ("Company"). The PCE was conducted as part of an investigation stemming from a complaint received by the Division on November 12, 2021. The Facility is an unmanned well production facility, and consists of the following emissions points:

AIRS Point	Permit Number	Point Description
002	GP08	Four (4) 300 bbl crude oil storage tanks, controlled by an enclosed combustor.
003	11LR1428.XP	Crude oil loading operations, uncontrolled.
004	19LR0685	Venting of gas from a 3-phase separator to an enclosed combustor.
005	GP05	Three (3) produced water storage tanks, controlled by an enclosed combustor. Tanks identified as **West** (300 bbl), and **Center** and **East** (400 bbl each).

At the time of the inspection Mr. Giesecke was not accompanied by any company personnel. Upon arrival to the Facility, Mr. Giesecke observed with the IR camera emissions coming from two (2) of the three (3) produced water storage tanks. Upon closer observation, he determined that there were emissions from each thief hatch on the Center and East produced water tanks. He also observed emissions from a patched area on the roof of the Center produced water tank. He then completed an inspection of the entire Facility with the IR Camera to look for any additional issues. A rotten egg smell was noted near an equipment shed at the base of the water tanks, though no emissions were observed with the IR camera from the shed's open door nor from any equipment visible inside. No odor was detected from beyond the Facility fence line. Emissions observed with the IR camera appeared to be intermittent and fluctuated over the duration of Mr. Giesecke's inspection. Mr. Giesecke recorded a video of produced water storage tank emissions using the IR Camera. Mr. Giesecke entered the inspection details in the Division's IR Camera System and notified the Company of the issues on November 16, 2021.

In a phone conversation on November 23, 2021, the Company's environmental consultant indicated to Mr. Giesecke that from March 2, 2021 to September 16, 2021, the Company had completed approximately five (5) repair attempts on the Center tank using fiberglass patching, and that the patches were repeatedly ineffective at reliably preventing emissions from what were determined to be crack(s) or hole(s) in the Center tank. Prior to the Division's November 15, 2021 inspection, the Center tank was most recently patched September 16, 2021. The Company completed another patch repair on November 24, 2021. The Company has purchased two (2) new fiberglass storage tanks to replace the Center and East tanks, and anticipates having them in operation by mid-December. The Company indicated that it is infeasible to shut in the site or isolate the Center tank as that would result in the potential for water lines to freeze and that shutting in would not stop the emissions since the tank would still contain liquids.

The Facility is located in the 8-hour ozone nonattainment area and is subject to Regulation No. 7, Part D § I.C. Furthermore, uncontrolled actual emissions from the produced water storage tanks are greater than 2 tpy VOC (as identified in the most recent APEN, received May 27, 2021) and therefore are subject to Regulation No. 7, Part D § II.C.1. Pursuant to Regulation No. 7, Part D § II.C.2.a.(i)(B), venting is emissions from a controlled storage tank thief hatch, pressure relief device, or other access point to the storage tank, which are the result of an open, unlatched, or visibly unseated pressure relief device (e.g., thief hatch or pressure relief valve), an open vent line, or an unintended opening in the storage tank (e.g., crack or hole). Though emissions were observed from both thief hatches and an unintended opening, this PCE is intended to specifically address the cracked tank while further information is gathered to evaluate emissions from the thief hatches. Additional evaluation of the thief hatch emissions will follow through another inspection report.

Based on the physical inspection of the Facility, the Company is NOT in compliance with the following requirements of AQCC Regulation No. 7, Part D §§ I and II:

A. Pursuant to AQCC Regulation No. 7, Part D § I.C.1.b, all hydrocarbon liquids and produced water collection, storage, processing, and handling operations, regardless of size, must be designed, operated, and maintained so as to minimize emission of volatile organic compounds to the atmosphere to the maximum extent practicable. As described above, the Company failed to minimize leakage of volatile organic compounds to the atmosphere to the maximum extent practicable, violating AQCC Regulation No. 7, Part D § I.C.1.b.

B. Pursuant to AQCC Regulation No. 7, Part D § II.C.2.a, owners or operators of storage tanks must route all hydrocarbon emissions to air pollution control equipment, and must operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation, unless venting is reasonably required for maintenance, gauging (unless the use of a storage tank measurement system is required pursuant to and the operator compiles with Section II.C.4.), or safety of personnel and equipment. As described above, the Company failed to operate without venting hydrocarbon emissions, violating AQCC Regulation No. 7, Part D § II.C.2.a.

Mr. Giesecke recommends the issuance of an Immediate Notice of Violation to resolve the violations found as a result of the inspection.

COLORADO
Air Pollution Control Division
Department of Public Health & Environment

AIR POLLUTION CONTROL DIVISION

IMMEDIATE NOTICE OF VIOLATION CASE NO. 2021-119

MAILING DATE: 12/06/21

IN THE MATTER OF Prospect Energy, LLC

The Colorado Department of Public Health and Environment ("CDPHE"), through the Air Pollution Control Division ("Division"), issues this Immediate Notice of Violation to Prospect Energy, LLC (the "Company") pursuant to the Division's authority under §25-7-115(2), C.R.S.

I. ALLEGED FINDINGS OF FACT AND VIOLATIONS

1. The Division issues this Immediate Notice of Violation following a partial compliance evaluation ("PCE") of the Company's facility located at 4.2 mi. NE of Hwy. 14 & Hwy. 287 (the "Facility") in Larimer County. The Facility is subject to statutes and regulations including, but not limited to, the Colorado Air Quality Control Statutes and Colorado Air Quality Control Commission ("AQCC") Regulations.

2. The Division conducted a PCE of the Facility on November 15, 2021. The inspection was performed by Craig Giesecke, Field Enforcement Officer with the Division's Oil and Gas Program.

3. Based upon that PCE, and a review of certain records related to the Facility, the Division has identified the following alleged violation(s):

A. Pursuant to AQCC Regulation No. 7, Part D § I.C.1.b, all hydrocarbon liquids and produced water collection, storage, processing, and handling operations, regardless of size, must be designed, operated, and maintained so as to minimize emission of volatile organic compounds to the atmosphere to the maximum extent practicable. On November 15, 2021, Craig Giesecke observed emissions from a crack or hole in the roof of the center produced water storage tank, which has been ineffectively repaired since at least March 2, 2021. The Company failed to minimize leakage of volatile organic compounds to the atmosphere to the maximum extent practicable, violating AQCC Regulation No. 7, Part D § I.C.1.b.

B. Pursuant to AQCC Regulation No. 7, Part D § II.C.2.a, owners or operators of storage tanks must route all hydrocarbon emissions to air pollution control equipment, and must operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation, unless venting is reasonably required for maintenance, gauging (unless the use of a storage tank measurement system is required pursuant to and the operator compiles with Section II.C.4.), or safety of personnel and equipment. On November 15, 2021, Craig Giesecke observed emissions from a crack or hole in the roof of the center produced water storage tank, which has been ineffectively repaired since at least March 2, 2021. The Company failed to operate without venting hydrocarbon emissions, violating AQCC Regulation No. 7, Part D § II.C.2.a.

II. PENALTY PROVISIONS

4. Pursuant to the enforcement authority provided the Division by § 25-7-115, C.R.S., any person who violates the Act, its implementing regulations or any permit issued thereunder may be issued an order for compliance that can include permit revocation and assessment of penalties in accordance with § 25-7-122, C.R.S.

5. Section 25-7-115(5), C.R.S., requires the Division to determine if a noncompliance penalty is applicable. If applicable, the Division may assess the penalty for any period of violation from the date that non-compliance began until the date on which compliance is achieved.

III. CONFERENCE REGARDING THE ALLEGED VIOLATIONS

6. In accordance with § 25-7-115(3), C.R.S., the Company is entitled to meet with the Division within thirty days of the effective date of this Immediate Notice of Violation in order for the Division to assess the alleged noncompliance and evaluate whether a noncompliance penalty must be assessed. The purpose of this conference is to permit the Company an opportunity to submit data, views, and arguments

concerning the alleged violation or noncompliance or the assessment of any noncompliance penalty. The Division strongly encourages the Company to submit its data, views, and arguments in writing within the thirty day time period in lieu of an in-person conference. However, should the Company wish to conduct the conference in-person, the Division is available to meet. Should the Company wish to attend an in-person conference, please contact Shannon McMillan, phone number 303-692-3259, to schedule the meeting. The Company is encouraged to submit a written response to this Immediate Notice of Violation prior to any scheduled conference. Upon completion of the investigation, the Division will determine how to close out this case and may assess civil and/or noncompliance penalties, as appropriate.

7. If the Company fails to contact the Division within thirty days of the effective date of this Immediate Notice of Violation, the Division may issue a Compliance Order and may assess penalties against the Company. Subsequent violation of the Compliance Order may subject the Company to further enforcement action under §§ 25-7-121 and -122, C.R.S.

IV. DATE OF NOTICE

8. This Immediate Notice of Violation serves as notice under § 25-7-115(2), C.R.S., and is considered effective upon December 6, 2021.

Electronic cc:

Shannon McMillan, APCD
Chris Laplante, APCD
Jennifer Mattox, APCD
Jennifer Morse, APCD
Heather Wuollet, APCD
Tom Lovell, APCD
Tom Roan, Office of Attorney General
Michael Stovern, US EPA

Attachment 2

AIR POLLUTION CONTROL DIVISION

COMPLIANCE ADVISORY

CASE NO. 2022-020
AIRS NO. 069-0173
INSPECTION DATES: November 15, 2021
January 28, 2022

SENT VIA ELECTRONIC MAIL
MAILING DATE: March 2, 2022
SOURCE CONTACT: Ward Giltner

IN THE MATTER OF PROSPECT ENERGY, LLC

This Compliance Advisory provides formal notice, pursuant to § 25-7-115(2), C.R.S., of alleged violations or noncompliance discovered during the Air Pollution Control Division's ("Division") inspection and/or review of records related to Prospect Energy, LLC's Facility identified below. The Division is commencing this action because it has cause to believe that the compliance issues identified below may constitute violations of the Colorado Air Pollution Prevention and Control Act ("the Act") and its implementing regulations.

Please be aware that you are responsible for complying with applicable State air pollution requirements and that there are substantial penalties for failing to do so. Pursuant to the enforcement authority provided the Division by § 25-7-115, C.R.S., any person who violates the Act, its implementing regulations or any permit issued thereunder may be issued an order for compliance that can include permit revocation and assessment of penalties in accordance with § 25-7-122, C.R.S. The issuance of this Compliance Advisory does not in any way limit or preclude the Division from pursuing additional enforcement options concerning this inspection/review. Also, this Compliance Advisory does not constitute a bar to enforcement action for violations not specifically addressed in this Compliance Advisory.

Failure to respond to this Compliance Advisory by the date indicated at the end of this Compliance Advisory may be considered by the Division in the subsequent enforcement action and the assessment of penalties. Furthermore, the Division's enforcement process contemplates a full and final resolution of the compliance issues herein addressed, and those that may result from further review, in a timely manner. If at any time throughout the process of reaching such a resolution the Division determines that the Parties cannot agree to the dispositive facts, compliance requirements and/or penalty assessments (if any) associated with this Compliance Advisory, or a resultant enforcement action, the Division may exercise its full enforcement authority allowed under the law.

Prospect Energy, LLC ("Prospect") owns and operates the Krause Tank Battery, a well production facility located 4.2 miles northeast of Highway 14 and US Highway 287, Larimer County, Colorado ("Facility"). The Facility is subject to the terms and conditions of Colorado Construction Permit Number 19LR0685, Issuance 1 issued to Prospect on October 28, 2019, Final Approval issued September 3, 2020 ("Permit Number 19LR0685"); Colorado General Construction Permit Number GP05, Version 3, Final Approval issued January 24, 2020 ("GP05"); Colorado Air Quality Control Statutes; and Colorado Air Quality Control Commission ("AQCC") Regulations. The following emissions points located at the Facility are relevant to this enforcement action:

AIRS Point	Point Description	Permit Number
002	Four (4) 300 bbl atmospheric crude oil storage tanks, controlled by an enclosed combustor.	GP08
003	Crude oil loadout operations, controlled by an enclosed combustor.	11LR1428.XP
004	Separator gas venting, controlled by an enclosed combustor.	19LR0685
005	Two (2) 400 bbl and one (1) 300 bbl produced water storage tanks, controlled by an enclosed combustor.	GP05

I. ALLEGED VIOLATIONS AND FACTS

On November 15, 2021, January 28, 2022, and February 8, 2022, Craig Giesecke, of the Division, inspected the Facility. On January 28, 2022, Sydney McLeod, of the Larimer County Department of Health and Environment, a duly delegated representative of the Division, conducted an odor observation at the Facility. Based on the inspections, and a review of records related to the Facility, the Division has identified the following compliance issues:

A. Pursuant to AQCC Regulation Number 3, Part A, § II.A.1, no person shall allow emission of air pollutants from, or construction, modification or alteration of, any facility, process, or activity which constitutes a stationary source, except residential structures, from which air pollutants are, or are to be, emitted unless and until an Air Pollutant Emission Notice ("APEN") and the associated APEN fee has been filed with the Division with respect to such emission. Prospect failed to file an APEN for the produced water tanks at the Facility (now AIRS Point 005) until May 27, 2021, in violation of AQCC Regulation 3, Part A, § II.A.[1]

B. Pursuant to AQCC Regulation Number 3, Part A, § II.C.1.e, a revised APEN shall be filed with the Division before the current APEN expires. Pursuant to AQCC Regulation Number 3, Part A, § II.C.3.a, a revised APEN shall be submitted no later than thirty days before the five-year term expires. Prospect submitted an APEN for AIRS Point 002 on January 4, 2016, and a revised APEN was due no later than December 5, 2020. Prospect failed to submit a revised APEN for AIRS Point 002 until May 27, 2021, in violation of AQCC Regulation Number 3, Part A, §§ II.C.1.e and II.C.3.a.

C. Pursuant to AQCC Regulation Number 3, Part B, § II.A.1, no person shall construct, modify, or operate any stationary source or commence the conduct of any such activity without first obtaining or having a valid construction permit from the Division. Prospect failed to obtain a permit for the produced water tanks at the Facility (now AIRS Point 005) until May 27, 2021, in violation of AQCC Regulation 3, Part B, § II.A.1.[1]

D. Pursuant to AQCC Regulation Number 7, Part D, § I.C.1.b, all hydrocarbon liquids and produced water collection, storage, processing and handling operations, regardless of size, must be designed, operated and maintained so as to minimize leakage of volatile organic compounds to the atmosphere to the maximum extent practicable. The following emissions were observed at the Facility:

[1] The produced water tanks were previously APEN and permit exempt. Prospect reported uncontrolled actual VOC emissions of 44.7 tons per year in the APEN submitted on May 27, 2021, based on 2020 emissions data.

Date emissions observed	Location of emissions	Repair date
1/28/2021	East PW TH	1/29/2021
3/2/2021	Oil #1 TH	3/4/2021
3/2/2021	Oil #2 TH	3/4/2021
3/2/2021	Oil #3 TH	3/4/2021
3/2/2021	Oil #4 TH	3/4/2021
3/2/2021	East PW TH	3/2/2021
3/2/2021	East PW roof (holes)	3/5/2021
3/2/2021	Center PW TH	3/2/2021
3/2/2021	Center PW roof (holes)	3/5/2021
3/31/2021	Oil #1 TH	4/1/2021
6/7/2021	East PW TH	1/12/2022
6/7/2021	East PW roof (holes)	1/12/2022
6/7/2021	Center PW TH	1/31/2022
6/7/2021	Center PW roof (holes)	1/31/2022
6/7/2021	Oil #3 TH	6/9/2021
6/7/2021	Oil #4 TH	6/9/2021
9/13/2021	East PW roof (holes)	1/12/2022
9/13/2021	Center PW roof (holes)	1/31/2022
11/15/2021	East PW TH	1/12/2022
11/15/2021	Center PW TH[2]	1/31/2022
1/28/2022	Oil #3 TH	2/9/2022

As indicated above, Prospect failed to operate and maintain hydrocarbon liquid and produced water storage operations so as to minimize leakage of volatile organic compounds to the atmosphere to the maximum extent practicable, violating AQCC Regulation Number 7, Part D, § I.C.1.b.

E. Pursuant to AQCC Regulation Number 7, Part D, § XVII.C.2.a (2019) and AQCC Regulation Number 7, Part D, § II.C.2.a (2020), for storage tanks, Prospect must route all hydrocarbon emissions to air pollution control equipment, and must operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or

[2] On December 6, 2021, the Division issued an Immediate Notice of Violation (INOV) to Prospect regarding this emission observation.

pressure relief device during normal operation, unless venting is reasonably required for maintenance, gauging, or safety of personnel and equipment. Pursuant to AQCC Regulation Number 7, Part D, § II.C.2.a.(iii) (2020), when venting is observed, Cub Creek must confirm within twenty-four (24) hours of taking action to return the storage tank to operation without venting that the action(s) taken was effective. The following emissions were observed at the Facility:

Date emissions observed	Location of emissions	Repair date
12/18/2019	Center PW TH	12/18/2019
1/28/2021	East PW TH	1/29/2021
3/2/2021	Oil #1 TH	3/4/2021
3/2/2021	Oil #2 TH	3/4/2021
3/2/2021	Oil #3 TH	3/4/2021
3/2/2021	Oil #4 TH	3/4/2021
3/2/2021	East PW TH	3/2/2021
3/2/2021	East PW roof (holes)	3/5/2021
3/2/2021	Center PW TH	3/2/2021
3/2/2021	Center PW roof (holes)	3/5/2021
3/31/2021	Oil #1 TH	4/1/2021
6/7/2021	East PW TH	1/12/2022
6/7/2021	East PW roof (holes)	1/12/2022
6/7/2021	Center PW TH	1/31/2022
6/7/2021	Center PW roof (holes)	1/31/2022
6/7/2021	Oil #3 TH	6/9/2021
6/7/2021	Oil #4 TH	6/9/2021
9/13/2021	East PW roof (holes)	1/12/2022
9/13/2021	Center PW roof (holes)	1/31/2022
11/15/2021	East PW TH	1/12/2022
11/15/2021	Center PW TH**Error! Bookmark not defined.**	1/31/2022
1/28/2022	Oil #3 TH	2/9/2022

As indicated above, Prospect failed to route all hydrocarbon emissions to air pollution control equipment and operate without venting hydrocarbon emissions from storage tank thief hatches and pressure relief devices. Additionally, for the emissions identified on June 7, 2021; September 13, 2021; and November 15, 2021, Prospect has failed to confirm that any action to return the applicable tanks to operation without venting was effective. Therefore, Prospect is in violation of AQCC Regulation Number 7, Part D, § XVII.C.2.a (2019); AQCC Regulation Number 7, Part D, § II.C.2.a (2020); and AQCC Regulation Number 7, Part D, § II.C.2.a.(iii) (2020).

F. Pursuant to AQCC Regulation Number 7, Part D, § II.E.4.d, beginning calendar year 2020, Prospect must inspect components for leaks using an approved instrument monitoring method (AIMM) in accordance with the inspection frequency in Table 3. Based on reported uncontrolled actual VOC emissions, Prospect was required to complete AIMM inspections on a quarterly basis from January 2020 through April 2021, and on a monthly basis beginning in May 2021[3]. Prospect failed to conduct AIMM inspections in the following periods:

Required AIMM frequency	Periods missed
Quarterly	January-March 2020
	April-June 2020
	July-September 2020
	October-December 2020
Monthly	May 2021
	July 2021
	August 2021
	October 2021

Prospect failed to complete required AIMM inspections, as shown in the table above, violating AQCC Regulation Number 7, Part D, § II.E.4.d

G. Pursuant to AQCC Regulation Number 2, Part A, § I.B, Prospect shall not cause or allow the emission of odorous air contaminants from any single source such as to result in odors that are detectable after the odorous air has been diluted with fifteen (15) or more volumes of odor free air (“15:1 d/t”). On January 28, 2022, Larimer County observed odors in excess of the 15:1 d/t limit, as detailed below.

[3] The Facility is located within 1,000 feet of an occupied area. Prior to May 2021, Prospect reported less than 12 tons per year of VOC emissions from the highest emitting storage tank at the Facility. In May 2021, Prospect submitted an APEN for AIRS Point 005, which included estimated annual uncontrolled actual VOC emissions above 12 tons per year; making the Facility then subject to monthly AIMM inspections.

Time	Odor reading	Location
12:30 PM	No odor detected	Upwind
1:10 PM	No odor detected	Upwind
1:30 PM	32:1	Downwind
1:31 PM	32:1	Downwind
1:50 PM	32:1	Downwind
2:00 PM	32:1	Downwind
2:08 PM	No odor detected	Upwind

On January 28, 2022, Prospect failed to ensure that emission of odorous air contaminants remained below the 15:1 d/t limit, violating AQCC Regulation Number 2, Part A, § I.B.

H. Pursuant to Permit Number 19LR0685, Condition 11 and GP05, Condition II.B.2, the permit number and ten digit AIRS ID number assigned by the Division shall be marked on AIRS Points 004 and 005 for ease of identification. Prospect has failed to mark the applicable permit numbers and AIRS IDs on AIRS Points 004 and 005, violating Permit Number 19LR0685, Condition 11 and GP05, Condition II.B.2.

It is important to resolve the above-referenced issues as soon as possible. Therefore, the Division encourages Prospect to immediately identify those compliance issues that are not in dispute and to rectify those issues before the upcoming Compliance Advisory meeting. The Division also requests that Prospect provide the Division with a brief written response to the alleged violations ("Source Response"). The Source Response should identify the undisputed compliance issues and, if an alleged violation is disputed, the basis for the dispute. The Division requests that Prospect provide the Source Response, to the attention of Jeremy Schuster, no later than ten business days before the Compliance Advisory meeting. At the upcoming meeting, the Division will confirm the actions taken to rectify the undisputed compliance issues and proceed with unresolved matters as outlined below.

If you have any questions regarding this Compliance Advisory, the Division's enforcement processes, or any related issues, please refer to the APCD Enforcement Guide located at https://www.colorado.gov/pacific/cdphe/inspections-and-enforcement and/or contact the Division personnel identified below.

II. COMPLIANCE ADVISORY MEETING

Prospect is requested to contact the Division and schedule a meeting to:

- Discuss the disputed Compliance Advisory issues and answer any remaining questions you may have;
- Submit information necessary to successfully show that the deficiencies and noncompliance issues (or any portion of them) are not violations of Colorado's air pollution laws; and
- Establish a mutually acceptable schedule and guidelines for the full and final resolution of any remaining deficiencies and noncompliance issues in a timely manner.

Please contact the Enforcement Advisor identified below by no later than March 9, 2022 to schedule a meeting with the Division to discuss the Compliance Advisory. In accordance with § 25-7-115(3)(a), C.R.S., the Compliance Advisory meeting will be held within thirty (30) days of the Division's issuance of the Compliance Advisory in this matter.

Jeremy Schuster, Enforcement Advisor (303-692-3131; jeremy.schuster@state.co.us)

To ensure meaningful communication with all Coloradans, the Division offers free language services. Please let us know if we can provide an interpreter for anyone attending the Compliance Advisory meeting.

cc:
Shannon McMillan, APCD
Jennie Morse, APCD
Heather Wuollet, APCD
Chris Laplante, APCD
Michael Stovern, EPA (Region VIII)
File
Craig Giesecke, APCD
Jen Mattox, APCD
Tom Lovell, APCD
Sydney McLeod, LCDHE
Tom Roan, Attorney General's Office

Attachment 3

COLORADO
Air Pollution Control Division
Department of Public Health & Environment

Storage Tank and Vapor Control Systems Guidelines

Design, Operation and Maintenance

May 4, 2018

Acknowledgments

This document was made possible by contributions from member companies of the Colorado Oil and Gas Association and Colorado Petroleum Association, along with staff from the Colorado Department of Public Health and Environment, Air Pollution Control Division and the Colorado Department of Law.

Thank you to the steering committee members, including:

- Jennifer Biever (Hogan Lovells)
- Andrew Casper (Colorado Oil & Gas Association)
- Randy Dann (Davis, Graham & Stubbs)
- Rusty Frishmuth (HighPoint Resources Corporation)
- Chelsea Grossi (Davis, Graham & Stubbs)
- Andrea Huggins (Whiting Oil and Gas Corporation)
- Clay Taylor (Whiting Oil and Gas Corporation and Colorado Petroleum Association)

A special thank you to James Van Horne, SLR International Corporation, Adam Meyer, ZAP Engineering and Construction Services, for their contributions to the technical content of this guidance.

Disclaimer

These guidelines are not rules or regulations adopted in accordance with the Administrative Procedure Act, nor do the guidelines modify, limit, or expand existing Colorado rules or regulations.

Table of Contents

1.0 Introduction

The Storage Tank and Vapor Control Systems Guidelines present recommendations for operators of storage tanks to demonstrate compliance with Colorado Air Quality Control Commission (AQCC) Regulation Number 7, Section XII.C.1.b, Section XVII.B.1.a, or Section XVII.C.2., as applicable. These guidelines also describe important technical and practical considerations for the design, operation, and maintenance of vapor control systems at oil and gas (O&G) facilities. Nothing herein is intended to mean that the standards established by Sections XII.C.1.b and XVII.B.1.a are equivalent.

While these guidelines were developed primarily for controlled storage tanks at well production facilities subject to the regulatory provisions referred to above, they may also be helpful for other O&G operations. The division intends these guidelines to be a useful resource for improving the performance of storage tank vapor control systems at any O&G facilities, whether or not required to be controlled by regulation or permit. Following these guidelines in whole or in part does not create a presumption that the storage tank(s) included are subject to these guidelines or subject to the regulatory requirements these guidelines discuss.

The guidelines describe considerations for design, operation, and maintenance of vapor control systems at Colorado O&G facilities, which are useful whether an operator employs a vapor control system as required by Regulation Number 7 or by permit, etc., or whether the operator voluntarily chooses to employ VCS to reduce emissions. The design guidelines provide methodology, recommendations, and support for O&G operators in the design and construction of vapor control systems, including the storage tanks and control devices. Key elements of the design guidelines include determination of appropriate modeling methods, calculation of peak instantaneous flow values, determination of design adequacy, and identification of critical parameters for initial and ongoing verification to be used as part of the operation and maintenance of the storage tank.

The operation and maintenance (O&M) guidelines are intended to provide both proactive and reactive measures to reduce the occurrence of emissions from storage tanks. Key elements of an O&M program include: preventative maintenance, operational practices, training, and recordkeeping.

These guidelines do not represent the only methods to comply with Regulation Number 7 requirements cited above, and language such as “should” or “will” (as used in this document) is not intended to suggest that these guidelines must be met in order to comply with Regulation Number 7 requirements. Further, any programmatic review contemplated by these guidelines does not automatically render an immunity request under Colorado statutes not voluntary within the meaning of C.R.S. § 25-1-114.5.

1.1 Purpose

The guidelines are intended to provide owners and operators with information to assist in designing, operating and maintaining storage tanks in accordance with the requirements of

Colorado law. They complement the Permit Section (PS) Memos and other information provided by the Air Pollution Control Division, which are available on the division's website. Further, nothing in these guidelines is intended to relieve owners and operators of O&G facilities of the responsibility to comply with all state and federal environmental laws, regulations, and permits.

Under Regulation Number 7, Sections XII.C.1.b. and XVII.B.1.a, as those rules relate to these guidelines, operators are required to minimize leakage from vapor control systems. Additionally, under Section XVII.C.2.a., certain storage tanks must be operated without venting. The division acknowledges that each of these provisions contemplates that there may be instances where emissions from the storage tanks do not constitute a violation. In determining when emissions from the storage tank constitutes a violation of these regulations, the division can require information from the operator regarding the cause of emissions and other relevant information sufficient to determine whether the operator has properly designed, operated and maintained the storage tank and vapor control system. These guidelines will aid in this determination by providing a set of criteria for proper design, operation and maintenance.

While there may be instances where conformance with the guidelines may not be enough to demonstrate compliance, the division expects that in most instances where emissions from storage tanks are observed, a showing by the owner or operator that it has followed these guidelines will be sufficient to establish the observed emissions do not constitute a violation of the "operate without venting" and "minimize leakage" requirements of Regulation Number 7. These guidelines are not intended to prescribe requirements and presume that owners and operators can tailor these approaches to their specific facilities to demonstrate compliance with applicable Colorado air quality statutes and regulations governing emissions from storage tanks. These guidelines do not restrict the division's discretion to pursue enforcement where it deems appropriate for alleged violations of the "operate without venting" or "minimize leakage" standards.

1.2 Revision of Guidelines

The guidelines are intended to be a living document. The division will periodically revisit these guidelines and make updates as necessary. Industry representatives (through the Colorado Oil and Gas Association) and other interested stakeholders will be given the opportunity to review and provide comment on material revisions before the guidelines are updated.

Operators will be provided time to implement revisions to the guidelines (as opposed to clarifications). Revisions to the guidelines do not, by themselves, render an operator's program prior to the revision incomplete or insufficient.

1.3 Implementation of Guidelines

The division intends that these guidelines will have varying timelines for implementation based on the number of facilities, historical approaches to design, operation and maintenance, and the current status of individual company programs. Design, operation, and maintenance procedures should already be in place for facilities already constructed; however, the division recognizes that operators may need time to improve or augment their programs and procedures.

In the second quarter of 2018, the division intends to participate in joint outreach with the industry stakeholders to increase awareness and to help Colorado operators understand how to apply these guidelines. The division encourages and invites operators to communicate with the division on their plan for implementing these guidelines for both existing sources and new sources that have yet to be constructed.

Operators are encouraged to bring questions regarding interpretation to the division to avoid disputes related to implementation of these guidelines.

1.4 Contacts

For more information on these guidelines, please visit:

https://www.colorado.gov/cdphe/air-oilandgas-storagetankguidelines.

At this webpage you may request a meeting with division staff, submit comments or questions, and see any other information published by the division regarding these guidelines.

2.0 Definitions and Acronyms

2.1 Acronyms

ACF	Actual Cubic Feet
AQCC	Colorado Air Quality Control Commission
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
BBL	Barrel of hydrocarbon liquid
CDPHE	Colorado Department of Public Health and Environment
FGOR	Flash Gas to Oil Ratio
FGWR	Flash Gas to Water Ratio
GPA	Gas Processors Association
ISA	International Society of Automation
MAWP	Maximum Allowable Working Pressure
MMSCFD	Million Standard Cubic Feet per Day
NPS	Nominal Pipe Size
O&M	Operating and Maintenance
PM	Preventative Maintenance
PPILFR	Potential Peak Instantaneous Liquid Flow Rate
PPIVFR	Potential Peak Instantaneous Vapor Flow Rate
PRD	Pressure Relief Device
PRV	Pressure Relief Valve

PS	Permit Section
PSI	Pounds per Square Inch
SCF	Standard Cubic Feet
STEM	Storage Tank Emission Management System
STP	Standard Temperature and Pressure
USEPA	United States Environmental Protection Agency
VCS	Vapor Control System
VOCs	Volatile Organic Compounds
VRT	Vapor Recovery Tower
VRU	Vapor Recovery Unit

2.2 Definitions

Actual Cubic Feet (ACF) means the volume of gas/vapor that exists within a vapor control system based on actual operating temperature and pressure.

API Gravity means an inverse measure of a petroleum liquid's density relative to that of water (also known as specific gravity (SG)), as recommended by the American Petroleum Institute (API). The API gravity is calculated as [(141.5/SG) - 131.5], where SG is the specific gravity of the fluid at 60°F relative to water at 60°F. API gravity values of most petroleum liquids fall between 10 and 70 degrees.

Breathing Losses or Breathing Emissions means losses that can occur when there are temperature or pressure fluctuations in the storage tank that volatilize lighter hydrocarbons (breathing). Breathing losses are sometimes also referred to as thermal or standing losses.

Bubble Point means the conditions (temperature and pressure) at which the pressurized liquid is just ready to evolve a vapor phase (i.e., boil). A crude oil or condensate mixture within a separator is considered to be at or near its bubble point.

Bubble Point Check means a pressurized hydrocarbon liquid sample quality control and quality assurance process where a comparison is made between the calculated bubble point temperature and pressure determined via the analysis of the pressurized hydrocarbon liquid sample composition and the temperature and pressure recorded during sampling. Refer to CDPHE PS Memo 17-01 for the acceptable tolerances for a pressurized sample bubble point check and when resampling or bubble point correction may be required.

Bubble Point Correction means a procedure where the composition of a pressurized liquid can be “corrected” to its bubble point at a given temperature and pressure.

Condensate means a hydrocarbon liquid that has an API Gravity greater than or equal to 40° API at 60° F. (PS Memo 05-01, Section 1.3)

Control Device means air pollution control equipment used to achieve VOC and hydrocarbon emission reductions; examples include, but are not limited to: an enclosed flare, a combustor, an enclosed combustion device, a vapor recovery unit, etc.

Critical Operating Parameter means those key design input parameters which have been determined during the design analysis to be critical to the ongoing operation of the vapor control system within the constraints of the design analysis. They are determined by the operator in conjunction with the design analyst. These critical operating parameters may be static or dynamic. (*See* Figure 6.2.)

Crude Oil means a hydrocarbon liquid that has an API gravity less than 40° API at 60° F. (PS Memo 05-01, Section 1.5)

Dump Event means an opening of a dump valve allowing liquid flow from a separator equipped with a dump valve to a storage tank.

Dump Valve means a liquid-control valve in a separator that controls liquid level within the separator vessel.

Emission Response Action means any action taken in response to observance of emissions from the VCS, which may occur at any time (*e.g.*, during inspections or PM). Examples of emission response actions may include:

- Repair or replacement of equipment at a single facility;
- Repair or replacement of similar equipment at a group of facilities;
- Change in frequency or description of preventative maintenance and/or inspections;
- Root cause analysis and implementation of resulting recommended emission response action;
- Revising operational practices;
- Revising a design evaluation; and/or
- Shut-in of the well(s).

Flame Arrestor means an in-line device that helps prevent flame propagation or detonation in the VCS by absorbing the heat from a flame front traveling at sub-sonic velocities, thus dropping the burning gas/air mixture below its auto-ignition temperature.

Flash or **Flashing** means the release of hydrocarbon vapors and other dissolved gases from hydrocarbon liquid due to a reduction in pressure or increase in temperature.

Flash Gas means vapor resulting from the flash of condensate, crude oil or produced water in a separator, VRT, storage tank or other vessel.

Flash Gas-Oil-Ratio (FGOR) means the ratio of the volume of flash gas produced from a volume of crude oil or condensate when depressurized to storage tank temperature and pressure (i.e., flashed). Typically reported in standard cubic feet per stock tank barrel of oil (SCF/BBL).

Flash Gas-Water-Ratio (FGWR) means the ratio of the volume of flash gas produced from a volume of produced water when depressurized to storage tank temperature and pressure (i.e., flashed). Typically reported in standard cubic feet per stock tank barrel of produced water (SCF/BBL).

Flash Liberation Analysis means the laboratory methodology in which a pressurized liquid sample is flashed under laboratory conditions designed to mimic field conditions. Analysis results are expressed as flash gas-oil-ratio or flash gas-water-ratio and typically include the composition and properties of the flash gas.

Follow-up maintenance action means any action taken in response to a PM activity in an operator's written procedures, without regard to whether emissions were observed. Examples of follow-up maintenance actions could include: cleaning gaskets, replacing or repairing parts, etc. A follow-up maintenance action could also be considered an "emission response action" as defined above, and in the case of any conflict between applicable provisions (*e.g.,* timing, recordkeeping, etc.), the more stringent provision would control.

Key Design Input Parameters means those variables that impact design evaluation and system performance, as identified by the design analyst.

Liquid Knockout Vessel means a vessel at or near atmospheric pressure used for separating a material stream into gaseous and liquid components. Commonly used upstream of a control device to prevent liquids from reaching the control device.

Malfunction means any sudden and unavoidable failure of air pollution control equipment or process equipment, or unintended failure of a process to operate in a normal or usual manner. Failures that are primarily caused by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions. (AQCC Common Provisions Regulation, Section I.G.) For purposes of clarification, emissions caused by inadequate design of a vapor control system are not malfunctions.

Potential Peak Instantaneous Liquid Flow Rate (PPILFR) means the maximum rate of flow of crude oil, condensate, or produced water discharged from the separator or VRT simultaneously entering the storage tank from all connected sources during normal operation, with a timescale identified by the discretion of the analyst. Utilized in conjunction with FGOR and/or FGWR to determine the flashing and working components of potential peak instantaneous vapor flow rate. The timescale of the PPILFR should represent the duration of the peak liquid flow.

Potential Peak Instantaneous Vapor Flow Rate (PPIVFR) means the maximum rate of flow of vapors to a vapor control system during normal operation, including flashing, working and breathing losses, as well as all other sources of vapor introduced to the vapor control system, with a timescale identified by the discretion of the analyst.

PPIVFR Duration means the length of time of peak flow of vapor into the storage tank.

PPIVFR Frequency means the rate of PPIVFR occurrences within a storage tank.

Pressure Relief Device (PRD) means a device installed in a storage tank or separator to protect the structural integrity of a storage tank, which includes, but is not limited to, thief hatches, pressure relief valves (PRV), and pressure vacuum relief valves.

Pressurized Liquids means pressurized crude oil, condensate, or produced water maintained at a pressure above ambient atmospheric pressure anywhere upstream of the atmospheric storage tank.

Produced Water means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction. It may contain various hydrocarbons.

Separator means a heated or unheated pressurized vessel designed to separate produced fluids into their constituent components of crude oil or condensate, natural gas, and produced water. May be 2-phase (separating liquid and vapor phases) or 3-phase (separating crude oil or condensate, natural gas, and produced water.) Heater treaters and VRTs are two types of separators.

Standard Temperature and Pressure means the API definition of standard conditions, 60 °F and 14.7 psia.

STEM Plan means the Storage Tank Emission Management System plan required to identify, evaluate, and employ appropriate control technologies, monitoring practices, operational practices, and/or other strategies designed to meet the requirements set forth in Section XVII.C.2.a. (AQCC Regulation Number 7, Section XVII.C.2.b)

Storage Tank means any fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. (AQCC Regulation Number 7, Section XVII.A.16)

Vapor Control System (VCS) means all vent lines, connectors, fittings, valves, relief valves, thief hatches, storage tanks and any vapor interconnected tanks, liquid knockout vessels, or any other appurtenance employed to contain and collect storage tank vapors (including flashing, working, and breathing emissions), as well as vapors from other sources connected to the system collecting storage tank vapors (such as compressor scrubbers, pneumatic devices, etc.) and transport or convey them to a control device. The VCS also includes the control device.

Vapor Recovery Tower (VRT) means a 2-phase separator located downstream of a separator and upstream of a storage tank used to reduce the pressure of liquids discharged from upstream separators prior to entering the storage tank to reduce creation of flash gas in tanks.

Volatile Organic Compounds (VOCs) means any compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates and ammonium carbonate, which participates in atmospheric photochemical reactions, except those designated by EPA as having negligible photochemical reactivity.

Working Losses or Working Emissions means losses that can occur as vapors are displaced from the storage tank headspace when the tank is filled.

3.0 Documentation

The division expects that the majority of records maintained will be described in the operator's written procedures. These written procedures can be in the form of standard operating procedures, Storage Tank Emission Management System (STEM) Plans, or other written documentation of the operator's standard practices.

The division anticipates that the written procedures and other written materials developed in response to these guidelines will be used for training those who will implement the operator's program in the field, and that the records maintained will enable both the operator and the division to determine whether the operator is following these guidelines and its written procedures. Chapters 5.0 and 6.0, below, provide more specific detail as to the division's expectations regarding appropriate documentation and recordkeeping.

3.1 Written Procedures

The division anticipates that these guidelines will provide a framework for operators to develop written procedures. These written procedures should include information on the programs described in these guidelines. Specifically, written procedures should capture:

- The procedures/methods for the program;
- The events or actions to be conducted;
- The frequency of events or actions;
- Recordkeeping practices and schedule;
- Plan for written procedure revisions or updates; and
- How the program will be implemented (field-wide and/or facility-specific).

Superseded versions should be maintained for five years.

3.2 Recordkeeping

In addition to the documents required by Regulation Number 7 and recommended by these guidelines, the division expects that operators will maintain any records identified in the operator's written procedures and any records required by state or federal regulation or permit. Unless otherwise specified herein or in Regulation Number 7, the division recommends retaining records (including written procedures) for a period of five years.

3.3 Storage Tank Emission Management System Plan

Storage Tank Emission Management System (STEM) Plans should address the elements of these guidelines explicitly or, in some cases, may refer to other company programs, systems, or records that address these elements. The STEM plan should document where programs and records are maintained, and records should be made available upon request by the division.

In addition to the specific requirements of Regulation Number 7, Section XVII.C.2.b., as further explained in the Statement of Basis and Purpose, STEM plans should include or refer to the following:

- The design analysis written procedures;
- The design analysis report;
- Summary of the predictive analysis results;
- All written procedures developed in accordance with these guidelines; and
- All records to be maintained in accordance with these guidelines.

STEM plans, and associated records (i.e., records appended to the STEM Plan containing the information specified in Regulation Number 7, the Statement of Basis and Purpose, or these Guidelines) should be maintained for the life of the storage tank.

4.0 Training

4.1 Employees, Contractors and Consultants

Operators should ensure that all employees, contractors or consultants responsible for implementation of these guidelines are made aware of, and have access to, these guidelines and appended or related company material necessary to implement the guidelines, including the operator's written procedures. The failure of a contractor or consultant to perform duties in accordance with these guidelines, or the operator's written materials implementing these guidelines, shall not be a defense to any action taken by the division.

4.2 Employees

Operators should train all employees responsible for performing any of the responsibilities described in these guidelines and in the operator's written materials implementing these guidelines. However, training may be appropriately tailored, so long as employees are trained on those aspects affecting or impacting the performance of his/her duties. For clarification, employees should be aware of the critical operating parameters, so as to avoid unintentional impacts on the validity of the design analysis. Training can include any combination of formal, informal, classroom, field, independent study, or other, as determined by the operator.

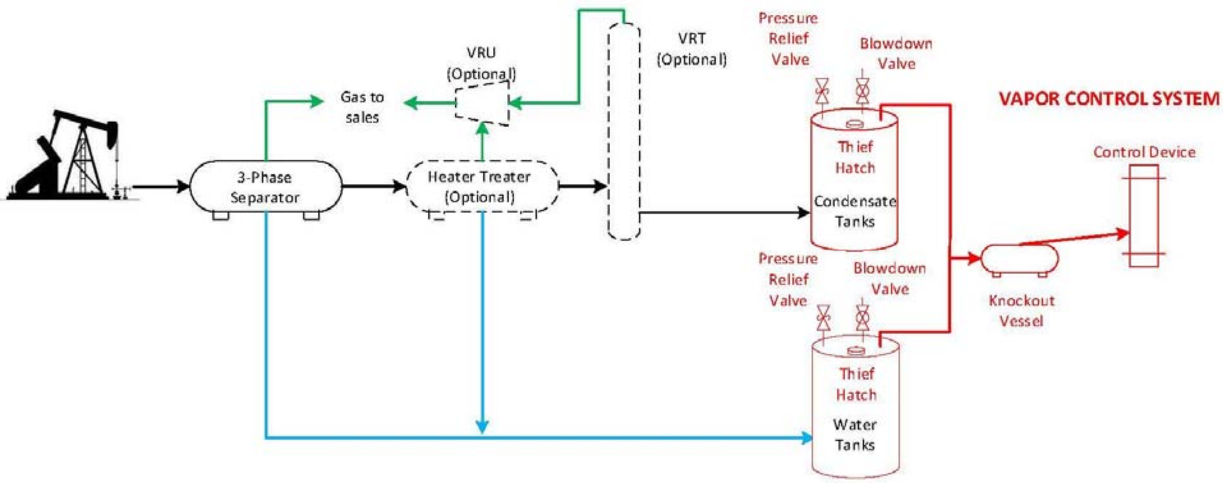
This training should cover the written procedures and should be provided to new personnel before they perform these activities and periodically thereafter (recommended at least annually). Operators should make the written procedures developed in accordance with these guidelines conveniently available to affected employees, and make employees aware of where the procedures can be accessed.

These guidelines do not create recordkeeping requirements with respect to documentation of a training program (*e.g.,* no certification that an employee has been through training), though the Division expects that the operator's written procedures will describe the operator's training program.

5.0 Design Guidelines

These design guidelines are intended to provide a general framework for oil and gas operators to conduct an evaluation of a VCS, ultimately ensuring and documenting that a facility is designed to minimize emissions. Nothing in these guidelines by itself creates an obligation for an operator to follow the design guidelines to ensure compliance with Regulation Number 7, particularly with respect to well production facilities that voluntarily employ a VCS. The division does not want to discourage operators from voluntarily controlling storage tanks.

Figure 5.1 Generalized Production Field Facility Schematic



There are two fundamental steps to complete an evaluation of an existing VCS or to properly design a new VCS.

Step 1: Estimate the Potential Peak Instantaneous Liquid Flow Rate (PPILFR) and the resulting Potential Peak Instantaneous Vapor Flow Rate (PPIVFR); and

Step 2: Determine whether the existing or newly designed VCS is adequately designed and sized to handle the PPIVFR in accordance with the requirements of Regulation Number 7, based on the estimations of PPILFR and PPIVFR.

These guidelines provide a set of overarching recommended practices, but the practices contained herein should be tailored to specific sites such that the differences in product stored, geographical location, process design and facility layout are accounted for properly.

5.1 Design Analysis

5.1.1 Types of Analysis

There are generally two analysis methods that can be employed to evaluate the design of a VCS: steady-state or transient.

Steady-State Analysis: In a steady-state model, the capacity of the storage tank vapor headspace to absorb flash gas is ignored, and it is assumed that all vapors entering or being generated in the storage tank are immediately managed by the control device with no increase in storage tank pressure. Hence, the system is in "steady-state". A steady-state modeling approach is generally easier to complete; however, it is a conservative approach that can result in oversizing of VCS equipment. This analysis type is commonly used when the PPIVFR is less than or equal to the VCS capacity, or when the VCS capacity is capable of continuously handling all of the PPIVFR. See Section 5.1.7 for a more detailed discussion of VCS capacity.

Transient Analysis: A transient (also known as dynamic) modeling approach takes into account all of the changing variables at play in a VCS. Both the outflow to a Control Device via the VCS and the buffering capacity of storage tank vapor headspace are taken into account. This analysis type is commonly used when the PPIVFR is greater than the VCS capacity, but the operator desires to demonstrate the storage tanks are able to fully contain the PPIVFR and associated tank pressure increase until the VCS is able to manage the accumulated vapor and reduce pressure in the storage tank.

5.1.2 Process Flow Diagram

Figure 5.2 Steady-State Analysis

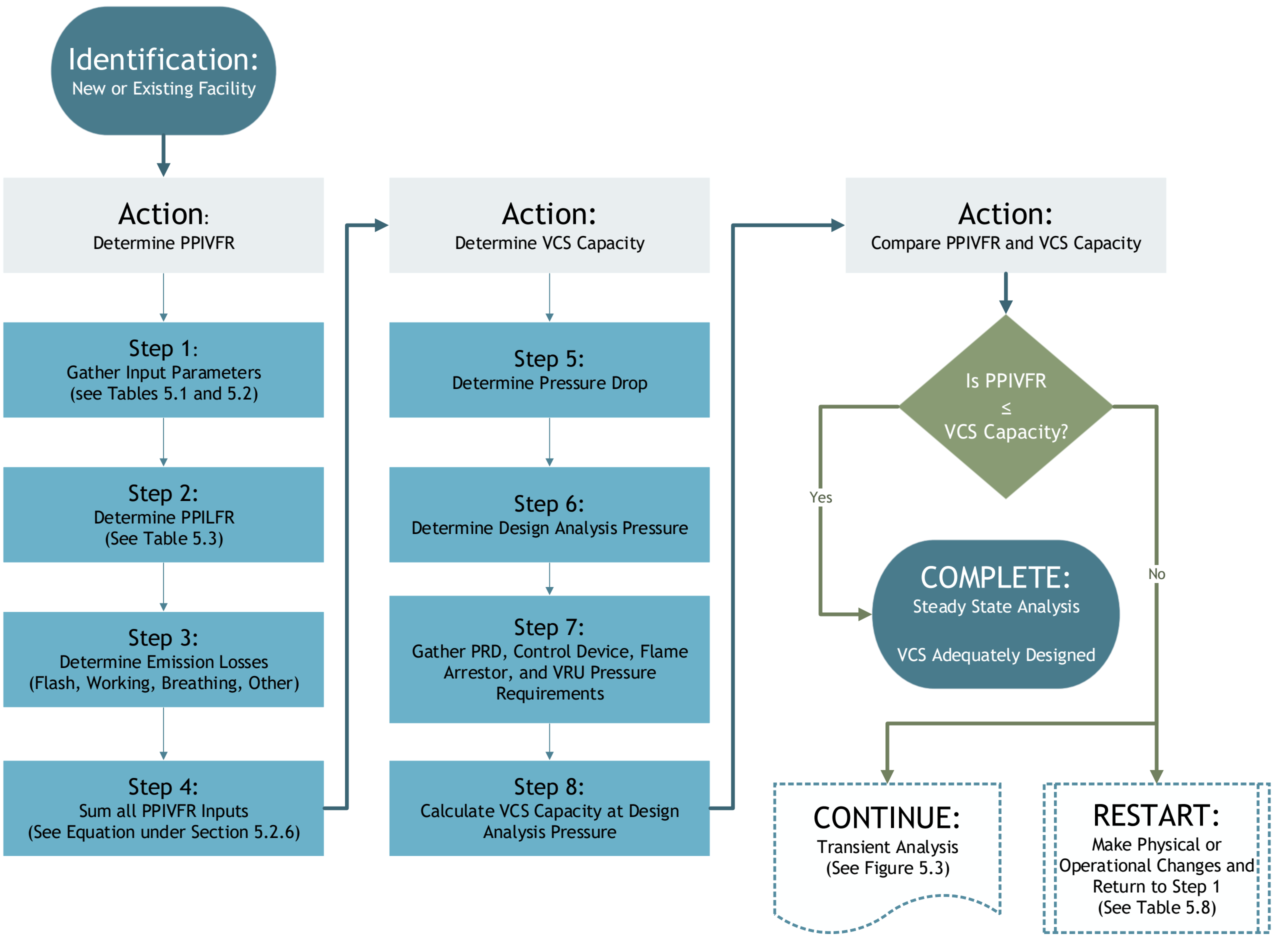
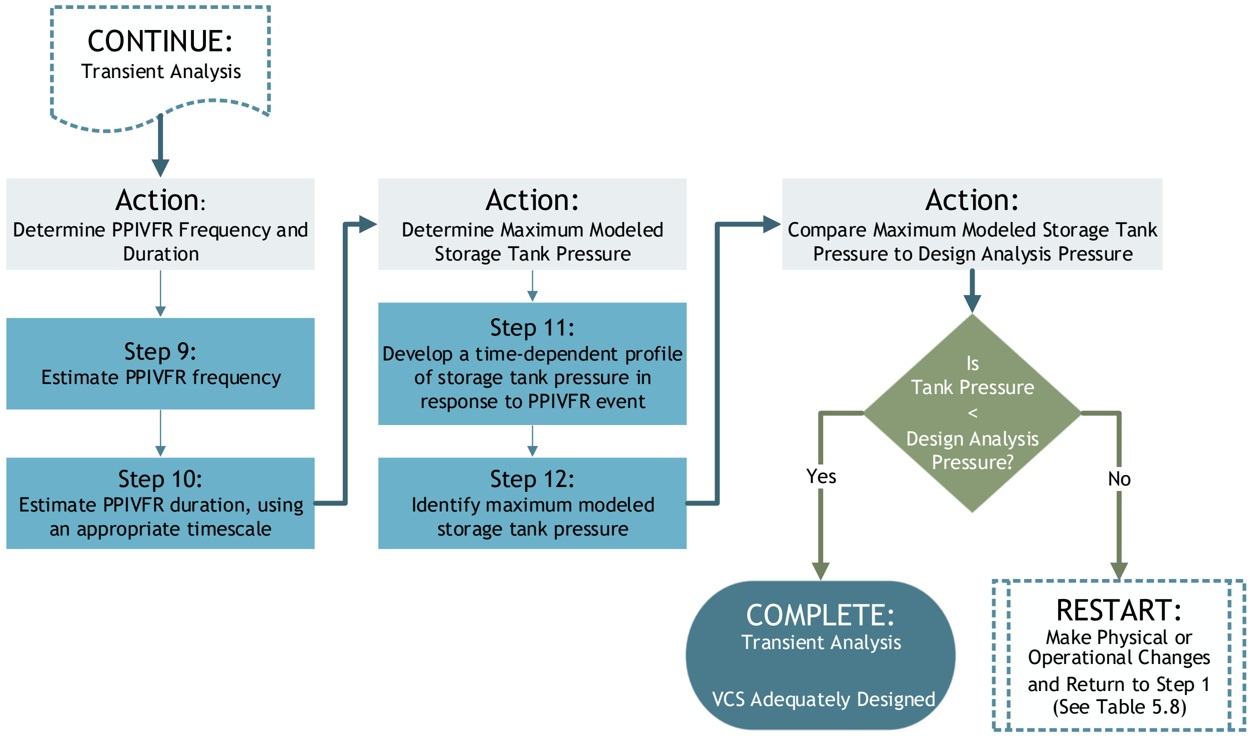


Figure 5.3 Transient Analysis



5.1.3 Evaluating New Versus Existing Vapor Control Systems

These guidelines may be used to evaluate design for new VCS that have not yet been constructed and existing VCS that are already in operation where the operator wants to assess the adequacy of an existing design. In addition, operators may use these guidelines to reassess the adequacy of an existing VCS design when physical or operational changes occur. The process for evaluating new versus existing VCS is similar; however, there are some notable differences. The table below highlights the major process differences between evaluation of a new VCS versus an existing VCS design.

Table 5.1 New vs. Existing Vapor Control System Analysis

Category	New VCS	Existing VCS
Analysis Type	Usually steady-state analysis is used since production rate can be correlated to a well flowrate, unless the downstream separators have snap-acting dump valves in which case transient analysis should be used.	Usually transient analysis is used if plunger wells are used or snap-acting separator dump valves are used. A steady-state analysis may also be appropriate depending on well behavior and process conditions.

Category	New VCS	Existing VCS
Well Flowrate	Production (in bbl/day) is predicted by the operator for each well based on petroleum engineering practices (outside the scope of these guidelines).	Existing facilities will have a known production rate (bbl/day) and well cycles per day. Well flowrate should be calculated depending on the type of well (*e.g.*, free flow, gas lift, plunger etc).
Well Slug Size	Usually not applicable since flow is typically continuous in the early life of a new well.	Applicable for wells operating on plunger lift, and generally not applicable with other methods of artificial lift.
Separator Pressure and Temperature	Use maximum expected separator pressure or the setting of the separator PRD or high-pressure shut down setting. For minimum temperature, use expected temperature of well fluids.	Use maximum recorded from the past year or maximum expected separator pressure in the foreseeable future. For minimum temperature, use minimum recorded temperature of well fluids in the separator.
Separator FGOR and FGWR (SCF/BBL)	Use well fluid sample from a representative site, and model the system in a process simulator (*e.g.*, HYSYS, ProMax, VMGSim) to develop end-to-end system process diagram. Or use flash liberation analysis from a representative sample. Or use correlations.	Use flash liberation analysis or analysis of pressurized liquid sample from the site being evaluated, or a representative site, modeled through a process simulator. Or use appropriate correlations.
Separator Dump Volume	Usually not applicable for steady-state analysis. For transient analysis (snap-acting dump valves in system), dump volume is calculated from specified liquid level controller (selected during design process) and cross-sectional area of selected separator oil/water box.	Calculated from known displacement of float switch, or visually examining sight glass level change during a dump and known cross section of the as-built separator oil/water box. Or, if as-built separator cross sectional area is unknown (*e.g.*, for an old separator where drawings are not available), perform field testing to back calculate separator dump volume.
Separator Dump Frequency	Usually not applicable, as new facilities are typically designed based on a steady-state analysis. However, if snap-acting dump valves exist or any slug flow behavior is anticipated, a transient analysis may be used and separator dump	Calculated from well flowrate, the separator dump volume, and the separator dump flowrate.

Category		New VCS	Existing VCS
		frequency should be estimated. The frequency is calculated from predicted production rates, the separator dump volume, and the separator dump flowrate.	
Vapor Control System Capacity	Storage Tank Capacity and Headspace	The number and size of storage tanks (and available headspace, if using a transient analysis). In a new facility, the VCS design may impact the number of storage tanks installed to provide adequate buffering in a transient analysis.	The number and size of storage tanks (and available headspace, if using a transient analysis).
	VCS Fittings and Components and Pipe Length	The quantity of elbows, bends, tees, and fittings and length of pipe is usually assumed in order to begin the procurement process (ahead of 3D modeling). Or the count of fittings from a similar facility is used. Use conservative number of fittings and length to initially size control devices, and verify once the 3D model and design is complete.	From field inspection, count elbows, bends, tees, fittings, etc. Measure pipe lengths and diameters.
	VCS Control Device Capacity	Determine PPIVFR as described in Section 5.1.6. Provide specification/datasheet to control device vendor with expected vapor composition. From the vendor proposal (usually containing heat rates in MMBTU/hr @ inlet pressure), determine capacity.	For commercial off the shelf control devices, determine control device capacity. For custom control devices, acquire the original proposal or datasheet. From the vendor proposal (usually containing heat rates MMBTU/hr @ inlet pressure), determine control device capacity.

5.1.4 Design Input Parameters

Depending on the evaluation methodologies selected by the operator, a combination of the following input parameters may be utilized to conduct the VCS analysis. Where available, site-specific data should be utilized in the application of the methodologies described in these guidelines. In cases where site-specific data are not available or are unknown, conservative assumptions should be employed. Table 5.2 presents a list of potential design input parameters (*e.g.*, variables that may be used in the design evaluation and system performance) and typical units of measure. The exact parameters used in the analysis should be determined by each operator and may include, but not necessarily be limited to, all or some of the parameters listed below. These parameters may be site-specific, calculated, or in some cases, assumed.

Design input parameter values used in the design analysis should be chosen based on reasonably expected operational field conditions that would result in the maximum PPIVFR. At the conclusion of each design analysis the analyst should identify which input parameters most impact the result of the design analysis (*e.g.*, operating pressure of the last separator upstream of the storage tank); these parameters are called the key design input parameters. It is these parameters that may be selected to be monitored during the subsequent operation of the facility (*see* Section 5.4.1 and 6.3.2) as critical operating parameters.

Table 5.2 Potential Design Input Parameters

Category	Potential Design Input Parameter	Units	Notes
General	Local Barometric Pressure	psia	
Well Data	Maximum Well Instantaneous Liquid Flowrate	gallons/minute	
	Well Type and Behavior (Slug Flow or Steady Stream)	--	
	Well Oil Production Rate	barrels/day	
	Cycles per Day	quantity (qty)	(1)
Separator Data	Separator(s)	qty	
	Separator(s) Pressure Range	psig	
	Separator(s) Temperature Range	°F	
	Separator Oil API Gravity	deg API	
	Separator Vapor Pressure	psig	(2)
	Separator Dump Volume	Gallons/event	(1)
	Separator Dump Frequency	events/min, hour, or day	(1)
	Separator Critical Pressure	psig	(3)
	Oil Viscosity	centipoise (cP)	
	Dump Valve Flow Coefficient (Cv)	gallons/minute/psi	
	Dump Valve Pressure Recovery Factor (Cf)	unitless	
	Dump Valve Actuation Duration	seconds	(1)
	Dump Valve Type (modulated/proportional, or on/off)	--	
	Dump Valve Maximum Trim	inches	
	Throughput Nozzle NPS	inches	
	Oil Throughput Pipe NPS	inches	
	Oil Throughput Pipe Length	feet	
	Oil Throughput Pipe Entrance and Exit Heights	feet	
Tank Data	Quantity of Storage Tanks Connected to the VCS	qty	
	Size of Storage Tanks Connected to the VCS	barrels (bbl)	
	Maximum Tank % Full	%	(1)
	Tank Fill Method (top- or bottom-fill)	--	
	Storage Tank Liquid Maximum Temperature	deg F	
	Minimum Pressure Relief Device Set Pressure	ounces/in^2	(4)

Category	Potential Design Input Parameter	Units	Notes
	Initial Tank Pressure (prior to separator dump)	$ounces/in^2$	(5)
	Storage Tank Oil API Gravity	deg API	
	Storage Tank Vapor Molecular Weight	lbm/lbmol or grams/mol	
VCS Tank Header	Tank Vent Header NPS	inches	
	Tank Vent Header Fittings & Type	qty	
	Tank Vent Header Length	feet	
Main Tank Header	Main Vent Header NPS	inches	
	Main Vent Header Fittings & Type	qty	
	Main Vent Header Length	feet	
Control Device and Control Device Header	Control Device Header NPS	inches	
	Control Device or Flare Header Fittings & Type	type & qty	
	Control Device or Flare Header Length	feet	
	Quantity of Control Devices or Flares	qty	
	Control Device or Flare Capacity	thousand standard cubic feet per day (Mscfd) @ inlet pressure and vapor specific gravity	
	Pressure Drop Across the Control Device/Flare Burner	$ounces/in^2$	
	Pressure Drop Across the Flame Arrestor	$ounces/in^2$	

(1) Not applicable to steady-state analyses.
(2) The pressure exerted by a vapor in equilibrium above the liquid in the separator. It can be conservatively assumed that separator vapor pressure is the same as the separator operating pressure.
(3) The pressure for the oil or water in the separator in which the liquid and vapor phases have the same density. It is typically calculated using a process simulator.
(4) A design analysis pressure lower than the manufacturer's device design relief setpoint may be used in the design analysis; refer to Section 5.1.7.4 for additional discussion.
(5) Pressure in the storage tank vapor headspace immediately prior to the next separator dump event.

5.1.5 Determining PPILFR

The PPILFR, which is needed to determine the PPIVFR, can be impacted by a variety of operating conditions including but not limited to:

- Separator operating pressures and temperatures;
- Potential for simultaneous dump events from multiple separators; and
- Process controls, such as dump valves, control valves, restricting orifices, or cross equipment automation.

PPILFR should be calculated based on the maximum liquid flow from the last stage of separation into the storage tank. For new facilities, this maximum liquid flow may occur at first production or several months after first production.

Liquid flow is normally a 2-phase flow, and can occur as slug flow or steady-state flow. It is important to identify the flow type (by considering the well production method, the type of well, and the separator configuration) before selecting an appropriate method for calculation of PPILFR.

The PPILFR can be determined by applying an engineering methodology appropriate for the given operating conditions and equipment configurations. Possible methodologies are included in Table 5.3, though others may also be used.

Table 5.3 PPILFR Calculation Methods

A.	Incompressible Fluids Non-Choked Flow Calculated via Equation 1, ISA-75.01.01-2007 (60534-2-1-Mod) - *Flow Equations for Sizing Control Valves* (Draft 1)
B.	Incompressible Fluids Choked Flow Calculated via Equation 3, ISA-75.01.01-2007 (60534-2-1-Mod) - *Flow Equations for Sizing Control Valves* (Draft 1)
C.	Liquid Flow Through Orifices, Nozzles, and Venturi via Equation 4-5, *CRANE – Technical Paper No. 410*
D.	Control Valve Sizing and Selection via Equation 3-8, *CRANE – Technical Paper No. 410*
E.	Choked Liquid Flow Through Valves via Equation 3-8, *CRANE – Technical Paper No. 410*
F.	A valve manufacturer sizing program. Examples include Kimray Liquid Sizing, Fisher® Specification Manager and NorriSize®
G.	Direct measurement via a calibrated flow meter at maximum normal operating conditions
H.	Engineering calculation based on separator dimensions, high and low liquid level set points in the Separator, Dump Event duration, and additional liquid fed into the Separator during the Dump Event
I.	Calculations based on maximum daily flow rates and an engineering safety factor when utilizing steady-state modeling

The aforementioned calculations, as appropriate, should be performed with valve, orifice, and equipment specifications provided by the manufacturer and representative hydrocarbon liquid properties. Recognized industry methods and good engineering practices should be used to obtain appropriate information when manufacturer or representative liquids information is unavailable.

Care should be taken to ensure that the estimated PPILFR accounts for all potential sources of liquid entering the storage tank including, but not limited to, simultaneous dump events from multiple separators and recycling of off-specification product. Dump events controlled through automation, timers, etc. in a manner that prevents them from occurring simultaneously should be evaluated, as appropriate, based on such operation.

5.1.6 Determining PPIVFR

The total system peak potential instantaneous vapor flowrate (PPIVFR), Q_{SYS}, is determined by the sum of the total flash PPIVFR, total working PPIVFR, total breathing PPIVFR, and other potential vapor sources PPIVFR.

$$Q_{SYS} = Q_{FLASHTOT} + Q_{WORKINGTOT} + Q_{BREATHINGTOT} + Q_{OTHER}$$

Q_{SYS} = PPIVFR
$Q_{FLASHTOT}$ = Total Flash PPIVFR
$Q_{WORKINGTOT}$ = Total Working PPIVFR

$Q_{BREATHINGTOT}$	=	Total Breathing PPIVFR
Q_{OTHER}	=	Other vapor sources PPIVFR

5.1.6.1 Flash Losses ($Q_{FLASHTOT}$)

Estimation of the flash gas component of the PPIVFR ($Q_{FLASHTOT}$) maybe completed many different ways, but the following common approaches are discussed in these guidelines:

- Estimation of PPILFR of crude oil, condensate, or produced water into the storage tank and multiplying it by the estimated FGOR and/or FGWR;
- Using a process simulation;
- Using a correlation calculation; and
- A combination of the above.

Estimation of FGOR and FGWR are necessary to quantify the total volume of flash gas produced during normal operation. The FGOR and FGWR values can be determined through a variety of methods used individually or in combination. Possible methodologies are shared in in Table 5.4, though others may also be appropriate.

Table 5.4 FGOR or FGWR Estimation Methods

A.	Obtaining a site-specific or representative pressurized liquid and/or gas sample(s) and hydrocarbon composition analysis, used to complete a flash simulation by means of process modeling software such as ProMax, Aspen HYSYS, VMGSim, etc. Process simulation is discussed in more detail below. Pressurized liquid samples shall be collected in accordance with GPA Method 2174 and analyzed via GPA Method 2186/2186M or GPA Method 2103/2103M.
B.	Obtaining a representative pressurized liquid sample and using flash liberation analyses procedures in accordance with CDPHE APCD PS Memo 17-01.
C.	Using empirical flashing correlations, such as Valko-McCain, etc., that can be properly applied based on the facility operating conditions and available data such as liquid API gravity, etc. Additional discussion on the use of correlations is provided below.

The pressurized liquid sample used for flash simulation or flash liberation analysis should be collected at the maximum separator pressure anticipated under normal operation conditions, if possible. If the separator operates at a higher pressure than which the pressurized liquid sample was taken, then FGOR and FGWR will likely be underestimated. If the pressurized liquid sample cannot be collected at the maximum separator pressure, then the analyst should consider applying a correction factor to the FGOR and FGWR. Applying a correction factor will introduce uncertainty and potential error to the PPIVFR calculation and thus should be avoided when possible. Any corrections applied when determining FGOR and FGWR should be documented in the design evaluation report.

If an advanced process simulation (*e.g.*, ProMax, Aspen HYSYS, VMGSim) is being used to estimate FGOR or FGWR, a bubble point check of the pressurized hydrocarbon liquid sample and, if necessary, a bubble point correction or re-sampling should be conducted. There is no standard defined method for a bubble point correction, and so this action is at the discretion of the analyst overseeing the design evaluation. Documentation of the bubble point correction method and basis used should be maintained for any bubble point correction made during a design evaluation.

Once PPILFR and FGOR or FGWR is known, the flash component of PPIVFR ($Q_{FLASHTOT}$) can be calculated by multiplying the crude oil, condensate or produced water volume flow rate by the FGOR or FGWR. Calculation of total PPIVFR (Q_{SYS}) must also include working and breathing losses and other sources of vapor to the storage tank as described in more detail below.

(a) Process Simulation and Modeling

There are many widely used process simulators with oil-and-gas capabilities, including, but not limited to, VMGSim, Aspen HYSYS, and ProMax. The input parameters to process simulators are more detailed than the inputs to correlations, and the user will need to collect more data before beginning the software simulation. The accuracy of the process simulation will depend on the accuracy of the input data. Peng-Robinson, Soave-Redlich-Kwong (SRK), and modified versions of these equations-of-state are acceptable calculation packages to run for these simulations. Please note the division limits the types of software simulation packages that may be used for developing emissions inventories. Therefore, while an operator may choose from a broad list of options for the design evaluation, there is a chance the same approach may not be approved for emissions inventories developed for Air Pollutant Emission Notice (APEN) submittals. Please refer to PS Memo 05-01 for the currently approved process simulators for emission inventory submittals.

(b) Correlations

There are many correlations that have been developed to assist in calculating FGOR (*e.g.*, Valko & McCain, Vasquez-Beggs, Rollins, McCain, Creeger, Weldon Gas-Oil Ratio Chart, etc.). Such correlations provide simplified equations that are easy to use and have been validated by laboratory data. To simplify the equations used to calculate flash emissions, each correlation makes unique assumptions based on the data available to the authors of the correlation and the specific set of conditions the correlation was developed to simulate. For example, most correlations only apply to certain stock tank liquid API gravity, temperature or pressure ranges. Because of these simplifications, many correlations can be used to approximate FGOR without obtaining a pressurized liquids analysis.

Correlations can be a convenient way to approximate FGOR, but are generally considered to be less accurate than other methods (i.e., process simulation and modeling or flash liberation analysis) that utilize pressurized liquid samples collected from the specific site operations under evaluation. If a correlation is used in the design evaluation and emissions are observed from the vapor control system, the operator may need to revisit the design analysis and base the FGOR on a more accurate method.

5.1.6.2 Working Losses ($Q_{WORKINGTOT}$)

Working losses from storage tanks are to be included in the determination of the PPIVFR as they are a potential source of vapor volume to the VCS.

Vapors resulting from working losses ($Q_{WORKINGTOT}$) are due to the changing liquid level and available headspace within the storage tank. Working losses from fixed roof storage tanks can be calculated by, but not limited to, the methods in Table 5.5.

Table 5.5 Working Loss Calculation Methodology

A.	TANKS Emissions Estimation Software, Version 4.09D.
B.	API Standard 2000
C.	AP-42, Section 7.1 – Organic Liquid Storage Tanks, 7.1.3.1.2 Working Loss from Fixed Roof Tanks
D.	Displacement calculations in conjunction with production volumes and storage tank pressure

5.1.6.3 Breathing Losses ($Q_{BREATHINGTOT}$)

Breathing losses from storage tanks are to be included in the determination of the PPIVFR as they are a potential source of vapor volume to the VCS.

Vapors resulting from breathing losses ($Q_{BREATHINGTOT}$) are due to the thermal expansion and contraction of gas/vapor in the storage tank headspace during the diurnal heating cycle. Breathing losses from fixed roof storage tanks can be estimated by, but not limited to, the methods in Table 5.6.

Table 5.6 Breathing Loss Calculation Methodology

A.	TANKS Emissions Estimation Software, Version 4.09D.
B.	API Standard 2000, A.3.3 – Thermal Effects adjusting air for gas density
C.	AP-42, Section 7.1 – Organic Liquid Storage Tanks, 7.1.3.1.1 Standing Storage Loss from Fixed Roof Tanks

5.1.6.4 Other Potential Vapor Sources (Q_{OTHER})

All potential vapor sources (Q_{OTHER}) other than flashing, working, and breathing losses that are or may be routed to the VCS should be evaluated, quantified and included in the PPIVFR calculation. Such sources may include, but are not limited to, those in Table 5.7.

Potential vapor sources should be noted and quantified using vendor provided information, equipment specifications, industry accepted engineering calculations, process modeling software, or direct measurement.

Table 5.7 Other Potential Vapor Sources

A.	Control of truck transfer and loading system emissions
B.	Produced water storage tanks routed to the same VCS
C.	Equipment blanket gas
D.	Equipment purge gas
E.	Natural gas-operated pneumatic devices (*e.g.*, pumps, valves, etc.)
F.	Produced gas from separator vessels not routed to a gas gathering line, VRU, or control device independent of the VCS
G.	Overhead vapors from a VRT not routed to a gas gathering line, VRU, or control device independent of the VCS
H.	Recycling of off-specification product
I.	Receipt of pigging liquids into a tank connected to the vapor control system
J.	Pressure relief to the VCS

K.	Compressor scrubber dumps

5.1.7 Determining Vapor Control System Capacity

VCS capacity represents the ability of a VCS to capture and control a certain volume of vapor at a certain operating pressure. In the context of a design analysis, the VCS capacity reflects the ability of the VCS to manage PPIVFR at a pressure that does not exceed the design analysis pressure (*see* Section 5.1.7.4) or relief set point of any PRD in the vapor control system.

The VCS capacity in a steady-state analysis takes into account the design analysis pressure or relief set point of any PRD in the VCS, the inlet pressure requirement of the control device(s) at a given vapor flowrate, and the pressure loss associated with the piping and components used to convey vapors (at the PPIVFR flowrate) from the VCS to the control device. VCS capacity is typically expressed as a volume per unit of time at a specified specific gravity of the vapor (*e.g.*, thousand standard cubic feet per day or MSCFD @ 1.2 SG).

The VCS capacity in a transient analysis takes into account the same parameters as a steady-state analysis, but also includes the buffering capacity of the storage tank vapor headspace. The VCS capacity may be expressed as a volume per unit of time at a specified specific gravity of the vapor similar to the steady-state analysis, or a maximum predicted storage tank pressure from the analysis compared to the design analysis pressure or relief set point of any PRD in the VCS.

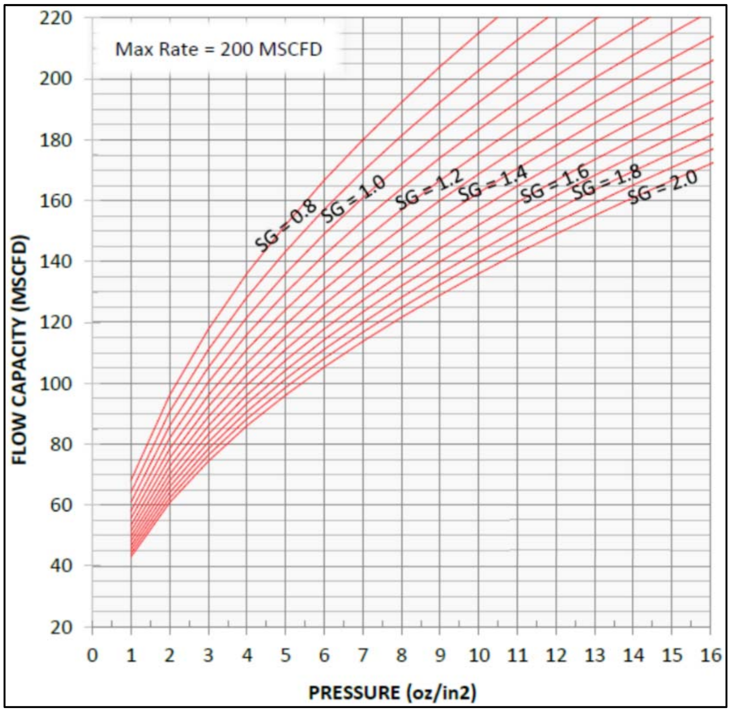
The typical components of a VCS are discussed in more detail below.

5.1.7.1 Control Devices & Flame Arrestors

Each control device will have a unique inlet pressure profile. Manufacturer's literature should be consulted to determine the expected pressure drop associated with the control device, and the device capacity at anticipated operating pressures and vapor density. Most flares and combustors have inline flame arrestors to prevent a fire in an upset condition from propagating back to the storage tank. The pressure drop across the flame arrestors should also be taken into account when sizing the VCS components.

Most manufacturers express the control device capacity in terms of thousand standard cubic feet per day (MSCFD) at a determined specific gravity of the vapors being combusted. When selecting a control device based on the PPIVFR, care should be taken to use consistent units between the manufacturer's control device capacity and the calculated total PPIVFR (Q_{SYS}). An example of a control device capacity curve is below. This curve correlates the volumetric flowrate to both the inlet pressure profile and the specific gravity of the vapors.

Figure 5.4 Example Control Device Capacity Curve



5.1.7.2 Tank Vapor Header Piping

The layout of the tank vapor header piping that runs from the tank vapor outlet(s) to the control device creates pressure loss and resulting backpressure in the storage tank that must be taken into account when sizing the VCS. The vapor line itself creates pressure loss, but other vapor line appurtenances such as valves, fittings, elbows, tees, reducers, inlets and outlets also create pressure loss and must be accounted for in the VCS evaluation. Pressure losses across these components can be estimated by using common engineering references.

The pressure drop through the VCS can be calculated using simulation tools or other pressure drop theories such as the Spitzglass or Darcy-Weisbach equations or other published and industry accepted methods. The chosen method should develop accurate low-pressure hydraulic models. The Spitzglass and Darcy-Weisbach equations can both be solved for the difference in upstream and downstream pressure for a given segment based on the peak volume flow rate.

5.1.7.3 Backpressure Valves

Certain facility configurations may incorporate a backpressure control valve that maintains a small amount of positive pressure on the storage tank. The pressure drop across these valves will vary depending on the model and size, and should be included in the overall pressure profile for the control system. Consult manufacturer literature for equipment-specific information, including pressure drop across the valve at different rates of flow.

5.1.7.4 Liquids Management

Condensed liquids may accumulate in the VCS due to temperature differences within the system. This issue may be prevalent where vapor lines run below ground at a point between the exit of the storage tank and the control device and where the vapor line does not slope back to a liquid knockout vessel or the storage tank. When carried over to the control device, in particular for a combustion device or flare, liquids may cause incomplete combustion, smoking, and a potential safety hazard. Accumulated liquid can also reduce the effective pipe diameter and can thus restrict flow and create backpressure in the VCS. As a result, additional design considerations should be given to prevent liquid buildup in the VCS.

Liquid management options include use of liquid knockout vessels upstream of the control device, manual drains installed on low points in the lines, and sloping vapor lines back toward the storage tank. See Section 6, the O&M guidelines, for best practices along with the design consideration discussion in Section 5.6 for additional information.

5.1.7.5 Pressure Relief Devices

The design analysis must take into account the lowest relief set point of any PRD installed on the VCS. In most cases, the PRDs have a set pressure coinciding with the tank rating (*e.g.*, 8 or 16 oz/in^2) or 2 oz/in^2 lower than the tank rating. Due to the inherent design and operational issues that arise in systems operating at design thresholds less than 16 oz/in^2, PRDs may open at pressures lower than the set point pressure marked on the device or specified by the vendor. The analyst should consider the potential for the PRD to begin emitting vapor at a pressure lower than the published set point of the pressure relief device. API 2000 and API 12F can be used to provide additional guidance regarding initial relief and set point tolerance.

It may be appropriate to utilize this lower pressure as a “design analysis pressure” in the analysis. For example, if the selected PRD has a manufacturer’s rated relief set pressure of 16 oz/in^2, the operator may choose to complete the design analysis to ensure that pressures inside the storage tank do not exceed 12 oz/in^2 (i.e., “design analysis pressure”). In this scenario, the design analysis would be completed such that the design analysis pressure, not the PRD relief set point, is not exceeded in the storage tank. It is the responsibility of the analyst to evaluate the make and model of the PRD in question to determine if this approach is necessary in light of the degree of conservativeness applied elsewhere in the analysis.

5.1.7.6 Vapor Recovery Unit (VRU)

A VRU or multiple VRUs may be installed to capture vapors upstream from the storage tank and compress them for discharge into the gas gathering pipeline. Implementation of a VRU in such a manner will reduce the PPIVFR to be accommodated by the VCS. If a VRU is in use the operator should clarify in the design basis how or if the VRUs are considered in the evaluation and design of the VCS.

5.1.7.7 Storage Tank Headspace

Under a transient analysis approach, the pressure buffering capacity of the storage tank vapor headspace can be considered part of the VCS capacity calculation. This pressure buffering capacity is a function of the volume of vapor headspace, which depends on the liquid level in the tank and the dimensions of the tank. The analyst may base the transient analysis design on an assumed maximum liquid level, which would likely be a "critical operating parameter" subject to periodic monitoring (*see* Section 6.3.2.) Under a steady-state analysis approach, the storage tank headspace is not part of the VCS capacity calculation.

5.1.8 PPIVFR Frequency and Duration Considerations under a Transient Analysis Approach

Estimation of PPIVFR frequency and duration may be necessary when performing a transient type analysis of the VCS (*see* Section 5.1.1 for a description of transient and steady-state analysis methods).

The PPIVFR frequency will vary from site to site – some may be high frequency while others are low frequency. A site where the PPIVFR is much greater than the VCS capacity may be adequately designed if the PPIVFR Duration is short and the frequency is low, such that pressure in the VCS never exceeds the lowest design analysis pressure or relief set point of any PRD in the VCS.

The PPIVFR duration should be calculated considering all potential vapors introduced into the VCS over the appropriate timescale (typically the same timescale as the PPILFR). When determining an appropriate timescale, the analyst should take into account the dump cycle, dump volume, duration, and cycle frequency of the liquid entering and exiting the final stage of separation upstream of the storage tank. It is at the discretion of the analyst to determine the maximum possible flow rate of liquid and appropriate timescale for the PPILFR and PPIVFR.

Under a transient analysis approach, the analyst applies the PPILFR and PPIVFR rate, duration and frequency, as well as all other pertinent VCS parameters (including vapor control system capacity and pressure drop), to calculate a time-dependent profile of tank pressure in response to a PPIVFR event. The maximum modeled tank pressure is then compared to the lowest design analysis pressure or relief set point of any PRD in the VCS.

5.1.9 Determining Design Adequacy

The critical last step in a design analysis is to determine adequacy of the VCS to meet the requirements of Regulation Number 7.

5.1.9.1 Steady-State Analysis Design Adequacy

A design is considered adequate for a steady-state analysis if the PPIVFR is less than or equal to the VCS capacity (with consideration given to pressure drop within the VCS, and to inlet pressure requirements of control device(s)), such that the peak potential tank pressure (under design conditions) does not reach or exceed the lowest design analysis pressure or relief set point of any PRD on the VCS.

Once PPIVFR, the specific gravity of the vapor, and the pressure drop at PPIVFR within the VCS components, piping, fittings and control device(s) is known, design adequacy under a steady-state approach can be demonstrated by two methods:

(a) "Volumetric Comparison" approach, which compares the volumetric VCS capacity at a given maximum pressure (i.e., design analysis pressure minus the pressure drop at PPIVFR from piping and fittings) to the PPIVFR volume rate (taking into account the density of the vapor). If the volumetric VCS capacity is greater than the PPIVFR, steady-state design adequacy is demonstrated; or

(b) "Pressure Comparison" approach, which considers the pressure drop at the PPIVFR within the VCS (including piping, fittings, and control devices) and the inlet pressure requirement of the control device at the PPIVFR, and compares that to the design analysis pressure. If the storage tank pressure at the PPIVFR is less than the design analysis pressure, steady-state design adequacy is demonstrated.

Refer to Section 5.6 for a demonstration of this analysis approach.

5.1.9.2 Transient Analysis Design Adequacy

For a transient analysis, a design is considered adequate if a time-dependent profile of storage tank pressure response to PPIVFR rate, duration and frequency shows that the peak potential tank pressure (under design conditions) does not reach or exceed the lowest design analysis pressure or relief set point of any PRD on the VCS.

5.1.10 Inadequate Design Analysis Options

There are options for operators if either a steady-state or transient analysis shows that a VCS is not adequately designed.

5.1.10.1 Steady-State Analysis – Inadequate Design Options

A steady-state analysis is the more conservative approach, and if a steady-state analysis "fails", (i.e., shows that the system cannot continuously handle PPIVFR), it does not necessarily mean the system is inadequately designed. In such cases, the analyst may:

(a) make equipment and/or operating changes to the system to enable a passing steady-state analysis (*see* Section 5.1.10.3), or

(b) choose to redevelop the model under a transient approach which takes into account the pressure buffering capacity within the storage tank vapor headspace.

5.1.10.2 Transient Analysis – Inadequate Design Options

After a transient design evaluation "fails", the operator may determine a VCS is not adequately designed to meet the requirements of Regulation Number 7. In this case, the operator should implement physical or operational changes such that a revised design analysis incorporating these changes demonstrates the facility is adequately designed (*see* Section 5.1.10.3). If physical or operational changes made by the operator involve critical operating parameters, the operator should identify such parameters and assess the frequency of monitoring and verification in accordance with the O&M guidelines, Section 6.3.2.

5.1.10.3 Initial Physical or Operational Change

If either a steady-state or transient analysis shows that the VCS is inadequately designed, as discussed in Section 5.1.9, then physical or operational changes should be evaluated and implemented to either reduce PPIVFR or increase VCS capacity. Examples are found in Table 5.8, below.

Table 5.8 Common Physical or Operational Changes to Attain Design Adequacy

A.	Decrease well flowrate
B.	Decrease well slug size per plunger arrival
C.	Decrease separator pressure (Hi-Lo limiters)
D.	Decrease separator dump trim size
E.	Add buffer bottles, accumulation bottles, or VRT
F.	Add wellhead, separator, VRT, or tank battery vapor recovery systems
G.	Increase VCS capacity (*e.g.*, additional combustors or increasing line size/components)
H.	Manage storage tank levels to not exceed a certain percent full
I.	Add or remove a storage tank

5.2 Changes and Need for Re-Evaluation

Analysis of the PPIVFR and VCS capacity may need to be verified because of changes to operations or equipment at a source. The source's operations should be reviewed for a potential increase to PPIVFR or decrease to VCS capacity. If PPIVFR increases or the capacity of the VCS to accommodate the existing PPIVFR is reduced, a new engineering design analysis should be conducted. Examples of changes that may affect the analysis are included in Table 5.9, though other changes may also affect the design.

Table 5.9 Common Physical or Operational Changes Which Affect Design

A.	Increases in dump valve size, trim or number
B.	Reduction in capacity and/or removal of a storage tank or control device
C.	Reduction in capacity and/or removal of a VRU
D.	Changes to operating conditions which impact the FGOR/FGWR (i.e., changes to operating temperatures and pressures, reductions to the number of stages of separation, etc.)
E.	Commingling additional well(s)'s production into existing separator or VRT, only if those additional wells can run simultaneously
F.	Changes to controls preventing simultaneous dump events
G.	Changes to artificial lift systems or technology
H.	Drilling of new wells, refracturing or stimulation (i.e., workover) of existing wells producing into the VCS

5.3 Best Practices and Design Suggestions

5.3.1 Best Practices and Design Suggestions for VCS

Operators should consider the following best practices and considerations when designing and constructing a VCS, as applicable and practicable:

- Avoid installation of low points in the system that are not a liquid knockout vessel, whenever possible. Low points in vapor lines are likely to cause fluid accumulation, impede vapor flow, and cause backpressure on the storage tank.
- Slope the tank vapor piping down from the storage tank to a liquid knockout vessel and/or drain, and up from the liquid collection point to the control device.
- Install adequate piping supports to prevent creation of low areas due to sagging vent lines.
- Install liquid knockout drums prior to the inlet of combustion devices to minimize condensed liquids from entering the combustion zone of the combustion device.
- Manage liquid accumulation in knockout vessels (*see* Section 6 for the O&M Guidelines)
- Avoid excessive fittings and construct the vapor line in as straight a line as possible between the storage tank and the control device.
- Select appropriate materials, particularly for parts subject to wear-and-tear such as thief hatch gaskets and seals.
- Install large vapor collection lines to provide higher flow capacity to the emissions control device, and to minimize backpressure on the storage tank.
- Consider use of both a high and low pressure inlet burner ring to effectively manage the anticipated pressure ranges of the VCS.
- Conduct an IR camera inspection or other means of inspection during normal operations, including while and immediately after crude oil or condensate is being sent to the storage tanks to verify the efficacy of the design analysis. In systems where a separator with a dump valve is the last point before liquids flow to a storage tank, the operator should take care to try to observe the storage tanks during a dump event.

5.3.2 Best Practices and Design Suggestions for Production Equipment

Operators should consider the following best practices and considerations when designing and constructing production equipment as applicable and practicable:

- Design separators and other equipment to prevent gas entrainment (vortexing) into the fluid stream entering the storage tank. This may be accomplished by installing a vortex eliminator or equivalent technology, or by maintaining the separator liquid level height to a height greater than the “critical liquid height”, which will be provided by the vendor or calculated.
- When multiple separators are operating simultaneously and dumping directly into a storage tank with a common VCS, consider process controls to ensure timing of dump cycles from individual separators do not overlap.

- Install a sufficient number of separator pressure vessels (i.e., multi-stage separation) between the wellhead and the storage tank to reduce the liquid pressure substantially prior to dumping liquids into the storage tank.
- Work with natural gas gathering contract providers to operate at low sales line pressures to minimize the operating pressure of the wellhead separators.
- Use vapor recovery towers, in combination with a VRU or a dedicated control device, to control flow to storage tanks in a more continuous rather than batch process.
- Ensure gasket materials are compatible with the conditions to which they will be exposed.
- Use heat trace, insulation or chemical inhibitors to ensure lines do not freeze during cold temperatures.

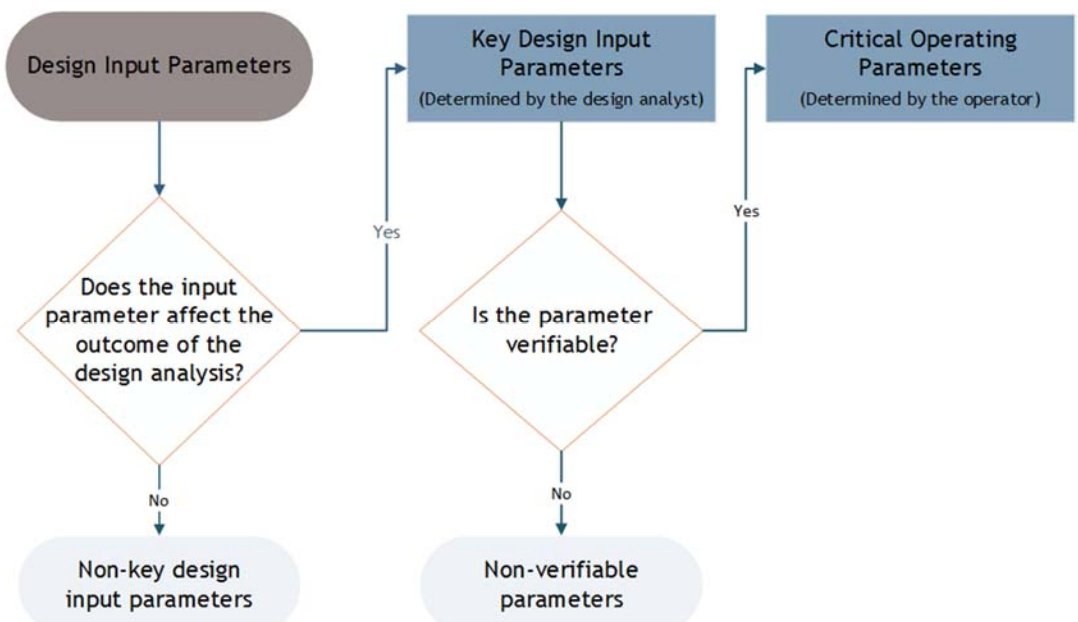
5.4 Operational Considerations

5.4.1 Critical Operating Parameters

After identifying the key design input parameters, a subset of critical operating parameters should be identified and verified to confirm that facilities are constructed and operated in accordance with their design analysis. The parameters that will be verified depend on the design analysis method used and the results of that analysis.

The operator should evaluate each design analysis to determine which design parameters are critical for the purpose of periodic monitoring. See Section 6.3.2 for more information on critical operating parameter verification.

Figure 5.5 Key Input Design Parameters and Critical Operating Parameters



These guidelines contemplate that not all key design input parameters equate to an operational parameter than can be easily observed or verified in the field. For instance the initial pressure in the vapor control system may be a key design parameter than cannot be readily observed or verified in the field. In accordance with Sections 5.5.1 and 6.3.2.2, in the operator's written procedures, the operator should include direction on:

- how an analyst should determine those which are key design input parameters, and
- how the operator should determine those which are critical operating parameters.

5.4.2 Data Uncertainty and Sensitivity Analysis

Uncertainty is inherent in the estimation of PPIVFR and the resultant sizing of VCS components. Sources of uncertainty include collection and analysis of pressurized liquid, the assumptions that must be made to complete the VCS evaluation, correlations and equations used to estimate volumetric flow rates and pressure drops, and other data elements. The analyst may apply a discretionary engineering safety factor, as appropriate, to individual data inputs, the resulting PPIVFR, or specific equipment sizing in order to mitigate potential bias and ensure the resulting design analysis is representative of the range of normal operations.

Calculation methodologies to evaluate and size storage tank components typically use conservative values for the design input parameters. These parameters are applied concurrently; therefore, the calculation is considered to represent a worst-case event. However, the resulting scenario may not represent day-to-day normal operation and, in reality may not occur during the life of the facility.

Operators should include direction in the written procedures to clarify how a design analyst should account for conservative estimations and data uncertainty in the modeling. Additionally, the operator should include general guidelines for the use of safety factors, to balance the risk of a conservative design analysis with oversizing equipment.

5.5 Documentation

Documentation of the design analysis completed should be maintained with the following information. See also Section 3.0 for additional information on documentation.

5.5.1 Design Analysis Written Procedures

In conjunction with the elements described in Section 3.1, the operator should include or address the following in the design analysis written procedures:

- The specific procedures to be followed in designing and sizing VCS;
- Procedures for addressing an initial inadequate design analysis, including short and long-term plans for implementing changes;
- When and how an updated design analysis should be performed;
- How to rectify data uncertainty and account for conservative design input parameters; and
- Description of records to be maintained.

5.5.2 Design Analysis Report

The data sources, assumptions, calculation and statistical methodologies, analytical results, software tools, and any other essential information utilized in the determination of the PPIVFR and sizing of VCS components should be documented in a manner that fosters understanding and transparency for parties reviewing the determinations. Operators should maintain documentation to enable the division to evaluate the assumptions made, the data used, and the calculations performed.

Records should be maintained along with the STEM plan as required by Regulation Number 7, XVII.C.2.b. As described in the Statement of Basis, STEM plans are maintained for the life of the storage tank. Following a design analysis for each facility, the division recommends that operators maintain records of the following information.

5.5.2.1 For all design analysis reports (steady-state and transient):

- The date the design analysis was conducted;
- For PRDs, the “relief set point” pressure and “design analysis pressure” points as described in Section 5.1.7.4, for each make and model of PRD used on the VCS, in ounces per square inch or other appropriate units;
- The calculated PPIVFR, in standard cubic feet per hour at a specified vapor density or other appropriate units;
- The inputs, assumptions, and site-specific operational parameters or practices relied upon in conducting the design analysis for that VCS (*e.g.*, measures to preclude simultaneous dump events, minimum available headspace in tanks);
- The critical operating parameters, resulting from the design analysis, that will be verified;
- The means of inspection or monitoring the operator used to verify the proper performance of the design during normal operations, including while and immediately after crude oil or condensate is being sent to the storage tanks (*e.g.*, IR camera inspection or other means of monitoring), and the date and results of that inspection or monitoring; and
- If a bubble point correction is performed on a pressurized hydrocarbon liquid sample analysis during the design analysis, the correction method and basis.

5.5.2.2 For steady-state design analysis only:

- The VCS capacity, in standard cubic feet per hour at a specified vapor density or other appropriate units; and
- The design pressure at which the VCS capacity was calculated, in ounces per square inch or other appropriate units.

5.5.2.3 For transient design analysis only:

- The VCS capacity, represented by the peak tank pressure as modeled by the design analysis in ounces per square inch or other appropriate units.

5.5.3 Existing VCS with Initial Inadequate Design Analysis

If a design analysis of an existing VCS initially indicates inadequate design, operators should maintain documentation of any physical or operational changes made to achieve adequate design under in accordance with these guidelines. This documentation does not need to be maintained on a facility-specific basis, but operators should be prepared to clearly communicate to the division on the type and frequency of actions taken. For example, operators may maintain a record of how many VCS needed additional control device capacity or well management to prevent simultaneous dumping.

Operators should have instructions and a timeline for implementation of physical or operational changes to resolve design inadequacy. Operators should have a short-term plan to prevent emissions following a design analysis indicating inadequate design until full resolution, and a long term plan to address the timing and procedures for implementation of any necessary changes. This documentation should include timing of completion of changes, and a demonstration that the changes ensure adequate design and subsequent verification re-analysis.

Following an adequate design analysis, the records described above should be maintained for at least two years.

5.6 Steady State Design Analysis Example

Including a Volume Comparison Approach and a Pressure Comparison Approach

There are a minimum of four common steps involved in each analysis. These include:

1. Calculating the PPIVFR; and
2. Determine the specific gravity (SG) of the vapors routed to the VCS; and
3. Determining the lowest pressure (i.e., relief set point or design analysis pressure) at which emissions will result from a pressure relief device; and
4. Calculating the pressure drop at PPIVFR within the piping, fittings and components.

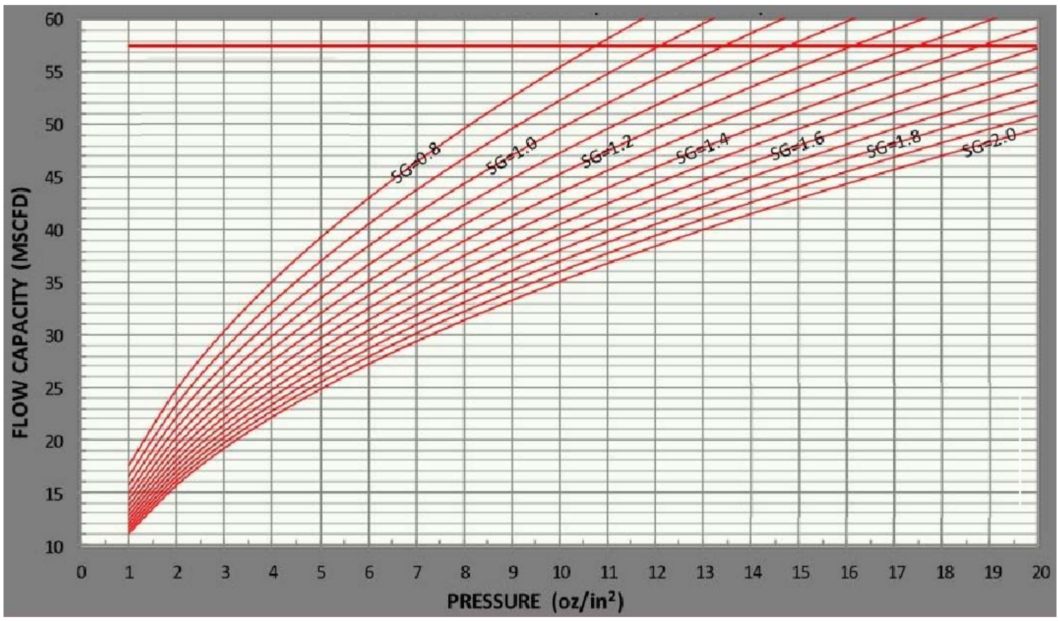
Once this information is determined, the operator may use the emissions control device (ECD) capacity curve and generate either a volume-based PPIVFR to VCS capacity comparison or a pressure-based design analysis pressure to VCS capacity comparison. The differences are illustrated in the example below.

Example

Problem Statement

A site has single separator held at 50 psig that flows continuously to the storage tank at 25 gpm. The storage tank is comprised of two (2) 300 bbl tanks. Tank pressure relief devices have a set pressure of 14 oz/in^2 but based on information provided by the vendor of the relief device, it is assumed that the devices will begin relieving pressure to the atmosphere at 11 oz/in^2. Flash liberation analysis shows flash volume is 40 SCF/BBL with a vapor density of SG =1.0. Using TANKS Emissions Estimation Software Version 4.09D, it is determined that working losses are 10.2 MSCFD @ SG = 1.2, and breathing losses are 14.4 MSCFD @ SG = 0.9. In this simplified example the emissions to the storage tank and vapor control system only consist of flash, working and breathing emissions.

The VCS piping is comprised of 150 ft of 3" NPS pipe, eight (8) 3" NPS 90° elbows, and one (1) 3" Ball Valve. There is one (1) enclosed vapor combustor with the following capacity curves:



Determine whether or not the storage tank relief devices will vent using a Steady State Analysis.

Solution

1. Determine PPIVFR.

   Flash PPIVFR = (40 SCF/BBL) x (1 BBL/42 GAL) x (25 GAL/MIN) x (60 MIN/HR) x (24 HR/DAY) x (1/1000) = **34.29 MSCFD @ SG = 1.0**

   Working PPIVFR = 10.2 MSCFD @ SG = 1.2 (from TANKS 4.09D), which is equivalent to **11.17 MSCFD @ SG = 1.0**

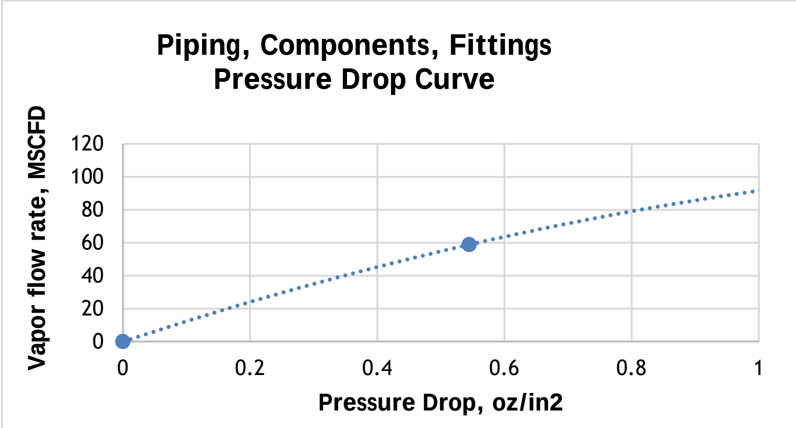
   Breathing PPIVFR = 14.4 MSCFD @ SG = 0.9 (from TANKS 4.09D), which is equivalent to **13.66 MSCFD @ SG = 1.0**

   TOTAL PPIVFR = 59.1 MSCFD @ SG = 1.0

2. Determine the lowest pressure point at which emissions will relieve from the storage tank. In this case, as described above the design analysis pressure is **11 oz/in^2**.

3. Generate the VCS piping, components, and fitting pressure drop curve based on size, length, and number of components and fittings, and determine the pressure drop at

the established PPIVFR flowrate.



In this case, the pressure drop at PPIVFR (59.1 MSCFD) is **0.54 oz/in^2**.

4. In the final step the analyst can read the emissions control device (ECD) capacity curve in one of two ways: either to generate a volumetric-based adequacy determination, or to generate a pressure-based adequacy determination. Both of these approaches are based on the same ECD capacity curve.

   a. Volumetric Comparison Approach
   It was determined in Step 2 that emissions will occur at 11 oz/in^2 pressure. Next, determine the inlet pressure to the ECD at that maximum storage tank pressure by taking into account the VCS backpressure at PPIVFR, which was calculated in Step 3 as 0.54 oz/in^2.

   $$11 \text{ oz/in}^2 - 0.54 \text{ oz/in}^2 = \mathbf{10.46 \text{ oz/in}^2}$$

   Use the ECD capacity curve to determine the flowrate that the ECD is able to achieve at the maximum ECD inlet pressure. In this case, the ECD flowrate at 10.46 oz/in^2 is approximately **51 MSCFD at SG = 1.0**.

   Conclusion: In this case 59.1 MSCFD @ SG = 1.0 (PPIVFR) > 51 MSCFD @ SG = 1.0 (VCS Capacity) therefore the design is not adequate according to a steady-state analysis.

   b. Pressure Comparison Approach
   It was determined in Step 2 that emissions will occur at 11 oz/in^2 pressure. Use the calculated PPIVFR (from Step 1: 59.1 MSCFD @ SG = 1.0) with the ECD capacity curve to determine the inlet pressure at which the ECD has to operate to handle the PPIVFR flowrate. Use the PPIVFR volume on the Y-axis of the ECD capacity curve to read the inlet pressure on the X-axis.

In this case, the ECD inlet pressure would need to be approximately **14.2 oz/in²** to achieve the PPIVFR flowrate of 59.1 MSCFD at SG 1.0. Add the backpressure at PPIVFR to the ECD inlet pressure to arrive at the total pressure within the storage tank at PPIVFR.

$$14.2\ \text{oz/in}^2 + 0.54\ \text{oz/in}^2 = \mathbf{14.74\ oz/in^2}$$

Conclusion: In this case 14.74 oz/in² (storage tank pressure @ PPIVFR) > 11 oz/in² (design analysis pressure), therefore the design is not adequate according to a steady-state analysis.

5. After these inadequacy determinations, the design can be revised to either reduce PPIVFR or increase VCS capacity (or the analyst may redevelop the model under the transient analysis method).

   For this example, let's revise the site design to include an additional stage of separation before the storage tanks, which reduces the flash PPIVFR to 15.17 MSCFD @ SG = 1.0. Working and breathing emissions are not changed, so total PPIVFR is now 40 MSCFD @ SG = 1.0.

   Using the same pressure drop curve developed for Step 3, at 40 MSCFD the piping/components/fittings pressure drop is 0.33 oz/in².

   Using the process of Step 4.a, the inlet pressure to the ECD at the design analysis pressure whileconsidering the VCS piping backpressure is 11 oz/in² – 0.33 oz/in² = **10.67 oz/in²**.

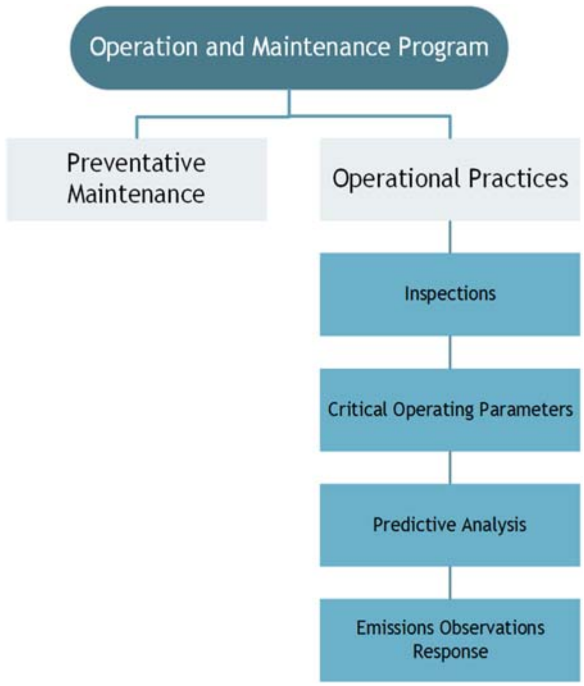
   Using the ECD capacity curve, at 10.67 oz/in² the ECD can handle 51.5 MSCFD @ SG = 1.0. This VCS capacity (51.5 MSCFD @ SG = 1.0) is greater than the PPIVFR (40 MSCFD @ SG = 1.0), so design adequacy is demonstrated under the revised design using the Volumetric Comparison approach.

6.0 Operation and Maintenance Guidelines

The O&M guidelines contain two primary components: preventative maintenance and operational programs.

6.1 Operation and Maintenance Flowchart

Figure 6.1 Operation and Maintenance Program



6.2 Preventative Maintenance Program

Operators are responsible for developing their individual preventative maintenance (PM) programs, including the development of written procedures that identify maintenance practices and specify schedules. This section is intended to provide a framework of expected content for operators' PM programs, in addition to specific requirements of Regulation Number 7.

6.2.1 PM Written Procedures

The PM written procedures should:

(a) Specify the procedure for each PM.

For each PM activity, the written procedures should include sufficient detail to describe the "procedure" or process by which the event will be performed. The written procedures may be based on manufacturer specifications and/or company-specific protocols, and they should identify the conditions under which equipment should be replaced or repaired prior to failure (*e.g.*, where PM inspection identifies significant wear and tear on a gasket, when the gasket should be replaced even if no emissions have yet been observed from the thief hatch).

The division suggests that operators within the non-attainment area take reasonable actions to minimize emissions during PM where practicable. One way operators can do this, as an example, is by minimizing the frequency of depressurization of equipment, tanks or other surface equipment and performing multiple O&M activities during the same depressurization event, reducing the need to vent by getting work done efficiently.

(b) Designate the frequency for each PM.

The recommended frequency for PM activities is in Section 6.2.2. If an operator determines that a particular piece of equipment requires PM more frequently than recommended by these guidelines, the facility PM frequency should reflect the appropriate schedule.

If a PM at a lesser frequency than recommended by Section 6.2.2 is used, the operator should document its justification for the reduced frequency. Documentation should include sufficient evidence to support the change (*e.g.*, historical records of facility operation, records of maintenance activities, etc.).

In recognition of the community effort to reduce emissions during the peak summer ozone season in the nonattainment area, the division asks that operators in the nonattainment area not perform PM activities that will result in emissions during the months of May through September, where possible and where such activities will not cause safety concerns.

The division also encourages operators in the nonattainment area to participate in its ozone alert/voluntary reduction measures program to reduce PM activity related emissions on days when high ozone is more likely to occur.

(c) Document which PM procedures and frequencies are applicable to each facility.

The Statement of Basis to Regulation Number 7 provides that operators should be able to identify what STEM Plans apply to each storage tank. Likewise, the division expects operators to be able to identify which procedures apply to each VCS.

(d) Define PM recordkeeping.

Written procedures should sufficiently describe what and how records will be maintained. PM recordkeeping is primarily intended to provide information for operators to understand facility and field-wide operations, through the predictive analysis program in Section 6.3.3.

Where a written procedure prescribes a frequency for a specific PM activity and its follow-up maintenance actions, a record of the date that the PM occurred is sufficient recordkeeping of the PM event. Follow-up maintenance actions taken outside of a specific schedule as outlined in the operator's O&M written procedures should be identified explicitly in records, which are described more fully below.

For example, if an operator's written procedures require the replacement of equipment on a specified schedule (*e.g.*, every six months), the operator should maintain a record of the date of the PM event (which, in conjunction with the written procedures, would serve as documentation that the event did, in fact, occur). In contrast, if an operator's written procedures require the replacement of equipment “as needed”, the operator should maintain a record of the date of the PM event, the follow-up maintenance action taken (i.e., the replacement of the equipment), and the date the action was taken.

Examples of records that could be maintained for PM activities are included in Section 6.2.2 and 6.2.3.

(e) Outline the method to ensure spare parts are available.

The operator should document how it will maintain access to commercially available spare parts to support routine operating and maintenance activities. This method should include how an operator will evaluate whether unavailable parts repeatedly cause delay in the performance of PM activities or in the ability to respond to emissions observations. If an unavailable part repeatedly causes delay, the access to spare parts will be re-evaluated, and reasonable attempts will be made to improve access to that part.

(f) Be updated to reflect revised PM procedures and frequencies, as appropriate.

6.2.2 PM Activities and Frequencies

As well as any other activities and recordkeeping required by Regulation Number 7, the division recommends that a PM program include the following activities and recommended recordkeeping (subject to and limited by the records discussed in Section 6.2.1(d)) on the following frequencies:

(a) During, or on the same frequency as, AVO Inspections (conducted pursuant to Regulation Number 7, Sections XII.E.3.e and XVII.C.1.d, as applicable):

(a)(1) Visually observe the dump valve(s) of the last separator(s) before storage tanks to ensure it/they is/are not stuck open and is/are free of debris. An operator is not required to observe the actuation of the dump valve during this inspection; however, if a dump event occurs during the inspection, confirm proper operation of the valve.

Record the following: (i) date of PM; (ii) if any action was taken in response to observation of improper position of valve or debris, record the action taken (including the date).

(a)(2) Visually observe thief hatches and hatch-style pressure relief devices to ensure they are closed, seated and latched and free of debris.

Record the following: (i) date of PM; (ii) if any action was taken in response to observation of open, unlatched, or improperly seated device, record the action taken (including the date).

(a)(3) Visually observe pressure relief devices (PRDs) other than (a)(2) above to ensure they are closed and seated properly and free of debris.

Record the following: (i) date of PM; (ii) if any action was taken in response to observation of open, improperly seated, or clogged PRD, record the action taken (including the date).

NOTE: The division does not expect operators to climb on top of a tank, but operators are expected to use an available catwalk or similar permanent access to ensure the best opportunity for inspection, except when a catwalk is not accessible due to a safety hazard.

(a)(4) Liquid knockout vessels

(a)(4)(i) For liquid knockout vessels for which a procedure exists to check liquid level, check for the presence of liquids. If liquids are present above the low level indication point, drain liquids unless the knockout is drained automatically. Record date of PM.

(a)(4)(ii) For liquid knockout vessels for which no procedure exists to check liquid level, drain liquids. Record date of PM.

(a)(5) For underground lines and aboveground piping that is not sloped to a liquid knockout or tank, and for which a procedure exists to check for the presence of liquids accumulation, check for the presence of liquids. Drain liquids as needed (as described in written procedures). Record (i) date of PM; and (ii) whether liquids were removed.

(b) Quarterly:

For underground lines and aboveground piping that is not sloped to a liquid knockout or tank, and for which no written procedure exists to check for the presence of liquids accumulation, drain liquids. Record date of PM.

(c) Semi-annually:

(c)(1) Disassemble and visually inspect thief hatches and hatch-style pressure relief device gaskets, seals, and sealing surfaces for proper condition and integrity, and visually inspect spring condition and rating (if markings are visible). Clean thief hatch parts and surfaces. Replace seals, springs and other parts as needed.

Record the following: (i) date of PM; (ii) if gaskets or other parts were replaced, record the action taken (including the date).

NOTE: If technology is employed to avoid the need to open the thief hatch during gauging and unloading (such as auto-gauging and/or LACT units), this inspection can be conducted annually.

(c)(2) At facilities where emissions are controlled during liquid loadouts, inspect the vapor return line and connectors for corrosion, emissions, and staining or other evidence of liquids along piping. Repair or replace lines or connectors as needed.

Record the following: (i) date of PM; (ii) if lines or connectors were repaired or replaced, record the action taken (including the date).

(d) Annually:

(d)(1) Observe separator dump valve actuation for proper operation. Repair or replace as needed. Record the following: (i) date of PM; (ii) if parts are repaired or replaced, record the action taken (including the date).

(d)(2) Visually inspect the exterior of tanks for corrosion and excessive staining that is not due to tank gauging, sampling, or maintenance. Clean, repair, or replace as needed. Record the following: (i) date of PM; (ii) if tanks are cleaned, repaired, or replaced, record the action taken (including the date).

(d)(3) Visually inspect the exterior of exposed vapor control system piping and liquid knockout vessels for corrosion. Repair or replace parts as needed. Record the following: (i) date of PM; (ii) if parts are repaired or replaced, record the action taken (including the date).

(d)(4) Visually inspect PRD internals and seals for integrity, clean parts and surfaces. If feasible, disassemble the PRD to perform this inspection. If the PRD is unsafe or difficult to access, perform an AIMM inspection of the device. Repair or replace seals or other parts as needed. Record the following: (i) date of PM; (ii) if parts are repaired or replaced, or emissions are observed during the AIMM inspection, record the action taken (including the date). If an AIMM inspection is performed in lieu of a physical inspection, the division recommends retention of the video when emissions are observed until at least the next predictive analysis.

(d)(5) Visually inspect and clean flame arrestor element assemblies and gasket seals. Replace seals or other parts as needed. Record the following: (i) date of PM; (ii) if parts are repaired or replaced, record the action taken (including the date).

(d)(6) Visually inspect and clean combustion device burners/tips, air intakes, and flare waste gas motor valves, if applicable. Repair or replace parts as needed. Record the following: (i) date of PM; (ii) if parts are repaired or replaced, record the action taken (including the date).

(e) Other Schedule:

(e)(1) If a combustion device is observed to be smoking, check lines for liquids accumulation and clear them as needed. If a check for liquids is not practicable and another cause was not identified and corrected, clear liquids from the lines. Repair or replace parts as needed. Record the following: (i) date of PM; (ii) if lines were cleared of liquids or combustion device parts were repaired or replaced, record the action taken (including the date).

Note: This does not negate the requirements to perform a Method 22 or follow the Procedures on Visible Emissions published on August 22, 2014.

(e)(2) Conduct Vapor Recovery Unit (VRU) PM including checking the filters, belts and oil changes, as applicable, in accordance with manufacturer specifications or company developed PM practices and schedules. The PM written procedure should outline or attach the manufacturer specifications or company practices. Where a company deviates from the manufacturer specifications, the operator should document in the PM written procedure: the revised PM schedule and the rationale for the change. Maintain records of any follow-up maintenance actions (including date and description) not explicitly outlined in the PM procedures, as discussed in Section 6.2.1(d).

6.3 Operational Practices Program

6.3.1 Inspections

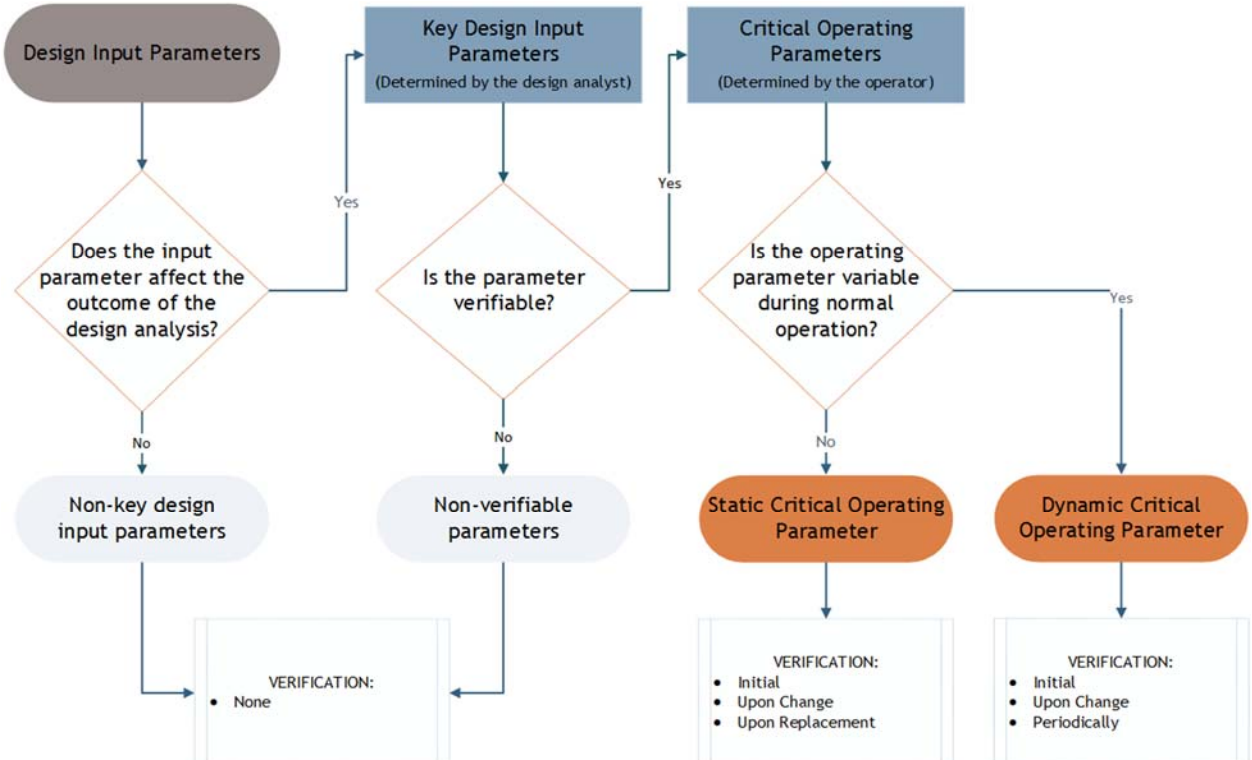
Operators should develop a written procedure for inspections conducted to comply with Regulation Number 7, including audio-visual-olfactory (AVO) and Approved Instrument Monitoring Method (AIMM) inspections. The written procedure should identify the schedule and minimum requirements for conducting inspections required by Regulation Number 7. The written procedures should also include instructions for investigating and addressing observations of emissions and how to apply corrective action appropriately to the determined cause. Operators should maintain the records required by Regulation Number 7 and otherwise recommended by these guidelines, including the date of any inspections and records of emission response actions.

6.3.2 Critical Operating Parameter Verification

Critical operating parameters should be identified and verified by the operator to confirm that facilities are constructed and operated in accordance with their design analysis. The parameters that will be verified can depend on the design analysis method used and the results of that analysis. The operator should evaluate the design analysis for each VCS to determine which key design input parameters are critical for the purpose of periodic monitoring.

These guidelines recognize that some critical operating parameters are static and others are dynamic. Static parameters are those that cannot readily change (*e.g.*, the diameter of a vapor flowline pipe). Dynamic parameters are those that maintain the ability to vary during field operations (*e.g.*, separator operating pressure).

Figure 6.2 Critical Operating Parameter Verification



Typically, static critical operating parameters should be monitored after initial commencement of operation and upon a change, as discussed in Section 5.2. In some cases, static parameters should also be monitored or reverified upon replacement of the affected part.

Dynamic critical operating parameters may warrant monitoring upon commencement of operation and then on a periodic basis thereafter due to their ability to vary. If a design analysis used the maximum or most conservative value within the operational range of a dynamic critical operating parameter, it may warrant less frequent periodic monitoring or even initially and only upon change or replacement as for a static critical operating parameter. If a dynamic critical operating parameter is known to vary frequently during field operations and to substantially influence the VCS performance or PPIVFR, it likely warrants more frequent periodic monitoring.

6.3.2.1 Parameter monitoring and frequency

The following tables identify some recommended parameters and frequency of observation. For a particular VCS, the operator may determine that some parameters in the tables below need not be monitored. However, the operator should consider and may select additional parameters that should be monitored, based on the design analysis. The operator should evaluate whether monitoring and verification should occur more or less frequently than recommended in the tables below.

Table 6.1 Steady-State Design Analysis: Potential Critical Operating Parameters

Potential Critical Operating Parameter	Method of Verification	Suggested Observation Frequency(1)
Liquid/vapor inputs to storage tank and VCS	Verify sources of inputs and associated volumes and flowrates (*e.g.*, separators, VRTs, LACT reject, loadout vapor balance, etc.)	Initial and upon change
Separator dump valve type (mech, throttle, or snap), size and trim	Visual observation of dump valve configuration	Initial and upon change
Storage tank capacity	Visual observation of number and size of tanks	Initial and upon change
Equivalent length of VCS components	Measurement of vapor line diameter	Initial and upon change
	Measurement of vapor line length	Initial and upon change
	Visual observation of number and size of VCS fittings (*e.g.*, elbows, valves)	Initial and upon change
Control device capacity at anticipated inlet pressure	Visual observation of control devices (number, make, model) and verification of flow capacity at anticipated inlet pressure from manufacturer specifications	Initial and upon change
Well Type (free flow, gas lift, plunger, etc)	Verify well type and method of operation	Initial and upon change
Lowest PRD set point or verification that lowest PRD set point is above design analysis pressure	Visual observation of thief hatch spring pressure rating	Initial and upon change or replacement
	Confirmation of PRV pressure relief set point	Initial and upon change or replacement
Maximum pressure of the last separator before storage tanks	Observation of analog pressure gauge or use of a pressure transducer	Monthly

(1) See Section 5.2 for examples of what activities constitute a change and warrant remonitoring.

Table 6.2 Transient Design Analysis: Potential Critical Operating Parameters

Potential Critical Parameter	Method of Verification	Suggested Observation Frequency(1)
Liquid/vapor inputs to VCS	Verify sources of inputs and associated volumes and flowrates (*e.g.*, separators, VRTs, LACT reject, loadout vapor balance, etc.)	Initial and upon change
Separator dump valve type (mech, throttle, or snap), size and trim	Visual observation of dump valve configuration	Initial and upon change
Number and size of tanks	Visual observation of number and size of tanks	Initial and upon change
Equivalent length of VCS components	Measurement of vapor line diameter	Initial and upon change
	Measurement of vapor line length	Initial and upon change

Potential Critical Parameter	Method of Verification	Suggested Observation Frequency(1)
	Visual observation of number and size of VCS fittings (*e.g.*, elbows, valves)	Initial and upon change
Control device capacity at anticipated inlet pressure	Visual observation of control devices (number, make, model) and verification of flow capacity at anticipated inlet pressure from manufacturer specifications	Initial and upon change
Lowest PRD set point or verification that lowest PRD set point is above design analysis pressure	Visual observation of thief hatch spring pressure rating	Initial and upon change or replacement
	Confirmation of PRV pressure relief set point	Initial and upon change or replacement
Tank liquid level	Manual gauging	For tanks that are unloaded at least semi-annually, either record the tank liquid level monthly, or maintain all available tank gauging records. For tanks that are unloaded less frequently than semi-annually, check the level at the time of the semi-annual PM for thief hatches.
	Automated gauging	Continuously at frequency utilized in SCADA system (*e.g.*, hourly).
Well Production per day (bbl/day)	Flow meter or tank gauging	New facilities: Monitor periodically until peak production is reached, and upon change. For existing facilities: Initial and upon change.
Well cycles per day	Review of operational data such as casing and tubing pressure.	Initial and upon decrease in cycles per day
Well Type (free flow, gas lift, plunger, etc)	Verify well type and method of operation	Initial and upon change
Maximum pressure of the last separator before storage tanks	Observation of analog pressure gauge or use of a pressure transducer	Monthly

(1) See Section 5.2 for examples of what activities constitute a change and warrant remonitoring.

6.3.2.2 Critical operating parameter written procedures

In the written procedures, the operators should identify:

(a) The critical parameters affecting operation of a VCS in accordance with the design analysis, or where to find the critical parameters for each VCS (i.e., in the design analysis report).

(b) The value/range for each critical operating parameter that the design analysis identified as critical to maintain.

(c) The method of verification of each critical operating parameter (*e.g.*, if verification is done by onsite personnel, the procedures should describe how information on the critical parameters and design values is made available to onsite personnel; if verification is accomplished through automation or engineering controls, the procedures should describe how automation or engineering controls will be confirmed, etc.).

(d) The frequency for periodic verification.

(e) The triggers for individual facility evaluation in “Schedule 2” of the Predictive Analysis (triggers include, but are not limited to: multiple critical operating parameters outside of design value simultaneously, repeat of single critical operating parameter outside of design value).

(f) The records that should be maintained, including:

(f)(1) Dates of verification, and

(f)(2) Deviations from critical operating parameters (*e.g.*, what was the separator pressure if outside of design value).

6.3.3 Predictive Analysis

A predictive analysis is an important operational program, utilizing actual data to identify and prevent emissions at a particular facility and across all facilities in an operator’s control. Operators should periodically review records to identify if:

- There are recurring issues at an individual facility.
- There are recurring issues with similar equipment across multiple facilities (*e.g.*, make and model of equipment).
- There are recurring issues across different design or operational configurations (*e.g.*, stages of separation, operational parameters, etc.).
- There are recurring issues at an individual facility or across multiple facilities with PM and inspection schedules and activities being performed or recorded as specified (*e.g.*, were inspections conducted in accordance with frequency required by Regulation Number 7?). The Division does not expect operators to verify that it has followed all maintenance, inspection and repair schedules at each facility during each review. Instead, operators have the flexibility to set forth in their written procedures the method by which this verification will be performed.
- There are deviations of critical operating parameters that have exceeded the defined triggers for individual VCS design analysis or that otherwise call into question the validity of the design analysis.

The division recommends that the person performing this predictive analysis review for a particular facility should not be the person who is primarily responsible for performing O&M activities at that facility, unless the operator has no other personnel qualified to perform the predictive analysis. For example, a small operator with limited personnel with expertise in these programs could have the same person perform O&M and the Predictive Analysis.

The operator should determine if recurrent issues are specific to a component, specific to a facility, specific to a design or operational configuration, or systemic, and take response action as necessary.

6.3.3.1 Records to review

This review should evaluate, at a minimum:

(a) Follow-up maintenance action records, in accordance with Section 6.2.1.1(d);

(b) Inspection records;

(c) Records of emission response actions where emissions were observed from the storage tank;

(d) Corrective action records related to control devices; and

(e) Deviations from critical operating parameters.

Each predictive analysis should encompass 12 months of records, or the entirety of operation if in operation for less than 12 months.

6.3.3.2 Review process and schedule

The operator should conduct the review in accordance with one of the following schedules:

Schedule 1: Semi-annually for all facilities (field-wide and individual facility), looking at all records for the previous 12-month period.

~OR~

Schedule 2:

(a) Annually for all facilities (field-wide and individual facility); and

(b) For an individual facility upon the occurrence of any of the following:

(b)(1) Three observations of emissions from a single storage tank in any six month period. (For clarification, emissions from multiple locations on a single storage tank that are observed during a single inspection or site visit count as one observation.);

(b)(2) Multiple deviations of any single critical operating parameter from the design analysis relating to a single vapor control system (as identified in written procedures, and *see* Section 6.3.2.2(e), above); or

(b)(3) A triggering event from the design analysis.

6.3.3.3 Predictive analysis recordkeeping

Operators should maintain records identifying the date(s) on which this predictive analysis is performed, the person(s) who performed the analysis, a description of any facility-specific or field-wide issues identified, the action taken to address such issues (and the dates of such action), and any updates to the written procedures made as a result. The division expects that if an operator identifies a facility-specific or field-wide issue, the operator should, as appropriate, develop both a short-term plan and a long-term plan for implementation. The short-term plan would focus on minimizing any potential emissions that might result until the long-term plan is fully implemented.

The operator's written procedures or STEM plan should describe the method by which the predictive analysis is performed, the records to be included, and the recordkeeping to be maintained.

6.3.4 Vapor Control System Emission Observations Response

(a) Timing

Emission observation response is not limited to emissions observed during Regulation Number 7 inspections, but to emissions observed at any time, including those observed by the division. Emissions observed which are determined to be leaks (and not venting) should be handled in accordance with Regulation Number 7, Sections XII.L or XVII.F, as applicable. Venting should be eliminated.

(b) Remonitoring

For emissions identified, remonitoring should be conducted using AIMM, including soapy water.

(c) Emissions from thief hatch or PRD

If emissions are observed from a thief hatch or PRD, operators should attempt to determine the cause and take appropriate emission response action. If the cause of emissions cannot be determined, the division expects that operators will inspect the thief hatch or PRD internals (gaskets, seals, springs, etc.), and clean, repair, or replace parts as necessary as part of the investigation into the cause of the emissions.

(d) Recordkeeping

Consistently with Regulation Number 7, the operator should maintain records of all emission observations and emission response actions, including identification method, cause, dates of finding and correction, and action taken to eliminate or reduce emissions.

7.0 References

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American Petroleum Institute, *Evaporative Loss Measurement, Section 1 – Evaporative Loss from Fixed-Roof Tanks*, Fourth Edition (October 2012) and earlier editions.

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US Environmental Protection Agency, Office of Enforcement and Compliance Assurance, Compliance Alert – EPA Observes Air Emissions from Controlled Storage Vessels at Onshore Oil and Natural Gas Production Facilities, September 2015.

8.0 Example Recordkeeping

The tables herein provide examples and suggestions for recordkeeping of PM activities, as described in Section 6.2.2, with the intention of clarifying the concepts included in that section. These tables do not represent required formats or forms; instead the operator should create a recordkeeping format in line with written procedures, to complement the software, processes, or procedures applicable to the operator. Nothing in these forms is intended to permit operators to deviate from specific recordkeeping or reporting requirements of Regulation Number 7, including, without limitation, Sections XII.E.3., XII.F., XII.L, XVII.C.3, and XVII.F.

Table 8.1 Example Recordkeeping for PM Activities

Frequency	PM Activity	Date Performed	Follow-up Maintenance Action Needed?	
			Yes(1)	No
AVO Frequency	Observe the dump valve(s) of the last separator(s) before storage tanks for proper operation and that			

Frequency	PM Activity	Date Performed	Follow-up Maintenance Action Needed?	
			Yes(1)	No
	it/they is/are not stuck open and is/are free of debris.			
	Visually observe thief hatches and hatch-style pressure relief devices to ensure they are closed, seated and latched and free of debris.			
	Visually observe pressure relief devices (PRDs) to ensure they are closed and seated properly and free of debris.			
	For liquid knockout vessels for which a procedure exists to check liquid level, check for the presence of liquids. Drain as needed.			
	For liquid knockout vessels for which no procedure exists to check liquid level, drain liquids.		--	--
	For underground lines and aboveground piping that is not sloped to a liquid knockout or tank, and for which a procedure exists to check for the presence of liquids accumulation, check for the presence of liquids. Drain liquids as needed.			
Quarterly	For underground lines and aboveground piping that is not sloped to a liquid knockout or tank, and for which no written procedure exists to check for the presence of liquids accumulation, drain liquids.		--	--
Semi-Annual	Disassemble and visually inspect thief hatches and hatch-style pressure relief device gaskets, seals, and sealing surfaces for integrity, and visually inspect spring condition and rating (if markings are visible). Clean thief hatch parts and surfaces.			
	Inspect the vapor return line and connectors for corrosion, emissions, and staining or other evidence of liquids along piping.			
Annual	Observe separator dump valve actuation for proper operation.			
	Visually inspect the exterior of tanks for corrosion			

Frequency	PM Activity	Date Performed	Follow-up Maintenance Action Needed?	
			Yes[1]	No
	and excessive staining that are not due to tank gauging, sampling, or maintenance.			
	Visually inspect the exterior of exposed vapor control system piping and liquid knockout vessels for corrosion.			
	Visually inspect PRD internals and seals for integrity, clean parts and surfaces. If feasible, disassemble the PRD to perform this inspection.			
	Visually inspect and clean flame arrestor element assemblies and gasket seals.			
	Visually inspect and clean combustion device burners/tips, air intakes, and flare waste gas motor valves, if applicable.			

Table 8.2 Example Recordkeeping for Follow-up Maintenance Actions

Date of PM activity	Issue observed	Follow-up maintenance action	Date of action	Notes or Outcomes
1/31/2018	Thief hatch open	Close and latch thief hatch	1/31/2018	Remind pumper to close thief hatch

COLORADO
Department of Public Health & Environment

AIR POLLUTION CONTROL DIVISION

COMPLIANCE ORDER ON CONSENT

CASE NOS. 2021-119, 2022-020, 2022-073, 2022-155
AIRS NOS. 069-0173, 069-0180

IN THE MATTER OF PROSPECT ENERGY, LLC

The Colorado Department of Public Health and Environment ("CDPHE"), through the Air Pollution Control Division ("Division"), issues this Compliance Order on Consent ("Consent Order"), pursuant to the Division's authority under § 25-7-115(3)(b), C.R.S. of the Colorado Air Pollution and Prevention and Control Act, §§ 25-7-101 to 1309, C.R.S. ("the Act"), and its implementing regulations, 5 C.C.R. § 1001, et seq ("the Regulations") with the express consent of Prospect Energy, LLC ("Prospect"). The Division and Prospect may be referred to collectively as "the Parties" or individually as "a Party."

I. STATEMENT OF PURPOSE

The mutual objectives of the Parties in entering into this Consent Order are:

1. To establish compliance requirements and criteria for the continued operation of Prospect's following oil and gas well production facilities (collectively, "Facilities"):

   i. AIRS No. 069-0173, Krause Tank Battery, located 4.2 miles northeast of Highway 14 and US Highway 287, Larimer County, Colorado ("Krause Facility").

   ii. AIRS No. 069-0180, Fort Collins Tank Battery, located at NWNW Section 30, Township 8N, Range 68W, Larimer County, Colorado ("Fort Collins Facility").

2. To resolve the violations of the Act, as determined by the Division, and cited herein, in Notice of Violations issued to Prospect by the Division on December 6, 2021 and May 3, 2022, and in Compliance Advisories issued to Prospect by the Division on March 2, 2022 and August 9, 2022.

II. DIVISION'S FINDINGS OF FACT AND DETERMINATION OF VIOLATIONS

Based upon the Division's investigation into and review of the compliance issues identified herein, and in accordance with § 25-7-115(3), C.R.S., the Division has made the following determinations regarding violations of regulatory, statutory, and/or permit requirements associated with the Facilities.

3. At all times relevant to the violations cited herein, Prospect was an LLC in good standing and registered to conduct business in the State of Colorado.

4. Prospect owns and operates the Facilities.

5. The Krause Facility is subject to the terms and conditions of Colorado Construction Permit Number 19LR0685, Issuance 1 issued to Prospect on October 28, 2019, Final Approval issued September 3, 2020 ("Permit Number 19LR0685"); and Colorado General Construction Permit Number GP05, Version 3, Final Approval issued January 24, 2020 ("GP05").

6. The following emissions points located at the Krause Facility are relevant to this enforcement action:

AIRS Point	Point Description	Permit Number
002	Four (4) 300 bbl atmospheric crude oil storage tanks, controlled by an enclosed combustor.	GP08
003	Crude oil loadout operations, controlled by an enclosed combustor.	11LR1428.XP
004	Separator gas venting, controlled by an enclosed combustor.	19LR0685
005	Two (2) 400 bbl and one (1) 300 bbl produced water storage tanks, controlled by an enclosed combustor.	GP05

7. The Fort Collins Facility is subject to the terms and conditions of Colorado Construction Permit Number 19LR0686, Issuance 1 issued to Prospect on October 28, 2019, Final Approval issued May 4, 2020 ("Permit Number 19LR0686");

Colorado General Construction Permit Number GP05, Version 3 (“GP05”); and Colorado General Construction Permit Number GP08, Version 2 (“GP08”).

8. The following emissions points located at the Fort Collins Facility are relevant to this enforcement action:

AIRS Point	Point Description	Permit Number
002	Four (4) 500 bbl crude oil storage tanks, controlled by an enclosed combustor	GP08
003	Hydrocarbon liquid loading rack	N/A
004	Separator gas venting, controlled by an enclosed combustor	19LR0686
005	Two (2) 500 bbl and one (1) 300 bbl produced water storage tanks, controlled by an enclosed combustor	GP05

9. On November 15, 2021, Craig Giesecke, of the Division, conducted an inspection, pursuant to the Division's authority under § 25-7-111(2)(c), C.R.S., at the Krause Facility for the purpose of determining compliance with permit requirements, the Act, and the Regulations. Based on the inspection, and a review of records related to the Krause Facility, the Division issued an Immediate Notice of Violation to Prospect on December 6, 2021.

10. On January 28, 2022 and February 8, 2022, Inspector Giesecke conducted inspections, pursuant to the Division's authority under § 25-7-111(2)(c), C.R.S., at the Krause Facility for the purpose of determining compliance with permit requirements, the Act, and the Regulations. Based on the inspection, and a review of records related to the Krause Facility, the Division issued a Compliance Advisory to Prospect on March 2, 2022.

11. On April 5, 2022, the Division and Prospect met by teleconference to discuss the issues identified in the Immediate Notice of Violation and Compliance Advisory issued for the Krause Facility.

12. On April 8, 2022, Inspector Giesecke conducted an inspection, pursuant to the Division's authority under § 25-7-111(2)(c), C.R.S., at the Fort Collins Facility for the purpose of determining compliance with permit requirements, the Act, and the Regulations. Based on the inspection, and a review of records related to the Fort Collins Facility, the Division issued an Immediate Notice of Violation to Prospect on May 3, 2022.

13. On April 21, 2022, Sydney McLeod, of the Larimer County Department of Health and Environment, a duly delegated representative of the Division, conducted an inspection at the Fort Collins Facility for the purpose of determining compliance

with permit requirements, the Act, and the Regulations. Based on the inspection, and a review of records related to the Fort Collins Facility, the Division issued a Compliance Advisory to Prospect on August 9, 2022.

14. On August 24, 2022, the Division issued a Cease and Desist Order to Prospect ordering Prospect to temporarily discontinue any and all activities at the Krause Facility that emit or had the potential to emit air pollutants until Prospect could demonstrate to the Division the Krause Facility's full compliance with AQCC Regulations. On August 25, 2022, Prospect complied with the Cease and Desist Order and ceased operating the Krause Facility.

15. On September 14, 2022, the Division and Prospect met by teleconference to discuss the issues identified in the Immediate Notice of Violation and Compliance Advisory issued for the Fort Collins Facility as well as the conditions of the Cease and Desist Order for the Krause Facility.

16. On November 28, 2022, the Division terminated the Cease and Desist Order for the Krause Facility, following Prospect's fulfillment of the conditions of the Cease and Desist Order. On December 1, 2022, Prospect resumed full operation of the Krause Facility.

17. Based upon a review of information including the inspections, records related to the Facilities, and the information provided by Prospect, the Division has determined the following:

<u>Krause Facility</u>

a. Pursuant to AQCC Regulation Number 3, Part A, § II.A.1, no person shall allow emission of air pollutants from, or construction, modification or alteration of, any facility, process, or activity which constitutes a stationary source, except residential structures, from which air pollutants are, or are to be, emitted unless and until an Air Pollutant Emission Notice ("APEN") and the associated APEN fee has been filed with the Division with respect to such emission. Prospect failed to file an APEN for the produced water tanks at the Krause Facility (now AIRS Point 005) until May 27, 2021, in violation of AQCC Regulation 3, Part A, § II.A.[1]

b. Pursuant to AQCC Regulation Number 3, Part A, § II.C.1.e, a revised APEN shall be filed with the Division before the current APEN expires. Pursuant to AQCC Regulation Number 3, Part A, §

[1] The produced water tanks were previously APEN and permit exempt. Prospect reported uncontrolled actual VOC emissions of 44.7 tons per year in the APEN submitted on May 27, 2021, based on 2020 emissions data.

II.C.3.a, a revised APEN shall be submitted no later than thirty days before the five-year term expires. Prospect submitted an APEN for AIRS Point 002 on January 4, 2016, and a revised APEN was due no later than December 5, 2020. Prospect failed to submit a revised APEN for AIRS Point 002 until May 27, 2021, in violation of AQCC Regulation Number 3, Part A, §§ II.C.1.e and II.C.3.a.

c. Pursuant to AQCC Regulation Number 3, Part B, § II.A.1, no person shall construct, modify, or operate any stationary source or commence the conduct of any such activity without first obtaining or having a valid construction permit from the Division. Prospect failed to obtain a permit for the produced water tanks at the Krause Facility (now AIRS Point 005) until May 27, 2021, in violation of AQCC Regulation 3, Part B, § II.A.1.[1]

d. Pursuant to AQCC Regulation Number 7, Part D, § I.C.1.b, all hydrocarbon liquids and produced water collection, storage, processing and handling operations, regardless of size, must be designed, operated and maintained so as to minimize leakage of volatile organic compounds to the atmosphere to the maximum extent practicable. The following emissions were observed at the Krause Facility either as a result of completing a site investigation in response to an odor complaint or otherwise reported by the company:

Table 1: Krause Facility Observed Emission Leaks

Location of emissions	Dates emissions observed	Emissions observed by	Repair dates
Center Produced Water Tank Thief Hatch	12/18/2019	Prospect	12/18/2019
	3/2/2021	Prospect	3/2/2021
	6/7/2021	Prospect	Unrecorded
	11/15/2021	Division	1/31/2022
	2/28/2023	Division	2/28/2023
Center Produced Water Tank Roof (holes)	3/2/2021	Prospect	3/5/2021
	6/7/2021	Prospect	Unrecorded
	9/13/2021	Prospect	1/31/2022
	11/15/2021	Division	11/24/2021

Center Produced Water Tank Vapor Line Connection Point	9/29/2022	Division	9/29/2022
East Produced Water Tank Thief Hatch	1/28/2021	Prospect	1/29/2021
	3/2/2021	Prospect	3/2/2021
	6/7/2021	Prospect	Unrecorded
	11/15/2021	Division	1/12/2022
	1/5/2023	Division	1/6/2023
	2/28/2023	Division	2/28/2023
East Produced Water Tank Roof (holes)	3/2/2021	Prospect	3/5/2021
	6/7/2021	Prospect	1/12/2022
	9/13/2021	Division	1/31/2022
West Produced Water Tank Thief Hatch	9/27/2022	Division	9/29/2022
Oil Tank #1 Thief Hatch	3/2/2021	Prospect	3/4/2021
	3/31/2021	Prospect	4/1/2021
	6/17/2022	Division	6/25/2022
	8/11/2022	Division	8/15/2022
	12/7/2022	Prospect	12/7/2022
	2/28/2023	Division	2/28/2023
Oil Tank #2 Thief Hatch	3/2/2021	Prospect	3/4/2021
	3/3/2022	Division	3/3/2022
	6/17/2022	Division	6/25/2022
	8/11/2022	Division	8/15/2022
Oil Tank #3 Thief Hatch	3/2/2021	Prospect	3/4/2021
	6/7/2021	Prospect	6/9/2021
	1/28/2022	Division	2/9/2022
	3/3/2022	Division	3/3/2022
	8/11/2022	Division	8/15/2022
Oil Tank #4 Thief Hatch	3/2/2021	Prospect	3/4/2021
	6/7/2021	Prospect	6/9/2021
	3/3/2022	Division	3/3/2022
	8/11/2022	Division	8/15/2022
	12/7/2022	Prospect	12/7/2022
	1/5/2023	Division	1/5/2023

As indicated above, Prospect failed to operate and maintain hydrocarbon liquid and produced water storage operations so as to minimize leakage of volatile organic compounds to the atmosphere to the maximum extent practicable, violating AQCC Regulation Number 7, Part D, § I.C.1.b.

e. Pursuant to AQCC Regulation Number 7, Part D, § XVII.C.2.a (2019) and AQCC Regulation Number 7, Part D, § II.C.2.a (2020), for storage tanks, Prospect must route all hydrocarbon emissions to air pollution control equipment, and must operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation, unless venting is reasonably required for maintenance, gauging, or safety of personnel and equipment. The following emissions were observed at the Krause Facility either as a result of completing a site investigation in response to an odor complaint or otherwise reported by the company:

Table 2: Krause Facility Observed Emission Venting

Location of emissions	Dates emissions observed	Emissions observed by	Repair dates
Center Produced Water Tank Thief Hatch	12/18/2019	Prospect	12/18/2019
	3/2/2021	Prospect	3/2/2021
	6/7/2021	Prospect	Unrecorded
	11/15/2021	Division	1/31/2022
	2/28/2023	Division	2/28/2023
Center Produced Water Tank Roof (holes)	3/2/2021	Prospect	3/5/2021
	6/7/2021	Prospect	Unrecorded
	9/13/2021	Prospect	1/31/2022
	11/15/2021	Division	11/24/2021
Center Produced Water Tank Vapor Line Connection Point	9/29/2022	Division	9/29/2022
East Produced Water Tank Thief Hatch	1/28/2021	Prospect	1/29/2021
	3/2/2021	Prospect	3/2/2021
	6/7/2021	Prospect	Unrecorded
	11/15/2021	Division	1/12/2022
	1/5/2023	Division	1/6/2023
	2/28/2023	Division	2/28/2023
	3/2/2021	Prospect	3/5/2021

East Produced Water Tank Roof (holes)	6/7/2021	Prospect	1/12/2022
	9/13/2021	Division	1/31/2022
West Produced Water Tank Thief Hatch	9/27/2022	Division	9/29/2022
Oil Tank #1 Thief Hatch	3/2/2021	Prospect	3/4/2021
	3/31/2021	Prospect	4/1/2021
	6/17/2022	Division	6/25/2022
	8/11/2022	Division	8/15/2022
	12/7/2022	Prospect	12/7/2022
	2/28/2023	Division	2/28/2023
Oil Tank #2 Thief Hatch	3/2/2021	Prospect	3/4/2021
	3/3/2022	Division	3/3/2022
	6/17/2022	Division	6/25/2022
	8/11/2022	Division	8/15/2022
Oil Tank #3 Thief Hatch	3/2/2021	Prospect	3/4/2021
	6/7/2021	Prospect	6/9/2021
	1/28/2022	Division	2/9/2022
	3/3/2022	Division	3/3/2022
	8/11/2022	Division	8/15/2022
Oil Tank #4 Thief Hatch	3/2/2021	Prospect	3/4/2021
	6/7/2021	Prospect	6/9/2021
	3/3/2022	Division	3/3/2022
	8/11/2022	Division	8/15/2022
	12/7/2022	Prospect	12/7/2022
	1/5/2023	Division	1/5/2023

As indicated above, Prospect failed to route all hydrocarbon emissions to air pollution control equipment and operate without venting hydrocarbon emissions from storage tank thief hatches and pressure relief devices, violating AQCC Regulation Number 7, Part D, § XVII.C.2.a (2019) and AQCC Regulation Number 7, Part D, § II.C.2.a (2020).

f. Pursuant to AQCC Regulation Number 7, Part D, § II.E.4.d, beginning calendar year 2020, Prospect must inspect components for leaks using an approved instrument monitoring method (AIMM) in accordance with the inspection frequency in Table 3. Based on reported uncontrolled actual VOC emissions, Prospect was required to complete AIMM inspections on a quarterly basis from January 2020 through April 2021, and on a monthly basis beginning in May 2021[2]. Prospect failed to conduct AIMM inspections in the following periods:

Table 3: Krause Facility Missed AIMM Inspections	
Required AIMM frequency	**Periods missed**
Quarterly	January-March 2020
	April-June 2020
	July-September 2020
	October-December 2020
Monthly	May 2021
	July 2021
	August 2021
	October 2021

Prospect failed to complete required AIMM inspections, as shown in the table above, violating AQCC Regulation Number 7, Part D, § II.E.4.d.

g. Pursuant to AQCC Regulation Number 2, Part A, § I.B, Prospect shall not cause or allow the emission of odorous air contaminants from any single source such as to result in odors that are detectable after the odorous air has been diluted with fifteen (15) or more volumes of odor free air ("15:1 d/t"). On January 28, 2022, Larimer County observed odors in excess of the 15:1 d/t limit, as detailed below.

Table 4: Krause Facility Odor Readings		
Time	**Odor reading**	**Location**
12:30 PM	No odor detected	Upwind
1:10 PM	No odor detected	Upwind
1:30 PM	32:1	Downwind
1:31 PM	32:1	Downwind
1:50 PM	32:1	Downwind

[2] The Krause Facility is located within 1,000 feet of an occupied area. Prior to May 2021, Prospect reported less than 12 tons per year of VOC emissions from the highest emitting storage tank at the Krause Facility. In May 2021, Prospect submitted an APEN for AIRS Point 005, which included estimated annual uncontrolled actual VOC emissions above 12 tons per year; making the Krause Facility then subject to monthly AIMM inspections.

2:00 PM	32:1	Downwind
2:08 PM	No odor detected	Upwind

On January 28, 2022, Prospect failed to ensure that emission of odorous air contaminants remained below the 15:1 d/t limit, violating AQCC Regulation Number 2, Part A, § I.B.

h. Pursuant to Permit Number 19LR0685, Condition 11 and GP05, Condition II.B.2, the permit number and ten digit AIRS ID number assigned by the Division shall be marked on AIRS Points 004 and 005 for ease of identification. Until February 18, 2022, Prospect failed to mark the applicable permit numbers and AIRS IDs on AIRS Points 004 and 005, violating Permit Number 19LR0685, Condition 11 and GP05, Condition II.B.2.

<u>Fort Collins Facility</u>

i. Pursuant to AQCC Regulation Number 3, Part A, § II.A.1, no person shall allow emission of air pollutants from, or construction, modification or alteration of, any facility, process, or activity which constitutes a stationary source, except residential structures, from which air pollutants are, or are to be, emitted unless and until an Air Pollutant Emission Notice ("APEN") and the associated APEN fee has been filed with the Division with respect to such emission. Reported throughput and emissions by Prospect indicate that the produced water tanks reached two tons of VOC emissions in December 2019. Until May 27, 2021, Prospect failed to file an APEN for the produced water tanks at the Fort Collins Facility (AIRS Point 005), in violation of AQCC Regulation Number 3, Part A, § II.A.1.

j. Pursuant to AQCC Regulation Number 3, Part A, § II.C.1.e, a revised APEN shall be filed with the Division before the current APEN expires. Pursuant to AQCC Regulation Number 3, Part A, § II.C.3.a, a revised APEN shall be submitted no later than thirty days before the five-year term expires. Prospect previously submitted an APEN for AIRS Point 002 on April 26, 2016, and a revised APEN was due no later than March 27, 2021. Prospect failed to submit a revised APEN for AIRS Point 002 until May 27, 2021, in violation of AQCC Regulation Number 3, Part A, §§ II.C.1.e and II.C.3.a.

k. Pursuant to AQCC Regulation Number 3, Part B, § II.A.1, no person shall construct, modify, or operate any stationary source or commence the conduct of any such activity without first obtaining or having a valid construction permit from the Division. Reported throughput and emissions by Prospect indicate that the produced water tanks reached two tons of VOC emissions in December 2019. Until May 27, 2021, Prospect failed to obtain a construction permit for the produced water tanks at the Fort Collins Facility (AIRS Point 005), in violation of AQCC Regulation Number 3, Part B, § II.A.1.

l. Pursuant to AQCC Regulation Number 7, Part D, § I.C.1.b; GP05, Condition IV.B.3; and GP08, Condition IV.B, all hydrocarbon liquids and produced water collection, storage, processing, and handling operations, regardless of size, must be designed, operated, and maintained so as to minimize emission of volatile organic compounds to the atmosphere to the maximum extent practicable.

    i. On April 8, 2022, the Division observed emissions coming from a hole in the roof of the southwest crude oil storage tank. The hole in the tank was repaired following the inspection on April 8, 2022.

    ii. On May 9, 2022, an issue with the water level control system at the Fort Collins Facility resulted in the excessive build-up of produced water in the produced water tanks (AIRS Point 005). The produced water tanks overflowed, causing produced water to flow into the Fort Collins Facility’s Tornado TEC-4-CS enclosed combustion device (ECD), resulting in a fire and visible emissions from the ECD.

   Therefore, Prospect failed to operate and maintain hydrocarbon liquid and produced water storage operations so as to minimize emission of volatile organic compounds to the atmosphere to the maximum extent practicable, violating AQCC Regulation Number 7, Part D, § I.C.1.b; GP05, Condition IV.B.3; and GP08, Condition IV.B.

m. Pursuant to AQCC Regulation Number 7, Part D, § I.C.1.d; Permit Number 19LR0686, Condition 13; GP05, Condition IV.A; and GP08, Condition IV.A.2, if a flare or other combustion device is used to control emissions of volatile organic compounds, it must be enclosed, have no visible emissions, and be designed so that an observer can, by means of visual observation from the outside of the enclosed flare or combustion device, or by other convenient means, such as a continuous monitoring device, approved by the Division, determine whether it is operating properly. On May 9, 2022, visible emissions were observed coming from the Fort Collins Facility's Tornado TEC-4-CS enclosed combustion device. Therefore, Prospect failed to ensure that the combustion device at the Fort Collins Facility had no visible emissions, violating AQCC Regulation Number 7, Part D, § I.C.1.d; Permit Number 19LR0686, Condition 13; GP05, Condition IV.A; and GP08, Condition IV.A.2.

n. Pursuant to AQCC Regulation Number 7, Part D, § II.C.2.a, for storage tanks, Prospect must route all hydrocarbon emissions to air pollution control equipment, and must operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation, unless venting is reasonably required for maintenance, gauging, or safety of personnel and equipment. On April 8, 2022, the Division observed emissions coming from a hole in the roof of the southwest crude oil storage tank. Therefore, Prospect failed to route all hydrocarbon emissions to air pollution control equipment and operate without venting hydrocarbon emissions from storage tank thief hatches and pressure relief devices, violating AQCC Regulation Number 7, Part D, § II.C.2.a.

   Prospect repaired the hole in the tank following the inspection on April 8, 2022.

o. Pursuant to AQCC Regulation Number 7, Part D, § II.E.4.d, Prospect must inspect Facility components for leaks using an approved instrument monitoring method (AIMM). Pursuant to AQCC Regulation Number 7, Part D, § II.E.4.g, the estimated uncontrolled actual VOC emissions from the highest emitting storage tank at the facility determines the frequency at which inspections must be performed. The Fort Collins Facility is located within 1,000 feet of an occupied area. Based on reported VOC emissions, the crude oil tanks (AIRS Point 002) had uncontrolled VOC emissions between 2 and 12 tons per year in all rolling 12-month periods in 2020. The Fort Collins Facility was therefore subject to quarterly AIMM inspections in 2020. Thereafter, the produced water tanks (AIRS Point 005) had uncontrolled VOC emissions greater than 12 tons per year in all rolling 12-month periods from January 2021 through at least March 2022.

Therefore, the Fort Collins Facility was subject to monthly AIMM inspections in 2021 through at least March 2022. Prospect failed to complete quarterly AIMM inspections in the second, third, and fourth quarters of 2020; and failed to complete monthly AIMM inspections in January, February, April, May, July, August, October, and November of 2021, violating AQCC Regulation Number 7, Part D, § II.E.4.d.

p. Pursuant to Permit Number 19LR0686, Condition 11 and GP05, Condition II.B.2, the permit number and ten digit AIRS ID number assigned by the Division shall be marked on AIRS Points 004 and 005 for ease of identification. At the time of the inspection on April 21, 2022, AIRS Points 004 and 005 were not marked with the applicable permit numbers or AIRS ID numbers. Prospect failed to mark AIRS Points 004 and 005 with the applicable permit numbers and AIRS IDs, violating Permit Number 19LR0686, Condition 11 and GP05, Condition II.B.2.

   Prospect marked AIRS Points 004 and 005 following the inspection on April 21, 2022.

q. Pursuant to GP05, Condition V.B.4 and V.B.4.b, Prospect must maintain records that clearly demonstrate compliance with the emission limits in the permit. Compliance with emission limits must be determined by recording the annual emissions from each emission unit on a rolling 12-month total. Prospect provided the Division with Fort Collins Facility emissions records for the inspection conducted on April 21, 2022. Upon review of the provided records, the Division found that rolling 12-month emissions were calculated inaccurately for the produced water tanks (AIRS Point 005). Prospect failed to accurately calculate emissions and provide the Division with an accurate emissions compliance record for the Fort Collins Facility, violating GP05, Condition V.B.4 and V.B.4.b.

18. The Division and Prospect entered into settlement discussions for the violations as determined by the Division. The Parties reached a settlement as detailed in this Consent Order.

III. ORDER and AGREEMENT

Based on the foregoing factual and legal determinations, pursuant to its authority under § 25-7-115, C.R.S., and as a result of the violations cited herein, the Division orders Prospect to comply with all provisions of this Consent Order, including all requirements set forth below.

19. Prospect agrees to the terms and conditions of this Consent Order. Prospect agrees that this Consent Order constitutes an order issued pursuant to § 25-7-115, C.R.S., and is an enforceable requirement of Part 1 of the Act. Prospect also agrees not to challenge directly or collaterally, in any judicial or administrative proceeding brought by the Division to enforce this Consent Order or by Prospect against the Division:

i. the issuance of this Consent Order;

ii. the factual and legal determinations made by the Division herein; and

iii. the Division's authority to bring, or the court's jurisdiction to hear, any action to enforce the terms of this Consent Order under the Act.

20. Notwithstanding the above, Prospect does not admit to any of the factual or legal determinations made by the Division herein, and any action undertaken by Prospect pursuant to this Consent Order shall not constitute an admission of liability by Prospect with respect to the condition or operation of the Facilities.

Compliance Requirements

Krause Facility

21. Effective immediately, and without limitation, Prospect shall comply with the Act and the Regulations in the regulation and control of air pollutants at the Krause Facility.

22. Effective immediately, and without limitation, Prospect must comply with the provisions of AQCC Regulation 2 concerning odorous emissions including, but not limited to, the 15:1 ratio for all other land use areas at the Krause Facility.

23. Effective immediately, and without limitation, Prospect must comply with the provisions of the Krause Facility's most recent Odor Management Plan, as approved by the Division. The most recent Odor Management Plan for the Krause Facility was submitted by Prospect on January 17, 2024, and approved by the Division on January 31, 2024. Prospect may, in its discretion, submit an amended Odor

Management Plan to the Division for approval but, at all times, Prospect shall comply with the provisions of the most recently approved Odor Management Plan unless and until an amended plan is approved by the Division.

24. Prospect has commenced the preparation and implementation of processes to adhere to the Storage Tank and VCS Guidelines for the Krause Facility. Within thirty (30) days of the effective date of this Consent Order, Prospect must finalize this process by completing the following items:

i. Prospect must include in its Written Procedures a requirement in its Predictive Analysis procedures to review the effectiveness of any thief hatch or seals used to inhibit corrosion and/or effects of hydrogen sulfide gas (H_2S) on the materials at the Krause Facility.

ii. Cooperate with the Division to finalize and implement all procedures to comply with the VCS guidelines. Cooperation shall include, but not be limited to, responding to any Division requests for information within five (5) business days of receipt.

25. Upon the effective date of this Consent Order, and without limitation, Prospect must comply with the most recently approved Storage Tank Emission Management (STEM) plan for the Krause Facility. Within thirty (30) days of the effective date of this Consent Order, Prospect must revise and submit to the Division a STEM plan for the Krause Facility that incorporates a predictive analysis for the control of H_2S emissions. Upon Division approval, Prospect must comply with the revised STEM plan for the Krause Facility.

26. Within thirty (30) days of the effective date of this Consent Order, Prospect must install an emissions monitoring and alert system at the Krause Facility for the monitoring of H_2S. If the monitoring system detects H_2S, Prospect must take the following actions at the listed concentrations:

i. Between **0 ppm and 70 ppb,** over a duration of at least one hour, Prospect must follow the odor response procedures as detailed in the Krause Facility's Odor Management Plan.

ii. Between **70 ppb and 20 ppm,** over a duration of at least one hour, Prospect must complete an approved instrument monitoring method (AIMM) inspection within twelve (12) hours of initial detection to identify the source of the H_2S. Within twelve (12) hours of identification of the source of the H_2S, Prospect must eliminate or reduce the source of the H_2S to below 70 ppb. If Prospect is unable to eliminate or reduce the H_2S within twenty-four (24) hours of initial detection, Prospect must discontinue any and all activities at the

Krause Facility that emit or have potential to emit air pollutants. Prospect may not recommence operation and the emission of pollutants at the Krause Facility unless and until Prospect demonstrates to the Division that detectable H_2S is below 70 ppb. Additionally, Prospect must follow the odor response procedures as detailed in the Krause Facility's Odor Management Plan.

iii. At **20 ppm or greater,** over a duration of at least 30 minutes, Prospect must immediately discontinue any and all activities at the Krause Facility that emit or have potential to emit air pollutants. Prospect may not recommence operation and the emission of pollutants at the Krause Facility unless and until Prospect demonstrates to the Division that detectable H_2S is below 70 ppb. Additionally, Prospect must follow the odor response procedures as detailed in the Krause Facility's current Odor Management Plan.

iv. Prospect must maintain records of all responses required by Paragraphs 26.i-iii.

27. Prospect must conduct quarterly H_2S concentration sampling at the Krause Facility, in accordance with the following stipulations:

i. The first sample must be taken within thirty (30) days of the effective date of this Consent Order. Thereafter, sampling must occur at least every three (3) months, on a calendar basis.

ii. Sampling must be conducted using Draeger tubes or equivalent gas detection tubes. The detection tubes must be calibrated to a span capable of detecting H2S within the range of detection observed during previous sampling.

iii. Each sampling event must consist of three (3) samples taken from heater-treated gas, produced water tank headspace, and oil tank headspace.

Prospect must conduct the quarterly sampling consistent with this Paragraph until a revised Construction Permit is issued for the Krause Facility.

28. Effective immediately, and without limitation, Prospect must not allow the release of any liquid substance from knockout vessels (also known as "scrubbers") at the Krause Facility. All liquids in the knockout vessels must be routed to storage tanks, liquid flow lines, or other enclosed vessels.

29. As soon as practicable, but in any event within sixty (60) days of the effective date of this Consent Order, Prospect must install high-performance thief

hatches on all storage tanks at the Krause Facility (AIRS Points 002 and 005). Prospect must install thief hatches that are manufactured in a manner so as to be resistant to corrosive substances, including H_2S, such as thief hatches that contain a fluoroelastomer-based gasket seal and/or an anodized vacuum pallet. As of the date of this Consent Order, Oil Tanks #1 and #2 have the fluoroelastomer-based gasket seal on both the pressure relief and vacuum relief gasket seals.

30. Beginning upon the effective date of this Consent Order, Prospect must conduct infrared (IR) camera inspections at the Krause Facility at least every two (2) weeks. If Prospect observes emissions with the IR camera, Prospect must make an initial attempt to repair the source of the emissions within twenty-four (24) hours of the inspection. Within five (5) days of the IR inspection, Prospect must successfully complete final repair of the source of the observed emissions and verify repair with an approved instrument monitoring method. If Prospect is unable to successfully repair the source of the emissions within five (5) days of discovery, Prospect must discontinue any and all activities of the affected equipment that emit or has potential to emit air pollutants. Prospect may not recommence operation and the emission of the affected equipment unless and until Prospect demonstrates to the Division that the source of the emissions has been eliminated. Prospect shall follow the recordkeeping requirements of AQCC Regulation Number 7, Part B, § I.L.6 in documenting the observed emissions and efforts taken to eliminate the emissions. Prospect must conduct IR inspections consistent with this Paragraph until a revised Construction Permit is issued for the Krause Facility.

31. Within ninety (90) days of the effective date of this Consent Order, Prospect must submit an application to convert the General Construction Permits registered for the Krause Facility to a Construction Permit. This deadline may be extended via modification of this Consent Order as described in Section XI. Prospect must cooperate with the Division in submitting a complete and accurate application. Cooperation includes, but is not limited to, responding to all Division requests for information within fourteen (14) calendar days of receipt, which may be extended if agreed to by the Division in writing.

32. Within twelve (12) months of the effective date of this Consent Order, Prospect must obtain a Construction Permit for the equipment at the Krause Facility currently registered under General Construction Permits. This deadline may be extended via modification of this Consent Order as described in Section XI. Prospect must cooperate with the Division in obtaining the permit. Cooperation includes, but is not limited to, responding to all Division requests for information within fourteen (14) calendar days of receipt, which may be extended if agreed to by the Division in writing.

33. Prospect must maintain records of compliance with all requirements in Paragraphs 23 through 32 for a period of five (5) years, and make the records

available to the Division within fourteen (14) calendar days of request.

34. Beginning upon the effective date of this Consent Order and ending December 31, 2026, Prospect must submit to the Division a periodic semi-annual report ("SAR") within sixty (60) days after the end of each half of the calendar year (January through June, and July through December) for the Krause Facility. Each SAR must contain, at a minimum, the following information:

i. Records kept per the Krause Facility's Odor Management Plan odor response recordkeeping requirements, including, but not limited to:

a. The date, time, and method of odor observations.

b. The investigated root cause of observed odors.

c. The dates and actions taken to eliminate observed odors and the dates and methods the odors were successfully eliminated.

ii. Any deviations and revisions of the STEM plan for the Krause Facility during the reporting period. The SAR must include an explanation of the deviations of the STEM plan and actions taken, or to be taken, to prevent or resolve such deviations and an explanation of revisions made to the STEM plan.

iii. Any instances in which the Krause Facility's H_2S monitoring system detected H_2S within any of concentration ranges denoted in Paragraph 26, and the applicable corrective actions taken by Prospect.

iv. Any instances in which thief hatches, thief hatch gaskets, or thief hatch components are replaced on produced water storage tanks and oil storage tanks at the Krause Facility. The information must include identification of the reasons for the replacement of the thief hatch (or gasket or other component) and a full description of the type of replacement thief hatch (or gasket or other component) installed in accordance with Paragraph 29.

v. The dates and results of IR camera inspections completed as required in Paragraph 30, and if emissions are observed, the applicable corrective actions taken by Prospect in response.

vi. A description of any non-compliance with the requirements of this Consent Order during the reporting period, and an explanation of the likely cause and remedial actions taken, or to be taken, to prevent or resolve such violations.

35. Prospect must submit a Notice of Completion to the Division within thirty (30) days of completion of all requirements. The Notice of Completion shall identify the date of completion of each requirement.

Fort Collins Facility

36. Effective immediately, and without limitation, Prospect shall comply with the Act and the Regulations in the regulation and control of air pollutants at the Fort Collins Facility.

37. Prospect has commenced the preparation and implementation of processes to adhere to the Storage Tank and VCS Guidelines for the Fort Collins Facility. Within thirty (30) days of the effective date of this Consent Order, Prospect must finalize this process by completing the following items:

i. Submit notification to the Division of intent to follow the Storage Tank and VCS Guidelines for the Fort Collins Facility.

ii. Cooperate with the Division to finalize and implement all procedures to comply with the VCS guidelines. Cooperation shall include, but is not limited to, responding to any Division requests for information within five (5) business days of receipt.

38. Upon the effective date of this Consent Order, and without limitation, Prospect must comply with the most recently approved Storage Tank Emission Management (STEM) plan for the Fort Collins Facility.

39. Prospect must maintain records of compliance with all requirements in Paragraphs 37 through 38 for a period of five (5) years, and make the records available to the Division within fourteen (14) calendar days of request.

40. Beginning upon the effective date of this Consent Order and ending December 31, 2026, Prospect must submit to the Division a periodic semi-annual report ("SAR") within sixty (60) days after the end of each half of the calendar year (January through June, and July through December) for the Fort Collins Facility. Each SAR must contain, at a minimum, the following information:

i. Any deviations and revisions of the STEM plan for the Fort Collins Facility during the reporting period. The SAR must include an explanation of the deviations of the STEM plan and actions taken, or to be taken, to prevent or resolve such deviations and an explanation of revisions made to the STEM plan.

ii. A description of any non-compliance with the requirements of this

Consent Order during the reporting period, and an explanation of the likely cause and remedial actions taken, or to be taken, to prevent or resolve such violations.

41. All documents submitted under this Consent Order shall use the same titles as stated in this Consent Order, and shall reference both the case number(s) and the number of the paragraph pursuant to which the document is required. Unless otherwise specifically provided herein, no document submitted for Division approval under this Consent Order may be implemented unless and until written approval is received from the Division. Any approval by the Division of a document submitted under this Consent Order is effective upon receipt by Prospect. All approved documents, including all procedures and schedules contained in the documents, are hereby incorporated into this Consent Order and shall constitute enforceable requirements under the Act.

Administrative Penalty Requirements

42. Based upon the factors set forth in § 25-7-122, C.R.S., the Division has determined an administrative penalty in the amount of **Three Hundred Thirty-Seven Thousand Fifty Dollars ($337,050.00)** against Prospect is appropriate and consistent with the Division's policies for violations of the Act and the Regulations cited in Section II of this Consent Order. Prospect agrees to pay the sum of $337,050.00 in administrative penalties. All penalty payments required by this Consent Order must be made by certified, corporate, or cashier's check drawn to the order of "Colorado Department of Public Health and Environment" and delivered to the attention of the Enforcement Unit Supervisor, Air Pollution Control Division, 4300 Cherry Creek Drive South, APCD-SS-B1, Denver, Colorado 80246-1530.

43. The penalty in Paragraph 42 may be paid in up to four installments:

a. Prospect must pay thirty thousand dollars ($30,000) within 30 days of the effective date of the Consent Order.
b. Prospect must pay eighty thousand dollars ($80,000) on or before June 30, 2024.
c. Prospect must pay one hundred ten thousand dollars ($110,000) on or before September 30, 2024.
d. Prospect must pay one hundred seventeen thousand fifty dollars ($117,050) on or before December 31, 2024.

44. If Prospect intends to complete a sale or transfer pursuant to Section X, Prospect must pay the remaining balance of $337,050.00 prior to the completion of the sale or transfer.

45. If Prospect seeks to terminate this Consent Order pursuant to Section XII, Prospect must pay the remaining balance of the $337,050.00 prior to seeking

Division approval for termination.

46. The Division's willingness to accept installment payments is expressly conditioned upon Prospect's continued payments in accordance with the schedule set forth above. Failure to make payments in accordance with this installment schedule shall constitute a violation of this Order. Should Prospect fail to make any installment payment, the entire administrative penalty, at the option of the Division, shall become due and payable to the Division ten (10) days after the Division notifies the Prospect that the balance of the administrative penalty is due.

IV. SCOPE AND EFFECT OF CONSENT ORDER

47. The Parties agree and acknowledge that this Consent Order constitutes a full and final settlement of the violations cited herein. This Consent Order is a final agency action. Prospect agrees not to challenge the terms and conditions of this Consent Order in any proceeding before any administrative body or any judicial forum, whether by way of direct judicial review or collateral challenge.

48. This Consent Order shall be enforceable by either Party in the same manner as if the Division had entered this Consent Order without agreement by Prospect. The Parties agree that any violation of the provisions of this Consent Order by Prospect concerning the Act, or the Regulations, shall be a violation of a final order of the Division for the purposes of §§ 25-7-115, 121, and 122, C.R.S., and may result in the assessment of civil penalties consistent with § 25-7-115, C.R.S., per day for each day of such violation.

49. The Parties' obligations under this Consent Order are limited to the matters expressly stated herein or in approved submissions required hereunder. All submissions made pursuant to this Consent Order are incorporated into this Consent Order and become enforceable under the terms of this Consent Order as of the date of approval by the Division.

50. The Division's approval of any submission, standard, or action under this Consent Order shall not constitute a defense to, or an excuse for, any prior violation of any requirement under the Act, the Regulations, or any subsequent violation of any requirement of this Consent Order, the Act, or the Regulations.

51. Entering into this Consent Order shall not constitute an admission of violation of any air quality laws by Prospect, nor shall the Division or any third party infer it to be such an admission by Prospect in any administrative or judicial proceeding. Notwithstanding the foregoing or anything in this Consent Order to the contrary, the violations included in this Consent Order will constitute part of Prospect's compliance history for any purpose for which such history is relevant,

including considering the violations described above in assessing a penalty for any subsequent violations, in accordance with the provisions of § 25-7-122, C.R.S., against Prospect.

52. Prospect shall comply with all applicable Federal, State, and/or local laws and regulations and shall obtain all necessary approvals or permits to conduct the investigation and remedial activities required by this Consent Order and perform its obligations required hereunder. The Division makes no representation with respect to approval and permits required by Federal, State, or local laws or regulations other than those specifically referred to herein.

53. Nothing herein shall be construed as prohibiting, altering, or in any way limiting the ability of the Division to seek any other remedies or sanctions available by virtue of Prospect's violation of this Consent Order or of the statutes and regulations upon which this Consent Order is based, or for Prospect's violation of any applicable provision of law.

V. LIMITATION RELEASES AND RESERVATION OF RIGHTS AND LIABILITY

54. Upon the effective date of this Consent Order, this Consent Order shall stand in lieu of any other enforcement action by the Division with respect to the violations cited herein. This Consent Order does not grant any release of liability for any violations, regardless of when they occurred, that are not cited in this Consent Order. The Division reserves the right to bring any action it deems necessary to enforce this Consent Order, including actions for penalties and/or injunctive relief.

55. Nothing in this Consent Order shall preclude the Division from imposing additional requirements necessary to protect human health or the environment and to effectuate the purposes of this Consent Order. Nor shall anything in this Consent Order preclude the Division from imposing additional requirements in the event additional information is discovered that indicates such requirements are necessary to protect human health or the environment.

56. Prospect reserves its rights and defenses regarding liability in any proceedings regarding the Facilities other than proceedings to enforce this Consent Order.

57. Upon the effective date of this Consent Order, Prospect releases and covenants not to sue the State of Colorado as to all common law or statutory claims or counterclaims arising from, or relating to, the violations of the Act or the Regulations specifically addressed herein.

58. Prospect shall not seek to hold the State of Colorado or its employees, agents, or representatives liable for any injuries or damages to persons or property

resulting from acts or omissions of Prospect, or those acting for or on behalf of Prospect, including its officers, employees, agents, successors, representatives, contractors or consultants in carrying out activities pursuant to this Consent Order. Prospect shall not hold out the State of Colorado or its employees, agents or representatives as a party to any contract entered into by Prospect in carrying out activities pursuant to this Consent Order. Nothing in this Consent Order shall constitute an express or implied waiver of immunity otherwise applicable to the State of Colorado, its employees, agents, or representatives.

59. The Division reserves the right to bring any action or to seek civil or administrative penalties for any past, present, or future violations of the Act and the Regulations, not specifically addressed herein. Further, the Division has the right to bring any action to enforce this Consent Order and to seek authorized penalties for any violation of this Consent Order.

VI. FORCE MAJEURE

60. Prospect shall perform the requirements of this Consent Order within the schedules and time limits set forth herein and in any approved plan unless the performance is prevented or delayed by events that constitute a force majeure. A force majeure is defined as any event arising from causes which are not reasonably foreseeable, which are beyond the control of Prospect, and which cannot be overcome by due diligence.

61. Unless otherwise provided in the Act or the Regulations, within seventy-two (72) hours of the time that Prospect knows or has reason to know of the occurrence of any event which Prospect has reason to believe may prevent Prospect from timely compliance with any requirement under this Consent Order, Prospect shall provide verbal notification to the Division. Within four (4) calendar days of the time that Prospect provides such verbal notification, Prospect shall submit to the Division a written description of the event causing the delay, the reasons for and the expected duration of the delay, and actions which will be taken to mitigate the duration of the delay.

62. The burden of proving that any delay was caused by a force majeure shall at all times rest with Prospect. If the Division agrees that a force majeure has occurred, the Division will so notify Prospect. The Division will also approve or disapprove of Prospect's proposed actions for mitigating the delay. If the Division does not agree that a force majeure has occurred, or if the Division disapproves of Prospect's proposed actions for mitigating the delay, it promptly shall provide a written explanation of its determination to Prospect.

63. Delay in the achievement of one requirement shall not necessarily justify or excuse delay in the achievement of subsequent requirements. In the event

any performance under this Consent Order is found to have been delayed by an event of force majeure, Prospect shall perform the requirements of this Consent Order that were not delayed by the force majeure with all due diligence.

VII. DISPUTE RESOLUTION

64. If the Division determines that additional requirements are necessary, that a violation of this Consent Order has occurred, that a force majeure has not occurred, or that the actions taken by Prospect to mitigate the delay caused by a force majeure are inadequate, the Division shall provide a written explanation of its determination to Prospect. Within fifteen (15) calendar days of receipt of the Division's determination, Prospect shall:

a. Submit a notice of acceptance of the determination; or

b. Submit a notice of dispute of the determination.

If Prospect fails to submit either of the above notices within the specified time, it will be deemed to have accepted the Division's determination.

65. If Prospect files any notice of dispute, the notice shall specify the particular matters in the Division's determination that Prospect seeks to dispute and the basis for the dispute. Matters not identified in the notice of dispute shall be deemed accepted by Prospect. The Division and Prospect shall have thirty (30) calendar days from the receipt by the Division of the notification of dispute to reach an agreement. If agreement cannot be reached on all issues within this thirty (30) day period, the Division shall confirm or modify its decision within an additional fourteen (14) days, and the confirmed or modified decision shall be deemed effective and subject to appeal in accordance with the Act and the Colorado Administrative Procedure Act, Article 4, Title 24, Colorado Revised Statutes.

VIII. NOTICES

66. Unless otherwise specified, any report, notice or other communication required under the Consent Order shall be sent to:

For the Division: Enforcement Unit Supervisor
Colorado Department of Public Health and Environment
APCD-SS-B1-1400
4300 Cherry Creek Drive South
Denver, Colorado 80246-1530

For Prospect: Ward Giltner
Prospect Energy, LLC

1036 Country Club Estates Drive
Castle Rock, Colorado 80108

with a copy to: Jack R. Luellen
Buchalter
1624 Market Street, Suite 400
Denver, Colorado 80202-2457
jluellen@buchlater.com

IX. OBLIGATIONS UNAFFECTED BY BANKRUPTCY

67. The obligations set forth herein are based on the Division's police and regulatory authority. These obligations require specific performance by Prospect of corrective actions intended to prevent on-going or future harm to public health or the environment, or both. Enforcement of these obligations is not stayed by a petition in bankruptcy. Prospect agrees that the penalties set forth in this Consent Order are not in compensation of actual pecuniary loss. Further, the obligations imposed by this Consent Order are necessary for Prospect and the Facility to achieve and maintain compliance with State law.

X. SALES AND TRANSERS OF OPERATIONAL OR OWNERSHIP INTEREST

68. This Consent Order shall not be construed to impede the transfer of an operational interest in, or the operation of, any facility to a third party unaffiliated with Prospect so long as the requirements of this Consent Order are met. This Consent Order shall not be construed to prohibit a contractual allocation as to operational responsibilities only—as between Prospect and a third party—of the burdens of compliance with this Consent Order provided that Prospect and such third party shall remain jointly and severally liable for the obligations of this Consent Order applicable to the transferred or purchased facilities. Prospect shall advise the third party in writing of the existence of this Consent Order prior to such sale or transfer and shall send a copy of such written notification to the Division at least 30 calendar days before the closing date of such proposed sale or transfer.

69. If the Division consents, such consent not to be unreasonably delayed or withheld, and Prospect and the third party buyer comply with all other requirements of this Consent Order, the Division, Prospect and a third party may execute a modification that relieves Prospect of its liability under this Consent Order for, and makes the third party liable for, all obligations and liabilities applicable to the purchased or transferred facility and associated well production assets. Notwithstanding anything herein to the contrary, Prospect may not assign, and may not be released from, any obligation under this Consent Order that is not specific to the purchased or transferred facility.

XI. MODIFICATIONS

70. This Consent Order may be modified only upon the written agreement of the Parties.

XII. TERMINATION

71. Termination by Plugging and Abandonment: Prospect may seek to terminate this Consent Order upon permanent plugging and abandonment of the wells associated with the facilities. To seek termination, Prospect must submit documentation to the Division demonstrating that all wells associated with the facilities have been permanently plugged and abandoned. If the Division determines that termination is appropriate, the Division will issue a notice of termination.

XIII. BINDING EFFECT, AUTHORIZATION TO SIGN, AND EFFECTIVE DATE

72. This Consent Order is binding upon the Parties to this Consent Order and their corporate subsidiaries or parents, their respective officers, directors, agents, attorneys, employees, contractors, successors in interest, affiliates, and assigns. The undersigned warrant that they are authorized to bind legally their respective principals to this Consent Order, and that the Parties have the authority to enter into this Consent Order. This Consent Order shall be effective upon the date signed by the last Party. In the event that a Party does not sign this Consent Order within thirty (30) calendar days of the other Party's signature, this Consent Order becomes null and void. This Consent Order may be executed in multiple counterparts, each of which shall be deemed an original, but all of which shall constitute one and the same Consent Order. The Parties agree that this Consent Order may be electronically signed. The Parties agree that the electronic signatures appearing on this Consent Order are the same as handwritten signatures for the purposes of validity, enforceability, and admissibility.

COLORADO DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

By: DocuSigned by: 47DC47B009A240B... **Date:** 2/15/2024

Shannon McMillan
Compliance and Enforcement Program Manager
Air Pollution Control Division

PROSPECT ENERGY, LLC

DocuSigned by:

By: Ward Giltner
7DD0B21004A74CA...
Ward Giltner

Date: 2/15/2024
Manager

cc: Shannon McMillan, APCD
Jennie Morse, APCD
Craig Giesecke, APCD
Heather Wuollet, APCD
Zack Stazick, APCD
Rebecca Wilson, APCD
Jen Mattox, APCD
Joseph Wright, APCD
Jason Long, APCD
Michael Stovern, EPA (Region VIII)
Will Marshall, Attorney General's Office
David Beckstrom, Attorney General's Office
Sydney McLeod, Larimer County Department of Health and Environment
File

Exhibit 15

nature COMMUNICATIONS

ARTICLE

Check for updates

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Methane emissions from US low production oil and natural gas well sites

Mark Omara[1✉], Daniel Zavala-Araiza[1,2], David R. Lyon[1], Benjamin Hmiel[1], Katherine A. Roberts[1] & Steven P. Hamburg[1]

Eighty percent of US oil and natural gas (O&G) production sites are low production well sites, with average site-level production ≤15 barrels of oil equivalent per day and producing only 6% of the nation's O&G output in 2019. Here, we integrate national site-level O&G production data and previously reported site-level CH_4 measurement data ($n = 240$) and find that low production well sites are a disproportionately large source of US O&G well site CH_4 emissions, emitting more than 4 (95% confidence interval: 3—6) teragrams, 50% more than the total CH_4 emissions from the Permian Basin, one of the world's largest O&G producing regions. We estimate low production well sites represent roughly half (37—75%) of all O&G well site CH_4 emissions, and a production-normalized CH_4 loss rate of more than 10%—a factor of 6—12 times higher than the mean CH_4 loss rate of 1.5% for all O&G well sites in the US. Our work suggests that achieving significant reductions in O&G CH_4 emissions will require mitigation of emissions from low production well sites.

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Mitigation of methane (CH_4) emissions, a powerful greenhouse gas with >80× the 20-year warming potential of carbon dioxide[1,2], is widely recognized as strategically integral to the attainment of the climate-neutrality goals of Paris Agreement[3,4]. In the United States, official estimates from the US Environmental Protection Agency (EPA) indicate nearly one-third (30%) of anthropogenic CH_4 emissions arise from oil and natural gas (O&G) operations[5]. However, a large body of measurement-based studies[6–15] have consistently found higher O&G CH_4 emissions than is estimated in EPA inventories. Alvarez et al.[16] synthesized research on US O&G CH_4 emissions in 2015 and found 13 teragrams (1 Tg = 1 million metric tons), 60% higher than the Greenhouse Gas Inventory (GHGI) estimates for 2015 as estimated in 2017; in Reporting Year 2021, EPA lowered estimated 2015 emissions making the difference 70%[5]. Much of this discrepancy has been attributed to the O&G production sector, where measurement-based estimates are ~2× higher than the GHGI[16–18], with recent research suggesting substantial underestimation in the GHGI attributed to fugitive emissions from well site equipment and unintentional emissions from liquids storage tanks[18].

The US O&G production sector is diverse and complex, with over 800,000 active onshore O&G production wells in 2019[19]. Methane emissions at O&G production well sites—which may have one or multiple wellheads—arise from sources that are common throughout O&G operations (e.g., fugitive emissions from leaking valves and connections and vented emissions from storage tanks and pneumatic devices), in addition to nonroutine sources characterized by excessive, unintentional emissions. Measurement-based studies have generally found weak correlations of CH_4 emissions with site-specific parameters, including O&G production rates, water production, or site age[12,20–22]. However, O&G production declines substantially over the first few years in the life of the well, such that the number of new, high-productivity wells represents a small percentage of the total number of operating wells, where older, low-productivity wells dominate. As a result, production characteristics of US O&G wells are highly skewed: >90% of the nation's O&G production comes from ~20% of wells[19].

Furthermore, a key characteristic of measurement-based O&G site-level CH_4 emissions is the heavy-tailed distributions[8,9,12,13,17,23], where a small fraction of sites is responsible for a disproportionately large fraction of total CH_4 emissions. While the skewness in the distributions of O&G site-level CH_4 emissions and production characteristics are well known, their effect on the national distribution of aggregate CH_4 emissions among low- and high-productivity O&G production sites has received little scrutiny and is much more uncertain.

We define a well site's total O&G production in units of barrels of oil equivalent per day (boed), a single metric representing the site's combined oil (barrels produced) and gas (1 boe = 6 thousand cubic feet, Mcf)[24] production averaged over the well site's total production days in the year. We focus on the low production well site category, where each site has a combined O&G production rate averaged over the year of ≤15 boed[25]. We then use available O&G production data from proprietary sources[19] to assess the regional distribution, O&G production characteristics, and operator profiles for low production sites. Using these data in combination with data on low production well site CH_4 emissions previously collected from a diversity of regions across the United States, we generate a new national estimate of their total CH_4 emissions and assess the significance of these emissions relative to CH_4 emissions from all US O&G production sites. This assessment carries significant policy implications for the effective mitigation of US O&G CH_4 emissions.

Results and discussion

Characteristics of US low production oil and gas well sites. We use the O&G well- and production data from Enverus Prism[19], a commercial platform which collects and aggregates public and proprietary O&G data, to assess the production, age, and operator profiles of low production well sites. We consider each low production site with reported production data as a commercially viable production site or site that routinely produces O&G products that are used for energy consumption. A low production well site may have one or multiple wellheads (average 1.03 wells per site; Methods) with O&G processing equipment that may include separators, dehydrators, pneumatic devices, compressors, flare stacks, and/or hydrocarbon liquids storage vessels[10,18,22]. In 2019, we estimate that 565,000 (3 sf, Methods) low production well sites accounted for 81% of the total number of US active onshore O&G well sites. Yet, they accounted for a substantially smaller share of national oil (5.9%), gas (5.5%), and combined O&G (5.6%) production (Fig. 1).

We classify national low production sites into four cohorts of site-level production rates: (i) >0–2, (ii) 2–5.4, (iii) 5.4–9.7, and (iv) 9.7–15 boed (see Methods, Supplementary Note 6 for further discussion). A majority of low production well sites (57%), 46% of active onshore US O&G well sites, produce very little O&G, ≤2 boed/site, with cumulative production of just 0.7% of total US O&G production, representing 12% of total O&G production from all low production sites. We refer to this subset of low production sites as ultralow production sites and discuss their significance in the following sections.

There is regional diversity in the production characteristics of low production well sites (Fig. 1), with the predominantly gas-producing Appalachian region (Region 1 in Fig. 1) being notable for its large abundance (i.e., 90%, $n = 160{,}000$) of ultralow production well sites (Fig. 1d). Among all low production well sites, these Appalachian ultralow production sites represent 29% of US low production well sites and 5.4% of total O&G production from low production sites (Fig. 1c).

The distribution for site age, defined as the mean number of years in production as of December 2019, shows little variability across regions (Fig. 1e). The mean age for the ultralow production sites is 25 years, only slightly higher than that for sites producing >2 boed/site at 21 years. In general, about 10% of all low production well sites ($n = 73{,}000$) are ≤10 years old (Fig. 1e) with combined O&G production representing 20% of total production from low production well sites, indicative of average declining production with age.

Oil and gas production at newly drilled and completed wells exhibits a rapid rate of decline following initial production. We assessed the production history of over 44,000 single-well low production well sites that were actively producing in 2019 and had their first reported production date in the years between 2012 and 2019. We find that, on average, the initial site-level production for single-well O&G production sites that are vertically drilled is ~20 boed/site, ramping up to ~25 boed/site within the first three months of production, before exponentially declining to below the low production well site productivity threshold of 15 boed within generally 1 to 2 years. For horizontally-drilled wells, we estimate an average initial production of 100 boed/site, with a ramp-up to ~150 boed/site within the first three months and declining to below 15 boed within ~3 to 5 years (Supplementary Note 3). This average boed decline profile for single-well sites suggests continued and rapid growth in the number of future low production well sites, tempered by the rate of growth in the number of newly completed O&G wells and the rate at which operators plug and/or abandon these wells.

There are more than 11,000 O&G operators nationally (Fig. 2a). While a significant proportion (6100 operators, or 52%) own

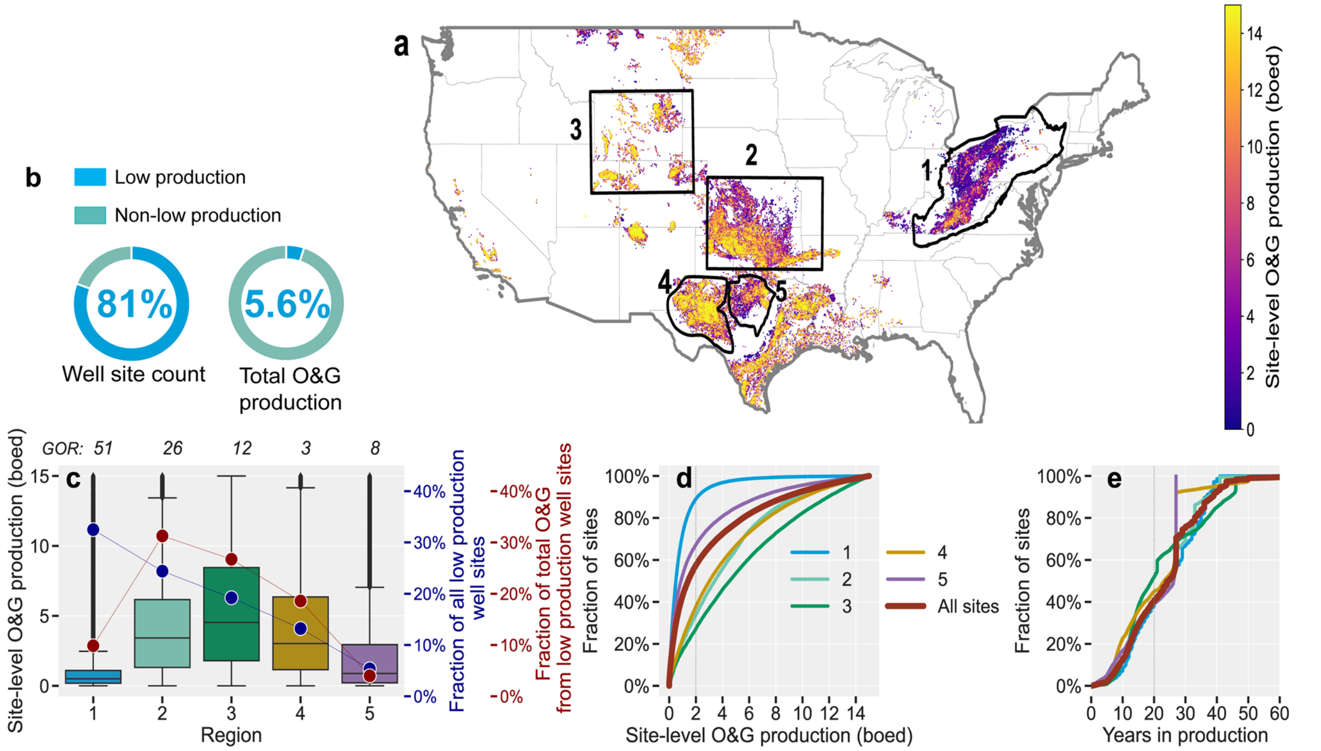

Fig. 1 Characteristics of US low production oil and gas well sites. a Spatial distribution of active onshore low production well sites ($n = 565,000$) color-coded by site-level O&G production in barrels of oil equivalent per day (boed) per site. The numbered boxes show a few of the major low production well site regions, including those for which site-level CH_4 emissions data are available: (1)—Appalachian, (2)—Oklahoma/Kansas/Arkansas, (3)—Colorado/Utah/Wyoming, (4)—Permian Basin, and (5) Barnett Shale. **b** Distribution of the national number of well sites and O&G production, comparing low production sites with non-low production sites. **c** Box plots (centerline, median; box limits, upper and lower quartiles; whiskers, 1.5× interquartile range; points, outliers) showing the distribution of site-level O&G production in each of the five O&G production regions with large numbers of low production well sites shown on the map. The average gas-to-oil ratio (GOR, Mcf/barrel) is shown on the top *x*-axis. These five regions account for three-quarters (76%) and two-thirds (68%) of the total number and O&G production from all low production well sites, respectively. The horizontal lines within each box plot show the median production rate per site. On the right y-axis, the percentage of the total count of low production well sites and total O&G production from all low production well sites are shown in blue and red, respectively. **d** Cumulative distribution functions of site-level O&G production for all low production well sites (red line) and well sites in each of the regions shown on the map (blue line—Region 1, light green—Region 2, dark green—Region 3, orange—Region 4, purple—Region 5). **e** Cumulative distribution functions of low production well site age, representing the years in production as of December 31, 2019 and based on the reported first production date. Lines are color-coded as in **d**. Analysis based on data from Enverus Prism[19] for 2019.

≤5 low production well sites each, the majority of low production well sites (77%) and O&G production (83%) are owned by 770 mid-size to large operators with >100 low production well sites each (Fig. 2b, c). For the ultralow production cohort, these same 770 operators also dominate site count (77%) and O&G production (82%) nationally (Fig. 2b). However, there is regional variability in the ownership profile of the ultralow production sites. For example, while the Appalachian sites (Region 1, Fig. 1) are dominated by operators with >100 well sites each, the Barnett sites (Region 5) are dominated by operators with 11–50 well sites each (Fig. 2b).

Among operators that own 1–50 low production well sites, there are consistent patterns in well site characteristics with the ultralow production sites dominating, but the distribution has a long tail that extends to 15 boed/site (Fig. 2f). This result indicates that small operators own low production well sites with a range of site-level production rates (i.e., not only the ultralow production cohort) and underscores that they do not dominate either the low production well site count or total O&G production from low production well sites.

Methane emissions at low production oil and gas well sites: insights from previous site-level studies. Previous studies indicate CH_4 emissions at low production well sites arise from sources that are common throughout all O&G production operations, including intentionally vented emissions and unintentional emissions from well site equipment such as wellheads, pneumatic devices, separators, dehydrators, compressors, flare stacks, and/or storage vessels[10,18,22]. (Supplementary Fig. 21). At low production well sites, field observations report a common theme revolving around the issue of well site equipment negligence and disrepair[10,22] as the primary driver of CH_4 emissions. Most proximately, recent work by Deighton et al.[22] documents several of these maintenance-related issues, including, for example, (i) leaks at fittings and joints, (ii) leaks and vents from rusted pump jacks, tanks, and other onsite gathering infrastructure, and (iii) evidence of well site neglect or poor maintenance, such as wellheads or casings covered in weeds or fallen trees. In several instances, emissions at low production well sites were reported as “audible”, “visible” or with an “oily smell”, characteristic of emissions sources likely to be effectively resolved via standard leak detection and repair (LDAR) practices, including Audio, Visual, and Olfactory (AVO) inspections.

In this study, we compile and analyze previously published data on site-level CH_4 emissions at low production sites to assess the magnitude and significance of their CH_4 emissions relative to total US O&G production site CH_4 emissions[16]. We focus on

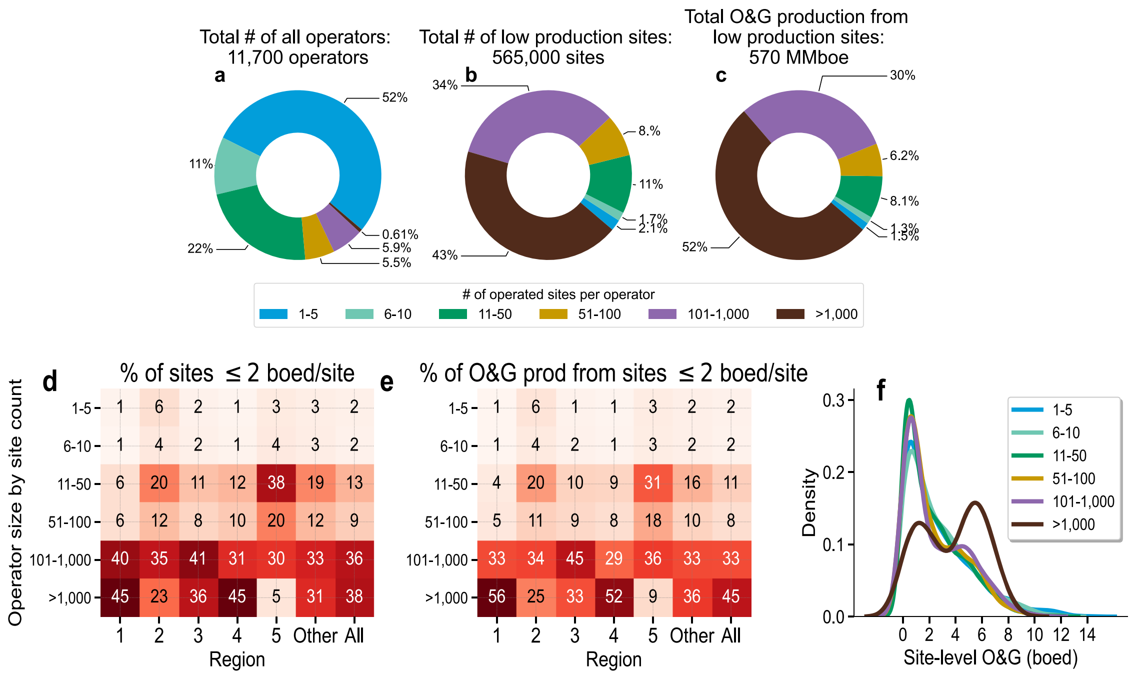

Fig. 2 Low production well site operator profile. a Distribution of the total number of all O&G well site operators. **b** Distribution of the number of operated low production well sites by operator size. **c** Distribution of O&G production for operators with 1–5 (blue), 6–10 (light green), 11–50 (dark green), 51–100 (orange), 101–1,000 (purple), and >1,000 operated sites (dark red). **d** Heatmap showing the distribution of well sites and **e** the distribution of O&G production for only the ultralow production sites (producing ≤2 boed/site) and for each operator category within each region shown in Fig. 1. "Other" means all locations not included in Regions 1–5 in Fig. 1 and "All" indicates national statistics for all ultralow production sites. For example, in Region 1, 1% of ultralow production well sites are owned by operators with 1–5 sites each and, for these sites and operators, their combined production accounts for only 1% of the total. **f** Density plot showing similarities in the distribution of mean site-level O&G production for each operator category. For operators with more than 50 operated well sites, a bimodal distribution or the second cluster of sites producing >2 boed/site emerges. Operator names and data are based on Enverus Prism's[19] aggregation into single operator names, including rolling up subsidiaries to the parent company whenever such information is publicly disclosed.

site-level measurement studies, performed using ground-based downwind measurement approaches[10,12,13,17,20,21] that do not require operator-provided access to measured sites and can resolve total CH_4 emissions at each measured site, but generally do not resolve source-specific emissions (Methods). Our sample of 240 site-level CH_4 emissions data for low production sites is drawn from six independent studies[10,12,13,17,19,20] across six US O&G basins. The most-reported data attributes in these studies are the mean site-level CH_4 emission rates (mass of CH_4 emitted per hour) and site-level O&G production rates. While limited in size relative to the total population of low production sites, these data are drawn from a diversity of O&G production basins and have broadly representative site-level production rates (range: 0.01–15 boed) and CH_4 distribution that support statistically robust estimation of national-scale CH_4 emissions (Methods).

We assess CH_4 emissions at low production sites on the basis of absolute CH_4 emission rates (i.e., the mass of CH_4 emitted per hour) and the production-normalized CH_4 loss rates (i.e., CH_4 emitted relative to CH_4 production)—a useful metric for comparing the degree of CH_4 loss among different production regions or categories of production sites and can reveal the existence of excessive emissions that may result from avoidable abnormal operating conditions[26].

Our synthesis of the 240 site-level CH_4 emission measurements shows a wide range of results, reflecting, in part, the stochastic character of CH_4 emissions at these sites. Most low production well sites (75%) have detectable site-level CH_4 emissions of up to 5 kg CH_4/h (Fig. 3). The unadjusted arithmetic mean CH_4 emission rate is 2.6 kg CH_4/h/site (95% bootstrap confidence interval on the mean: 1.6–4 kg CH_4/h/site) for a weighted-average CH_4 loss rate of 12% of total CH_4 production, assuming an average 80% CH_4 content in produced natural gas[5]. We note that some of the measured sites in the consolidated dataset ($n = 9$) are oil-only sites, with no reported gas production, but with measured CH_4 emissions that range from below the method detection limit (i.e., <0.01 kg CH_4/h/site for tracer flux quantification and <0.036 kg CH_4/h for OTM-33A quantification; see Methods) to 9 kg CH_4/h. The full range of detectable site-level CH_4 emissions at low production well sites are within that for all O&G production sites[16,17] but are more than an order of magnitude higher than measured CH_4 emissions at unplugged abandoned wellheads[27,28].

The empirical distribution of absolute CH_4 emission rates indicates that the top 5% of high-emitting sites are responsible for ~50% of cumulative emissions (Methods), with each site emitting >7.3 kg CH_4/h. The data suggest an increased likelihood of high CH_4 emission potential for low production well sites producing >~2 boed/site (Fig. 3b). Skewed CH_4 emissions distributions have been observed consistently across the O&G supply chain[8,9,12,13,17,23,29]. Although they have stochastic and low-probability occurrence at any one site[8], the significant influence of high-emitting sites is well-documented and is postulated as the primary driver for the observed discrepancy between inventory/bottom-up component-level methods and site-level measurement-based estimates[16].

For low production well sites, we also observe a second dimension to the skewness in the CH_4 emissions distribution: among sites with reported gas production, the top 15% of sites based on CH_4 loss rates, emit >32% of their CH_4 production, while the top 5% exhibit CH_4 loss rates of >90%. Furthermore,

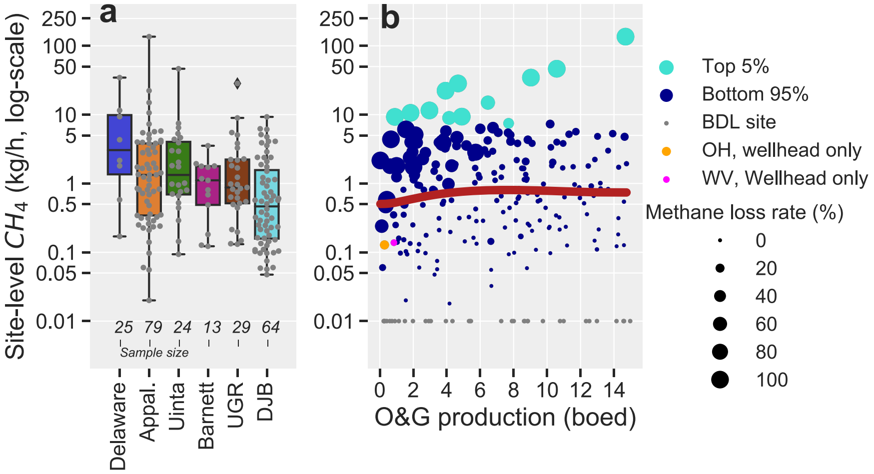

Fig. 3 Low production well site CH_4 emissions data as reported in previous studies. a CH_4 emissions data for six basins with at least $n > 5$ observations shown as box plots (centerline, median; box limits, upper and lower quartiles; whiskers, 1.5× interquartile range) and individual points (gray circles). Sample sizes are shown at the bottom of the plot. Only site-level measurements above method detection limits of 0.01–0.036 kg/h are shown. Appal.—Appalachian (Pennsylvania, Ohio, West Virginia); Delaware (Texas/New Mexico); Barnett (Texas); Uinta (Utah); UGR—Upper Green River (Wyoming); DJB—Denver-Julesburg Basin (Colorado). Low production well site data were a subset of site-level measurements reported by: Robertson et al[13]., Robertson et al[21]., Caulton et al[12]., Omara et al[10]., Omara et al[17]. and Brantley et al[20]. **b** Relationship between measured site-level CH_4 emissions and O&G production in barrels of oil equivalent per day (boed). The plot shows the top 5% of high-emitting sites ($n = 12$, green symbols), the bottom 95% of sites ($n = 192$, blue symbols), and below-detection-limit (BDL) sites ($n = 36$, gray symbols). Each site's CH_4 loss rate is indicated by the size of the circles. Oil-only sites or sites with reported CH_4 loss rates >100% are assigned values of 100%. The orange and pink symbols represent the mean wellhead-only CH_4 and O&G production for low production sites sampled in Ohio[22] and West Virginia[31]. Data from these two studies were not used in emission models because they exclude other sources such as tanks and separators, but are shown here to illustrate that wellhead-only CH_4 emissions can be significant even at low production well sites. The solid-dark red line shows the nonparametric Bayesian regression model for the bottom 95% of sites (see Methods).

there is a tendency toward higher CH_4 loss rates as site-level O&G production declines (Fig. 3b), consistent with previous observations for well sites[16,17] and natural gas production regions[30]. Indeed, two recent studies focused on CH_4 emission characterization at the wellhead exclusive of other site-specific sources (e.g., storage tanks and separators) reported mean CH_4 loss rates of 8.8% (for sites producing ~0–3 boed)[31] and 21% (for sites producing <1 boed)[22] of CH_4 production in West Virginia and Ohio, respectively, showing the significant CH_4 emissions that can occur even from a single source, i.e., wellheads, at low production well sites (Supplementary Fig. 24).

By modeling the temporal evolution of site-level emissions, Cardoso-Saldana and Allen[32] attributes these increasing proportional losses to the interplay between emission sources that are production-dependent and decline rapidly with declines in production (e.g., condensate flashing) and those that are production-independent (e.g., fugitive leaks and venting from pneumatic devices). As site-level production declines over time, there is a substantial increase in the relative contribution of production-independent emission sources, resulting in higher CH_4 loss rates. Assuming the empirical distribution of CH_4 loss rates characterized among the 240 measured sites is representative of national patterns, the data suggest a small fraction of low production well sites (5% or $n = 28{,}000$) are not just high-emitting (on a mass basis), but "functionally super-emitting"[26] with extremely high CH_4 loss rates indicative of the existence of avoidable abnormal process operating conditions (e.g., malfunctioning processing equipment).

Further evidence for extremely high, but low-frequency CH_4 emissions at low production well sites can be found in recent work by Cusworth et al.[33] which used an aerial screening approach to identify and characterize the persistence of large (>10–20 kg/h) CH_4 sources in the Permian Basin. We spatially linked, and visually confirmed in satellite imagery, the location of their detected CH_4 plumes to 62 unique low production well site sources within the Permian Basin (Supplementary Note 7). Measured CH_4 emissions at these predominantly oil-production sites ranged from ~50–800 kg CH_4/h, with their cumulative CH_4 emissions far exceeding their reported total CH_4 production by a factor of 30× (see discussion in Supplementary Note 7). While we estimate a very low prevalence rate (~0.05% in the Permian Basin; Supplementary Note 7) for such abnormally high CH_4 emissions among the Permian low production well sites, their existence nevertheless underscores the significant CH_4 waste potential as well as the CH_4 mitigation opportunities at low production well sites.

The stochasticity in the site-level CH_4 emission characteristics[8,22] likely explains, in part, the observed variability in the empirical distribution of basin-level CH_4 emissions (Fig. 3a). Other factors such as operator-specific practices, including voluntary or mandated O&G emission reduction programs, could contribute to observed variability, although these are difficult to quantify with available data. Overall, from the ensemble of basin-level data with $n > 25$ observations, we find statistical similarities in the empirical distribution of site-level absolute CH_4 emissions among measured low production well sites in the Appalachian, Upper Green River, and Denver-Julesburg basins (Methods). This statistical similarity supports our consolidation of data from a diverse set of O&G basins to assess the total CH_4 emissions attributable to the national population of low production well sites.

National estimate of low production well site methane emissions. Our assessment of national-level CH_4 emissions from low production sites leverages the broadly representative distribution of site-level production and statistical similarities in basin-scale empirical CH_4 distributions (see Methods) in our consolidated sample of measurement-based site-level data ($n = 240$). We use these data in a hybrid nonparametric Bayesian regression and Monte Carlo model to separately assess the emissions contribution of the top 5% of sites based on absolute CH_4 emissions (green symbols in Fig. 3b), the bottom 95% of sites (blue symbols in Fig. 3b) and the influence of below-detection-limit sites (gray symbols in Fig. 3b, Methods). For the high-emitting sites, we develop frequency and emissions distributions based on random nonparametric bootstrap resampling. For the bottom 95% of sites with detectable emissions, we develop site-level emission factors based on a nonparametric Bayesian regression model (solid-dark red line in Fig. 3b) of the site-level CH_4 emissions as functions of site-level O&G production. This approach accounts for the empirically observed relative independence of site-level CH_4 emissions with O&G production for sites producing ~>2–4 boed/site and an apparent declining trend in absolute site-level CH_4 emissions for the ultralow production sites (Supplementary Fig. 15). Finally, we develop a frequency distribution for the below-detection-limit sites and use this distribution to decrement the modeled site-level CH_4 emissions for the bottom 95% of sites (Methods).

Our estimate for total CH_4 emissions from active onshore low production O&G well sites in 2019 is 4 Tg (1 s.f.), with a 95% confidence interval (CI) on the mean of 3–6 Tg (Fig. 4a). The mean estimate is 54% (95% CI: 37–75%) of the 7.6 Tg for total O&G CH_4 emissions from all O&G production sites based on Alvarez et al.[16], which we consider the best current measurement-based estimate of national-scale CH_4 emissions from all US O&G production sites. Our measurement-based estimate for all US low production well sites is roughly 50% more than the total CH_4 emissions from the entire Permian Basin (2.7 Tg)[14], one of the world's largest O&G producing regions. Additionally, the 4 Tg of low production well site CH_4 emissions is >10% greater than the US EPA's estimate of ~3.4 Tg for all US O&G production site CH_4 emissions in 2019[5]. These CH_4 emissions are equivalent to CH_4 loss rates of 13% (95% CI: 8–17%) relative to CH_4 production in 2019, assuming 80% CH_4 content in produced natural gas. This CH_4 loss rate is a factor of 6–12 times higher than the mean CH_4 loss rate of 1.5% for all O&G well sites based on Alvarez et al.[16] (Fig. 4a).

We estimate that ~50% (95% CI: 20–80%) of low production well site CH_4 emissions are from the top 5% of sites that emit >7 kg CH_4/h/site, consistent with the empirical distribution and with previous results from a large body of O&G CH_4 studies[8,9,12,17,23,26,29,33]. Overall, our modeling indicates that 90% of low production well sites emit an average of <1 kg CH_4/h/site, while 50% emit >10% of their CH_4 production (Fig. 4c). Based on a total of 4 Tg CH_4 emitted by 565,000 low production well sites in 2019, we estimate an average site-level CH_4 emission rate of 0.8 kg/h/site (95% CI: 0.5–1.2). This site-level estimate for low production well sites is approximately 50% lower than the mean site-level CH_4 emission rates for all US natural gas production sites (1.7 kg CH_4/h/site[17]). Thus, while mean low production well site emissions are lower than that for all O&G production sites on an absolute basis, their production-normalized CH_4 loss rates are significantly higher, consistent with previous assessments focused on CH_4 emissions from US natural gas production sites[17].

We find that the ultralow production cohort accounts for 25% (95% CI: 17–49%) of total low production site CH_4 emissions (Fig. 4a), representing ~10% of total US O&G CH_4 emissions from production sites and only 0.7% of US O&G production. In addition, the Appalachian region dominates regional CH_4 emissions, with an estimated total of 1.2 Tg (95% CI: 0.8–1.9; Fig. 4b). We estimate the ultralow production sites (i.e., sites ≤2 boed) in the Appalachian account for ~one-half (95% CI: 40–60%) of the region's total low production well site CH_4 emissions, where the estimated regional CH_4 loss rate is 26% (95% CI: 17–40%; Fig. 4b). These results underscore the significance of the ultralow production sites as sources of O&G CH_4 emissions, especially in the Appalachian region where they account for ~90% of all low production sites.

Policy implications. Eighty percent of all US O&G production sites are low production sites, yet they produce only 6% of the nation's O&G output. Even as their production declines over time, CH_4 emissions at low production well sites continue from both routine and nonroutine, but avoidable, sources. Low production well sites are abundant and their cumulative CH_4 emissions are significant: they account for about one-half (95% CI: 37–75%) of US O&G production site CH_4 emissions. The site-level CH_4 distribution among these sites is highly skewed, with a small fraction (5%) responsible for a large proportion (~50%) of their total emissions and, on average, CH_4 losses occur at high

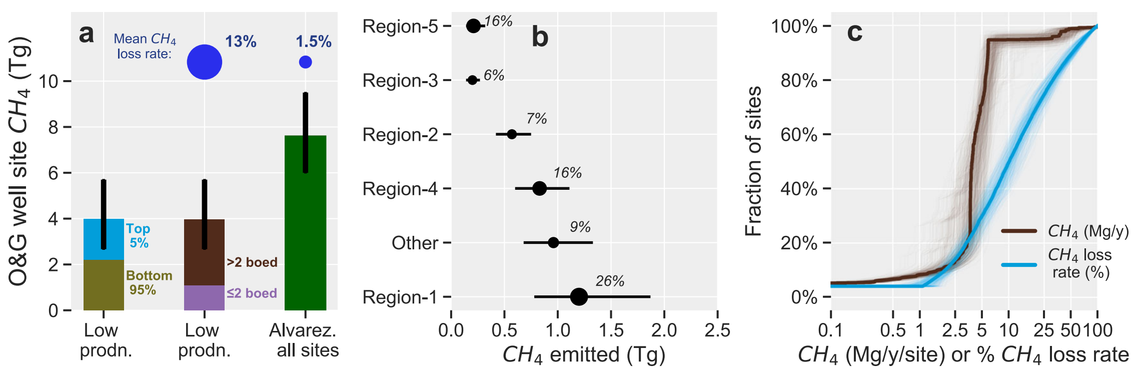

Fig. 4 National estimate of low production well site CH_4 emissions. a Comparison with Alvarez et al.[16] assessment of total national CH_4 emissions from all O&G production sites (Low prodn. = low production sites). Error bars represent the 95% confidence intervals (Methods). The blue bubbles represent the production-normalized CH_4 loss rates for low production well sites (this study) and for all O&G sites[16]. **b** Regional estimates of low production well site CH_4 emissions (see Fig. 1), with error bars representing the 95% confidence intervals on the mean (Methods). "Other" means total estimates for sites in other locations outside of regions 1–5 in Fig. 1. Symbols are sized by CH_4 loss rates relative to gross CH_4 production in each region, which are shown as % against each symbol. **c** Modeled distribution of mean site-level CH_4 emissions (brown lines) and CH_4 loss rates (blue lines). The thick solid lines represent the mean distribution while the thin lines are the results of the 500 simulated distributions for uncertainty assessment (Methods). For visualization, results are shown for the 99% of sites with modeled site-level emissions of up to 100 Mg/year and 100% CH_4 loss rates. Additional results in tabular form can be found in Supplementary Tables 5–7. 1 Mg = 1000 kg.

rates exceeding 10% of site-level CH_4 production. Identifying high-emitting sites and uncovering the root causes of excessive emissions is key to mitigating CH_4 emissions from low production well sites, as is recognizing the disproportionately large role that low producing sites play in contributing to CH_4 emissions in the United States.

Field-based observations[10,22] point to avoidable maintenance-related issues as a key driver of CH_4 emissions at low production well sites, particularly at older sites that tend to suffer from prolonged lack of attention from their owners or operators. The commonly observed sources of CH_4 emissions at these sites, coupled with the stochastic character of high-emission events, suggest routine emissions monitoring and repair has the potential to yield large emission reduction benefits. Ravikumar et al.[34] report that a single LDAR survey reduced site-level emissions by 44% at O&G sites generally, concluding that effective leak mitigation will require frequent surveys utilizing low-cost, rapidly deployable leak detection technologies, such as cheap fixed sensors and fence-line truck-based monitoring. Assuming applicability to low production well sites here, a 44% LDAR effectiveness implies reductions of almost 2 Tg in CH_4 emissions after one survey, equivalent to a 24% reduction in total O&G CH_4 emissions from all US O&G well sites.

Currently, there is no direct regulation of CH_4 emissions from existing low production well sites at the federal level (see Supplementary Table 5 for a summary of state regulatory actions), although the US EPA has recently proposed new regulations that would require quarterly monitoring and repair of CH_4 leaks at all well sites that have a potential to emit CH_4 emissions >3 metric tons per year as calculated based on bottom-up inventory approaches[35]. Current bottom-up inventory estimates of potential site-level CH_4 emissions can underestimate actual emissions, for example, by not adequately accounting for higher emissions due to malfunctions[36]. Our assessment not only underscores the significant contribution of low production well sites to total CH_4 from O&G production operations but also supports the inclusion of low production well sites as part of any effective mitigation strategy for O&G CH_4 emissions.

As mentioned, routine fugitive emissions monitoring and repair programs inclusive of storage tank fugitives[34,37,38] can be especially effective at these sites, as is mitigating vented emissions, for example, through replacement of high- and low-bleed pneumatic devices with zero-bleed alternatives. The ultralow production cohort of ≤2 boed/site represents a unique challenge given its large size, limited economic value, and proportionally high CH_4 emission rates. State and federal policymakers must consider whether and how these well sites can be operated economically while minimizing CH_4 emissions, and if they cannot be, how to finance their proper plugging and abandonment.

Current economic support for low production well site owners includes programs from the Internal Revenue Service and several states that incentivize low production well site operations through tax credits that kick in when commodity prices drop below a predetermined threshold[39]. The goals for these programs are to support continued low production well site operation as an alternative to shutting in wells in a low-price environment, but inadvertently incentivize continued emissions of CH_4 and other harmful air pollutants linked to O&G operations. Thus, the role of low production well sites needs to be reassessed in light of their outsized importance relative to CH_4 emissions from the O&G sector and related mitigation opportunities. As part of this, there is a need for more measurement-based data and a more comprehensive look at the externalities of these low production sites, owned by over 10,000 individuals and small corporations nationally.

Methods

Well site O&G data. We use the monthly O&G well-level and production data available from Enverus Prism[19], aggregating monthly production data for 2019 and deriving average well-level production rates (barrels of oil equivalent per day, boed) based on the reported number of production days (Supplementary Note 1). We use the monthly production data as is, acknowledging there may be uncertainty in the data that are difficult to quantify, for example, due to reporting errors. We filtered the well-level data for active onshore wells ($n = 842{,}978$) and used geospatial clustering approaches to derive well site attributes (i.e., site-level O&G production rates) from well-level data, assuming wells on the same site are clustered within r buffer radius, where $r = 25$ and 50 m for vertically-drilled and horizontally-drilled wells, respectively (Supplementary Note 1). Based on this approach, we estimate the total number of active onshore low production well sites at 565,000 sites, with an uncertainty of +2/−5% based on a sensitivity assessment of various choices of buffer radii (Supplementary Note 1). The average number of wells per site is 1.03, 1.9, and 1.2 for low production, non-low production, and all O&G well sites, respectively.

We assess the distribution of site-level O&G production by first classifying the data into four O&G production cohorts based on natural breaks in the data as assessed via the Jenks optimization method. The four cohorts are: (i) >0–2, (ii) 2–5.4, (iii) 5.4–9.7, and (iv) 9.7–15 boed (see Supplementary Note 6 for further discussion).

Low production well site methane emissions data. Methane emissions measurements at O&G well sites have typically been performed using either onsite, equipment- or component-level measurement approaches or offsite, downwind measurements. In the former, each potentially CH_4 emitting component (e.g., valves, flanges, fittings, etc) is screened and their emissions measured and aggregated to provide an estimate of total site-level emissions. In the latter, CH_4 plume concentrations emitted from the O&G well site are taken at an appropriate downwind location using near-real-time concentration measurement instruments; emission rates are then estimated by accounting for the dynamics of plume transport from the source to the measurement point. Some offsite measurement-based studies have used chemical tracers released at known flow rates in close proximity to the known emission source[10] to quantify the CH_4 emission rate without the need for plume transport models, which are typically based on Gaussian plume dispersion theory[12,13,20].

Previous studies vary in geography and scope; while some focused on low production well sites, others measured low production well sites as part of a larger measurement campaign that also included non-low production well sites. We assessed each relevant, previously published, peer-reviewed study for CH_4 measurement data and selected data for low production well site CH_4 emissions based on the following criteria:

(i) The measurements were focused on quantifying total site-level CH_4 emissions,
(ii) Measurements captured both low and high-emitting sites, and
(iii) Both oil and gas production data were reported for each site where they could be obtained (e.g., based on proprietary data, state-level reports or other reported attributes such as the location of the measured site and date of measurement).

Based on the above criteria, we selected 240 site-level measurement data for low production well sites, with 230 measurements taken from studies by Brantley et al.[20], Omara et al.[10], Robertson et al.[21], Omara et al.[17], Caulton et al.[12], and Robertson et al.[13]. We also include ten new low production well site CH_4 measurement data in the Delaware sub-basin of the Permian Basin, based on OTM-33A measurements conducted in January 2020 by the same team that previously reported on site-level CH_4 emissions data in this region (Robertson et al.[13]) as part of Environmental Defense Fund's PermianMAP campaign[40]. These datasets are included in Supplementary Data 1. One of the limitations of the ground-based downwind site-level measurement approaches is that the quantification of onsite equipment-level emissions is generally not possible. However, these methods do not require operator-provided access and the site-level data we use herein were obtained without advance operator knowledge.

Each study reported an average measured site-level CH_4 emission rate, in addition to O&G production for the month of measurement. Most studies did not report the drilling trajectory for the sampled well sites. However, based on our review of metadata available in a few of the studies[10,12,17,40], we identified 84 vertically-drilled well sites, three horizontally-drilled well sites, and three directionally-drilled well sites. We use the reported data as is, including emissions data that were reported as zeros or below the method detection limits (BDL, 0.036 kg CH_4/h for OTM-33A/Gaussian dispersion modeling approaches[20,21] and 0.01 kg CH_4/h for tracer flux quantification[10]). For studies that did not report production-normalized CH_4 emission rates[12,13,20,21], we compute the CH_4 loss rates based on the reported gas production rate and assume an average CH_4 content in natural gas of 80% CH_4[5]. Additional information on these datasets is provided in Supplementary Note 4.

Analysis of low production well site methane emissions data. We begin our assessment by characterizing the representativeness of the measured site-level data relative to the national population of low production well sites. Given the available data attributes (i.e., site-level emission and production rates), we focus our assessment on (i) geographical diversity, (ii) distribution of site-level production rates, and (iii) distribution of site-level CH_4 emissions. Our consolidated sample represents broad spatial coverage as indicated by measurements performed in six major O&G producing regions, including the Appalachian, Uinta, Denver-Julesburg, Upper Green River, Barnett, and the Permian regions (Supplementary Fig. 18). The average gas-to-oil ratio (GOR) for low production sites in these basins ranges from 4 Mcf/barrel to 88 Mcf/barrel, well within the national average of 20 Mcf/barrel. Additionally, all O&G production cohorts (i.e., <2, 2–5.4, 5.4–9.7, and 9.7–15 boed) are represented in the measurement data, where reported site-level production data range from 0.01 to 15 boed. However, the overall production distribution for the measurement sites indicates an oversampling of well sites producing >~5 boed when compared with the distribution for all low production sites nationally (Supplementary Fig. 20). Our emissions modeling approach (described below) accounts for this production distribution as we do not want to bias the modeled CH_4 emission rates.

Because the emissions datasets are based on measurements in several basins with unique production and other operational characteristics, we assess whether the emissions distributions from specific basins are statistically similar enough to justify combining the datasets for purposes of estimating national-scale emissions. We assess statistical similarities in site-level CH_4 emissions distributions using the Kolmogorov–Smirnov two-sample test, limiting our basin-basin comparison to those basins with $n > 25$ observations, with significance established at $p < 1\%$. This assessment included sites in the Denver-Julesburg ($n = 64$), Upper Green River ($n = 29$), and the Appalachian ($n = 79$) basins. Among these basins, we find statistical similarities and considerable overlap in the empirical site-level CH_4 emission distributions (Supplementary Fig. 21 and Supplementary Table 4).

To extrapolate measured site-level CH_4 emissions to the total population of sites, we develop a hybrid Monte-Carlo and nonparametric Bayesian regression modeling approach to account for the skewed characteristics of the site-level CH_4 data and the influence of the below-detection-limit sites. We begin by reconstructing the empirical distribution of the consolidated dataset via a random bootstrapping procedure, from which we simulate the frequency of finding a below-detection limit (BDL) site and a high-emitting site if the sites were randomly sampled, with replacement, 10^4 times.

We define high-emitting sites as sites that account for the top 5% of total CH_4 emissions. The nonparametric bootstrapping procedure indicates that their percent contribution to total CH_4 emissions (η_{high}) varies from ~20 to 75%, with the 50th percentile of ~50% (Fig. 5a), reflecting uncertainty resulting from a relatively small sample size. For each resampled distribution, we compute the frequency of finding a high-emitting site (f_{high}), whose absolute emissions exceed 7.3 kg CH_4/h (i.e., the minimum emission rate for the top 5% of sites). We follow a similar procedure to create an emission distribution for the site-level CH_4 emission rate for the top 5% of sites, applying resampling weights $1/w_i$to each high-emission rate, where w_i is the relative contribution of high-emitter i to the total CH_4 emissions. In addition, with each nonparametric bootstrap sample, we compute the frequency of finding a site with emissions that are below the detection limit of the measurement methods (reported as zeros). The frequency distribution for BDL sites (f_{BDL}) is shown in Fig. 5c and the distribution for the central estimates of high-emitter emission rates is shown in Fig. 5d.

For the bottom 95% of sites with detected emissions above the detection limit, we apply a nonparametric Bayesian regression model to estimate the mean CH_4 emission rates as functions of site-level O&G production. This approach accounts for the potential bias due to oversampling of the higher end of the site-level production distribution (Supplementary Fig. 20) as well as the empirically observed emission trends that are weakly dependent on site-level production (Fig. 3b). We apply a log-transformation to the site-level emissions data and model the distribution assuming a univariate normal likelihood with mean μ and standard deviation σ. We model μ as a linear model with a y-intercept α and a spline basis ω, based on a design matrix incorporating a cubic B-spline with $n = 3$ knots (set at 2 boed—beyond which most high-emitters are observed—and at a minimum and maximum boed of 3×10^{-3} and 14.97 boed, respectively). We apply relatively weak priors for $\alpha \sim N(0.1, 0.5)$, $\omega \sim N(-1, 1)$ and $\sigma \sim \mathrm{Exp}(1)$. For Bayesian inference, we draw 5000 posterior samples from the posterior distribution using the PyMC3[41] implementation of the No-U-Turn Sampler (NUTS)[42] algorithm, resulting in $\alpha = 0.38$ (94% highest posterior density interval: −0.25, 1) and $\sigma = 1.3$ (94% HPD interval: 1.2, 1.5). We use these posterior results to generate predictions of the mean site-level CH_4 emissions as functions of O&G production for the bottom 95% of sites, which are shown as a solid-dark red line in Fig. 3b. Additional results and discussion for the nonparametric Bayesian modeling procedure are found in Supplementary Note 5.

We then proceed as follows in extrapolating site-level CH_4 emissions to the total population of low production well sites ($m = 565{,}000$ sites). We randomly sample a frequency (f_{high}) of high-emitters from the frequency distribution for the top 5% of high-emitting sites based on absolute CH_4 emissions (Fig. 5b). We use f_{high} to compute the total number of sites (n_1) that are high-emitting at any one time, restricting our selection to sites with site-level O&G production >2 boed/site beyond which most high-emitters are observed (Fig. 3b). For each high-emitting site, we apply a randomly selected CH_4 emission rate from the modeled distribution of high-emitter CH_4 emissions (central estimates shown in Fig. 5d). The remaining sites ($n_2 = m - n_1$) are the bottom 95% of sites, for which we apply a mean CH_4 emission rate to each site based on the binning of the posterior predictions from the Bayesian nonparametric regression into 192 discrete production (boed) cohorts. The predictions for the mean CH_4 emission rate for each site in the bottom 95% of sites are randomly drawn 500 times from the results of the posterior distributions. As some sites can have below-detection-limit emissions, we decrement the mean emission rate for each site based on a randomly sampled frequency of BDL sites (f_{BDL}). For all m low production well sites, we repeat this procedure 500 times and develop a distribution of total CH_4 emissions for (i) the top 5% of sites, (ii) the bottom 95% of sites, and (iii) total CH_4 emissions for all sites, accounting for the contribution for the top 5% of sites based on the results of the 10^4 Lorenz curves generated in Fig. 5a (η_{high})(Supplementary Note 5 and Supplementary Figs. 14, 22, 23). Each site's modeled CH_4 emissions is multiplied by the total number of reported production days (Supplementary Note 1) to estimate the annual total CH_4 emissions.

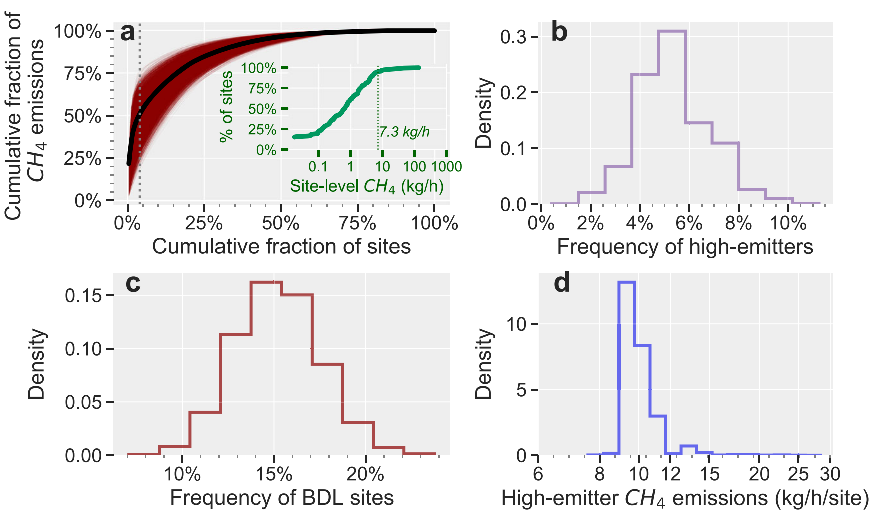

Fig. 5 Site-level CH_4 emission data for low production well sites. a Lorenz curve showing the cumulative fraction of absolute CH_4 emissions as functions of cumulative fraction of sites. The top 5% of sites (dashed vertical line) account for ~50% of total CH_4 emissions. The shaded dark red area shows the 10^4 Lorenz curves derived via a nonparametric bootstrapping of the empirical data, from which the contribution of the top 5% of sites to the total CH_4 emissions are obtained (η_{high}, see Supplementary Fig. 22). Inset is the cumulative distribution function for site-level CH_4 emissions, with a dashed vertical line showing the emission rate threshold for the top 5% of high-emitting sites. **b** Histogram of the frequency of finding a high-emitting site based on 10^4 random bootstrap samples of the empirical data. **c** Histogram of the frequency of below-detection-limit sites. **d** Histogram of the central estimates of high-emitter CH_4 leakage rates.

We also assess the same site-level data with a second statistical model that is independent of site-level production rates, following the approach by Zavala-Araiza et al.[7] and assuming the underlying distribution of the site-level CH_4 emissions as lognormal. For this assessment, we develop CH_4 emissions factors of 3.2 kg CH_4/h/site (95% CI: 0.8–18; Supplementary Note 6). The overall results are higher but within 95% confidence intervals of our primary model estimates, which more comprehensively assesses the distribution of emissions relative to the emitter characteristics of the high-emitting sites (top 5% of sites), the bottom 95% of sites with detectable emissions and the below-detection-limit sites.

Uncertainty assessment. While available site-level CH_4 emissions data are sufficient to derive statistically robust national estimates, we acknowledge the limited sample size ($n = 240$) likely increases uncertainty in our assessment. This uncertainty is driven by variability in measured site-level CH_4 emissions, which in turn determines the observed distribution of emissions given the sample size and distribution of site-level production rates. Variability in site-level CH_4 emissions distributions might be reasonably expected if more samples were available. Our emissions models for the top 5% of high-emitting sites, the bottom 95% of sites and the BDL sites are based on probabilistic models from which we assess the full range of likely frequency and emissions distributions conditional on the observations (Fig. 5). As described, the mean CH_4 emission rate from each of the 565,000 low production site is estimated 500 times in an iterative emissions modeling scheme where both the inputs and outputs are probability distributions reflecting inherent uncertainty in the empirical data. We compute the 95% confidence intervals on our estimates based on the 2.5th and the 97.5th percentiles of the modeled probability distributions for the estimated mean total CH_4 emissions. We estimate the mean and 95% confidence intervals on the mean as 2 (1.6–3) Tg and 2 (0.8–3.3) Tg for the bottom 95% and top 5% of sites, respectively. For all low production sites, the combined CH_4 distribution has a mean and 95% confidence interval of 4 (3–6) Tg (1 s.f.) as shown in Fig. 4a (see Supplementary Fig. 23 and Supplementary Tables 5–7 for additional details).

Data availability

All site-level CH_4 emission rate data used in this study are included in Supplemental Dataset 1. The national well-level O&G production data comes from Enverus, an O&G software company. Due to its proprietary nature, the data cannot be made openly available. Further information about the data and conditions for access are available at www.enverus.com.

Code availability

Python 3.7 code used for the data analysis and visualization are available from the authors upon request.

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Author contributions
M.O. and S.P.H. conceptualized the study. Formal analysis and visualization were performed by M.O., with contributions to data analysis and interpretation by D.Z.-A., D.R.L., B.H., K.A.R., and S.P.H. M.O. wrote the manuscript with contributions from all co-authors.

Competing interests
The authors declare no competing interests.

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