COLORADO REGULATION 7

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ABSTRACT

The newly adopted Colorado Regulation 7 – Control of Ozone via Ozone Precursors and Control of Hydrocarbon via Oil and Gas Emissions, will have wide-spread impact on well production facilities and compressor stations in the State of Colorado. This regulation is being tracked by the US Environmental Protection Agency (EPA) and neighboring states. It is quite possible that other states may use the Colorado program as a framework for the oil and gas sector. The final rule includes monitoring of methane and ethane, as well as volatile organic compounds (VOCs) emissions. This paper will present case studies using existing data of relevant facility leak detection and repair (LDAR) programs to explore expected leak rates following implementation of an LDAR program, and long-term leak rate trends. Colorado Regulation 7 monitoring frequencies and fugitive emission factors are explored along with how these factors will impact uncontrolled actual emissions calculations.

INTRODUCTION

In February 2014, the Colorado Air Quality Control Commission adopted several significant changes to air regulations implemented by the Colorado Department of Public Health and Environment (CDPHE), Air Pollution Control Division affecting the oil and gas industry. Changes were made to Colorado Regulation 3 affecting emission inventories and permitting, and Regulation 6 with the full adoption of New Source Performance Standards Subpart OOOO. However, the most significant rulemaking was the adoption of changes to Colorado Regulation 7 – Control of Ozone via Ozone Precursors and Control of Hydrocarbon via Oil and Gas Emissions. The most significant impact of this new regulation is at well production facilities and compressor stations. Historically these facilities have been exempt from LDAR requirements. The LDAR monitoring frequency written into Colorado Regulation 7 is unprecedented in comparison to any other Federal regulations, and they do not provide any allowance to transfer into a less frequent monitoring schedule based on good performance (skip

period, or “step down” monitoring). The emission factors used in Colorado Regulation 7 were adopted from EPA’s Protocol for Equipment Leak Emission Estimates, 435/R-95-017, November 1995 (hereinafter referred to as “EPA Protocol”). These emission factors are based on a 10,000 ppm leak rate and reflect studies conducted in the 1980s. Two key objectives of the study presented herein are: 1) evaluating the leak frequencies at facilities under active LDAR programs comparable to Colorado Regulation 7 definitions of well production facilities and compressor stations; and 2) exploring the impact of the emission calculations and the absence of skip period monitoring options in the new Colorado Regulation 7 at these never-before-monitored well production facilities and compressor stations.

METHODOLOGY

Of all the processing units in a natural gas processing plant, the equipment and throughput in the inlet processing unit (IPU) most closely resembles the equipment and throughput at oil and gas well production facilities. The IPU is the initial treating unit in a natural gas processing plant and consists of a feed gas receiving system and a condensate separation system. Equipment common between IPUs and well production facilities include feed gas heaters, separators, compressors, and glycol dehydrators. The feed to the IPU consists of field gas (natural gas prior to treatment), hydrocarbon liquids, aqueous liquids, acidic gases, and entrained solids. The feed gas can contain up to 80 percent methane, and overall, is generally similar to the types of materials found in well production facilities. Because of these similarities, monitoring information on the equipment in IPUs provides an excellent dataset for determining expected leak rates for well production facilities and compressor stations defined in Colorado Regulation 7 (Section XVII.A.17).

Fourteen natural gas processing plants with new and established LDAR programs located in Colorado, Wyoming, North Dakota, Oklahoma, and Texas were selected for this study. All inspections included in the dataset were conducted in accordance with New Source Performance Standard (NSPS) Subpart KKK - Standards of Performance for Equipment Leaks of Volatile Organic Compounds (VOCs) From Onshore Natural Gas Processing Plants. All inspection data underwent thorough weekly and monthly QA/QC reviews, including facility data queries, to determine that all required inspections were complete, component counts were accurate, repairs were timely, and technician pace was reasonable for Method 21 monitoring.

Although all of the same component types exist at both well production facilities and IPUs, the dataset was further refined to include only valves that were classified as normal to monitor (NTM) in

accordance with EPA's Method 21 monitoring protocol. The study was limited to NTM valves for two reasons: 1) valves generally show the highest leak frequency, and therefore the highest emissions of all component types; and 2) to avoid the complexity of multiple monitoring frequency schedules for multiple component types. All valves were initially monitored over two successive months with passing inspections of less than 10,000 ppm before skipping to a quarterly monitoring schedule as allowed in NSPS Subpart KKK.

The monitoring and leak frequencies for these NTM valves in the fourteen inlet process units were divided into two case studies based on data availability and reliability.

- Case Study 1 – This study focused on leak frequencies at facilities following the initial implementation of an LDAR program. This study evaluated the initial and subsequent leak rates in the year following implementation.
- Case Study 2 – This study evaluated leak frequency sustainability over a three-year period at facilities with an established, long-term LDAR program.

RESULTS

Case Study 1 evaluated valve monitoring data collected in the IPU at eight natural gas processing facilities. These eight facilities were either newly constructed or modified natural gas processing plants, and therefore newly subject to LDAR monitoring. The number of valves in each IPU ranged between 82 and 1,078, depending on facility size and throughput (Figure 1). Monitoring data collected from these IPUs included the first two initial monthly monitoring events and the next four successive quarterly events (Figure 2). There were 4,815 valves inspected in the initial period. Of these, 125 were found leaking above the 10,000 ppm leak rate definition (Figure 3) for a calculated 1.7 percent leak frequency (Figure 6). Over the next four successive quarters the number of valves inspected in each quarter ranged from 4,743 to 4,813, and the new leak count ranged from 19 to 24 per quarter. The calculated average leak frequency was 0.4 percent per quarter.

Case Study 2 evaluated valve monitoring data collected over twelve consecutive calendar quarters in the IPU at six natural gas processing facilities with established, long-term LDAR monitoring programs dating back to 2009. The number of valves and inspections ranged between 248 and 1,398, depending on the facility and monitoring quarter (Figure 4), and the leak frequencies ranged between 0 and 11 per facility per quarter (Figure 5). The percent leak frequency at all locations was consistently less than 0.5 percent per quarter, and averaged 0.3 percent per quarter (Figure 8).

DISCUSSION

IDENTIFY FACILITIES WITH EQUIPMENT COMPARABLE TO WELL PRODUCTION FACILITY EQUIPMENT AND EVALUATE LEAK FREQUENCIES FOR THIS EQUIPMENT.

Natural gas processing facilities and petroleum refineries typically have a higher volume of material moving through piping, higher temperature fluctuations, and higher pressure operating conditions than well production facilities as defined in Colorado Regulation 7. Well Production Facilities as defined in Regulation 7 (Section XVII.A.15) operate with significantly lower throughputs, smaller temperature fluctuations, and at lower or atmospheric pressures. Therefore, it is anticipated that the leak rates will be significantly lower than other types of facilities.

As discussed in the methodology section, it was determined that there are many similarities between the equipment and throughput found in a IPU of a natural gas plant and the equipment and throughput of a well processing unit defined in the Colorado Regulation 7. Therefore, monitoring data collected at IPUs make a good case study for determining expected leak frequencies at Colorado's well production facilities and compressor stations. The gas plant facilities selected in this study are located across five western states in high to low elevations with seasonal temperatures ranging from high 90's to below zero. As presented in the results section, the leak rates in the IPUs across all 14 facilities were consistently low with little fluctuation. The results in these case studies are consistent with the EPA's expectations presented in Figure 5-35 in the EPA Protocol (See Figure 7). Similar to the leak rate graph for Case Study 1 (Figure 6), Figure 7 presents an immediate reduction in leak frequency following the implementation of an LDAR program, and both graphs report a much lower and consistent leak frequency in the following quarterly monitoring periods. These findings clearly demonstrate that LDAR programs with good work practice standards can quickly obtain a low leak frequency.

COLORADO REGULATION 7 DOES NOT ALLOW SKIP PERIOD MONITORING

The ability to use "skip period" (or "step down") monitoring based on actual leak rate performance is an accepted work practice under most Federal and many state LDAR regulations. In essence, the practice of "skip period monitoring" allows for reduced monitoring frequency resulting from demonstrated good performance. For example, several EPA regulations allow an owner or operator to monitor once every two quarters if the valve leak frequency is less than one percent in a process unit. Alternatively, the owner or operator may monitor once every four quarters if the valve leak frequency

is less than 0.5 percent in a process unit. In addition, EPA has recently written skip period monitoring protocols into the proposed National Uniform Emission Standards (40 CFR Subpart 65) (Federal Register Volume 77, pages 17897 – 18050) as well as a recent refinery consent decree (BP Whiting, September 28, 2012); indicating that the EPA's current enforcement philosophy has changed to allow skip period monitoring, even under punitive enforcement approaches.

Although proposed by industry, Colorado's final regulation does not incorporate the concept of "skip period monitoring." The Colorado Air Quality Control Commission did recommend further evaluation of skip period monitoring at a later date, but currently there is little real incentive for operators to implement an aggressive LDAR program that emphasizes prompt repair of leaking components and replacement of components with low-emitting emissions packing material.

THE EMISSION FACTORS SPECIFIED IN COLORADO REGULATION 7 WILL OVERESTIMATE EMISSIONS INVENTORIES

Colorado Regulation 7 Sections XVII.F.2 and XVII.F.4 references the Screening Ranges Approach (Table 2-8) in Section 2.2.1 of the 1995 EPA Protocol to determine an inventory of emissions for well production facilities and natural gas compressor stations. The oil and gas sector data used in the EPA Protocol document is based on a 1995 study commissioned by the American Petroleum Institute and the Gas Research Institute, conducted by Star Environmental in 1993 and 1995. This dataset has a sample size of 368 components across 24 facilities (see EPA Protocol, Table C-1). According to EPA, the majority of the 24 facilities studied were "uncontrolled," implying that these facilities did not have existing LDAR programs. The emission factors resulting from this study assume that measured readings less than 10,000 ppm were not leaks and therefore not repaired. The Colorado Regulation 7 leak limits (when measured by Method 21) are generally 500 ppm at new or existing well production facilities and 2,000 ppm at compressor stations and existing non-well production facilities (see Section XVII.F.6). Because repairs will be made more frequently and at significantly lower leak definitions than assumed in the EPA Protocol Screening Range emission factors, the calculated uncontrolled actual emissions for Colorado Regulation 7 facilities will be significantly overestimated.

COLORADO REGULATION 7 USES EMISSION FACTORS TO DETERMINE MONITORING FREQUENCY

Under Colorado Regulation 7, the monitoring schedules are based on uncontrolled actual emissions, and range between monthly, quarterly, and annually. The monitoring frequency at compressor stations is based on estimated uncontrolled actual emissions from fugitive sources. The monitoring frequency at well production facilities is based on uncontrolled actual storage tank emissions. The estimated uncontrolled actual emissions at compressor stations (that are based on the EPA Protocol emission factors) will be inflated because they will not reflect actual performance due to lower leak definitions and more frequent repair schedules. This over estimation may result in a determination for a more frequent monitoring schedule than required to maintain targeted emissions inventories.

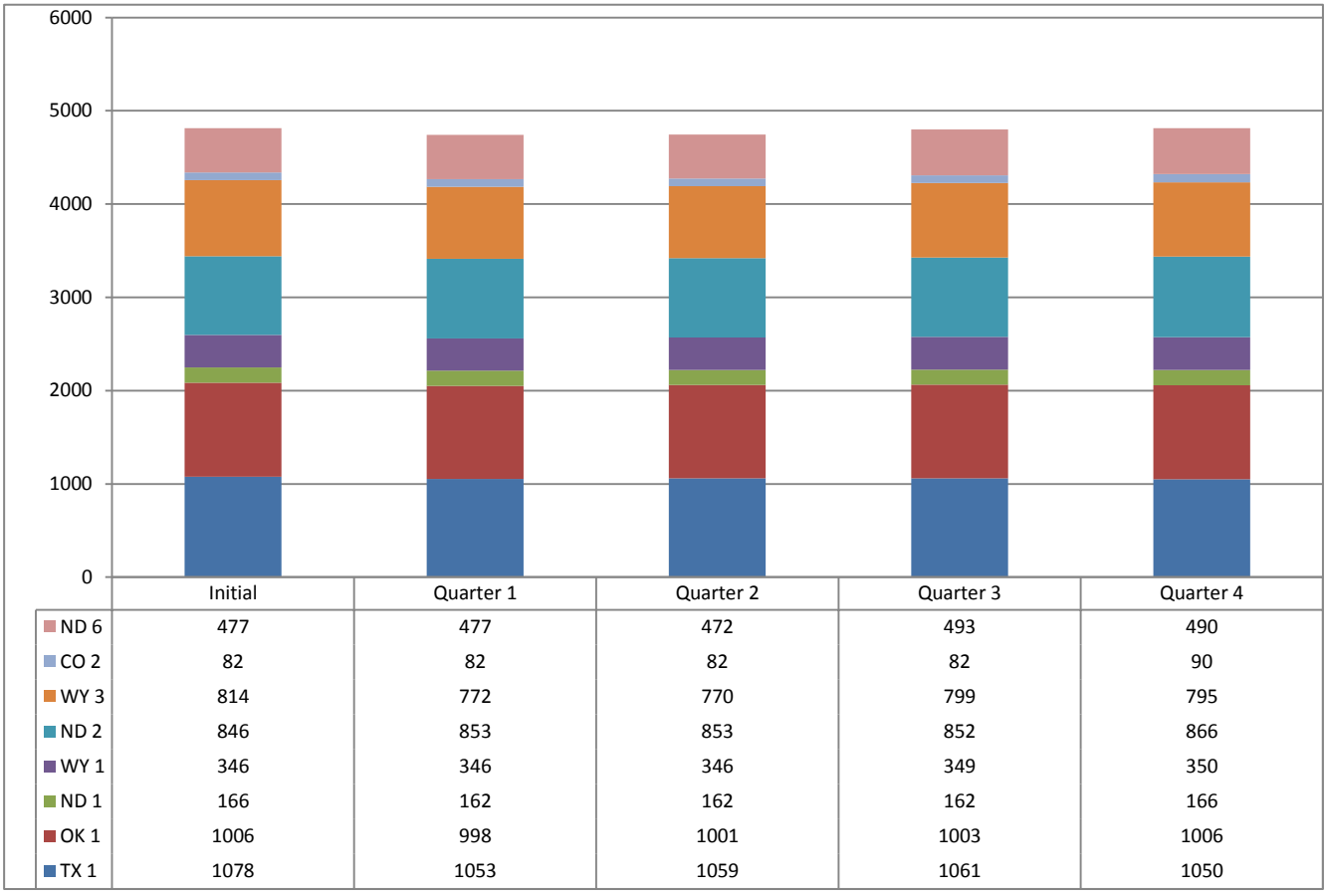
CONCLUSIONS

The monitoring data collected in the IPUs of this study clearly demonstrate that the valve leak frequency drops significantly following the initial implementation of an LDAR program, and that a low leak frequency is sustainable in a long-term quarterly monitoring schedule under a well-managed LDAR program.

By omitting skip period monitoring protocols and basing inventory emissions calculations on overstated uncontrolled emission factors, Colorado Regulation 7 will penalize operators with higher performing LDAR programs over other facilities. For example, consider two identically sized facilities where the first facility maintains a perfect LDAR monitoring performance with zero percent leaks, and the second facility reports a 100 percent leak frequency. Under Colorado Regulation 7, both facilities are required to maintain the same monitoring frequency, and both facilities would report the same emissions inventory even though the actual emissions at the first facility would be dramatically lower than emissions at the second facility.

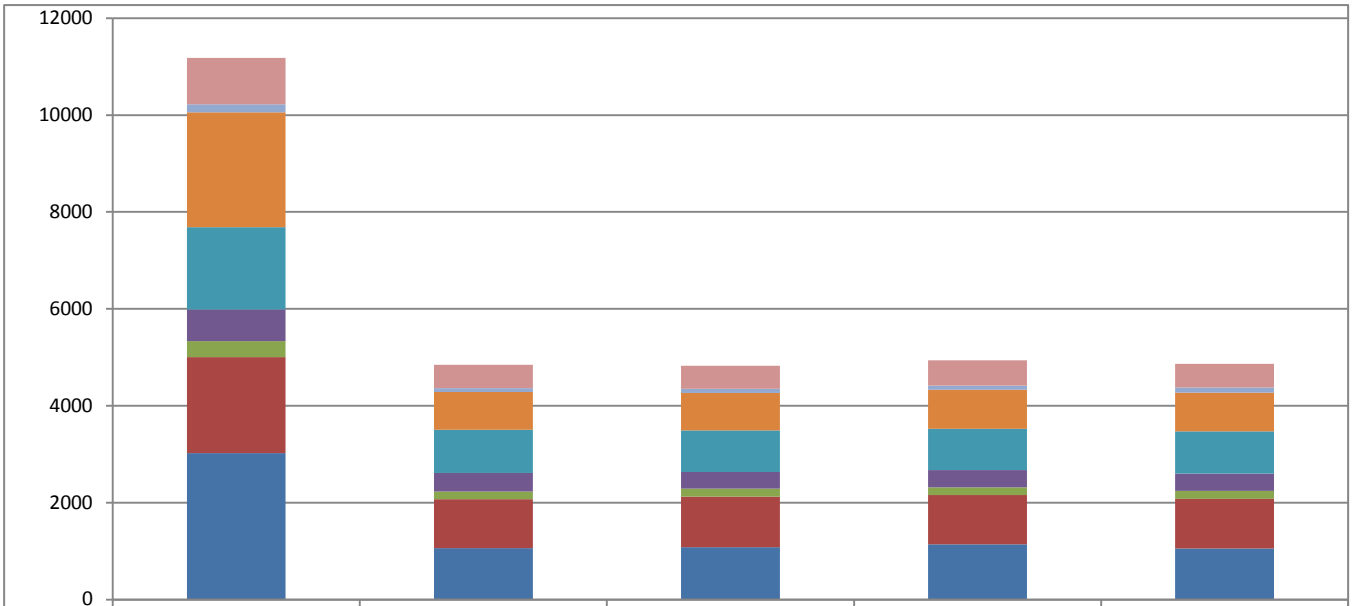
Regulatory agencies must carefully consider the data sources they use to define regulation requirements. Factors such as equipment types, processes, throughputs, monitoring frequencies, and leak rates can all have an impact on the final inventory of emissions at a facility.

Figure 1. Number of valves inspected in Case Study 1.



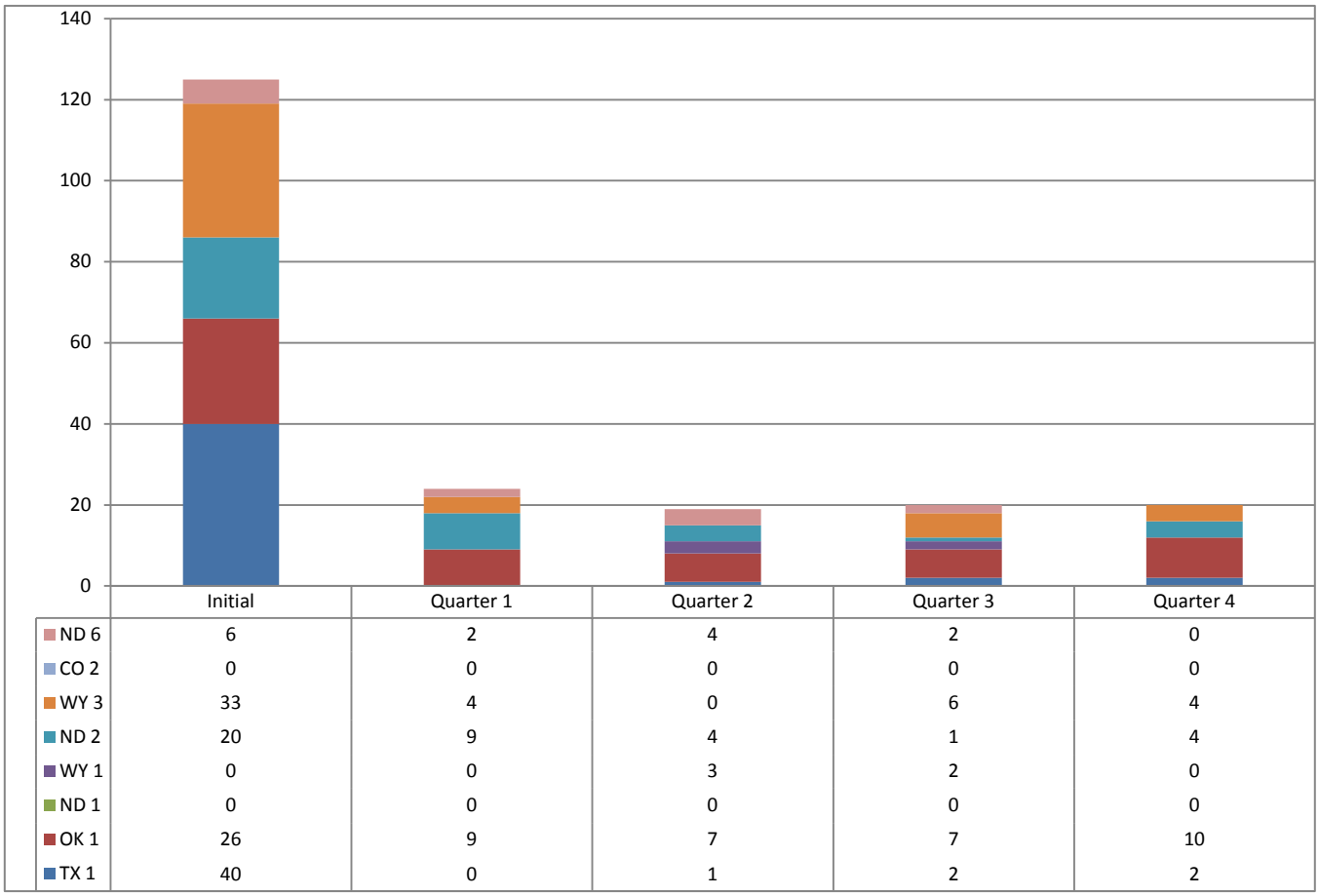
	Initial	Quarter 1	Quarter 2	Quarter 3	Quarter 4
ND 6	477	477	472	493	490
CO 2	82	82	82	82	90
WY 3	814	772	770	799	795
ND 2	846	853	853	852	866
WY 1	346	346	346	349	350
ND 1	166	162	162	162	166
OK 1	1006	998	1001	1003	1006
TX 1	1078	1053	1059	1061	1050

Figure 2. Number of inspections completed in Case Study 1.



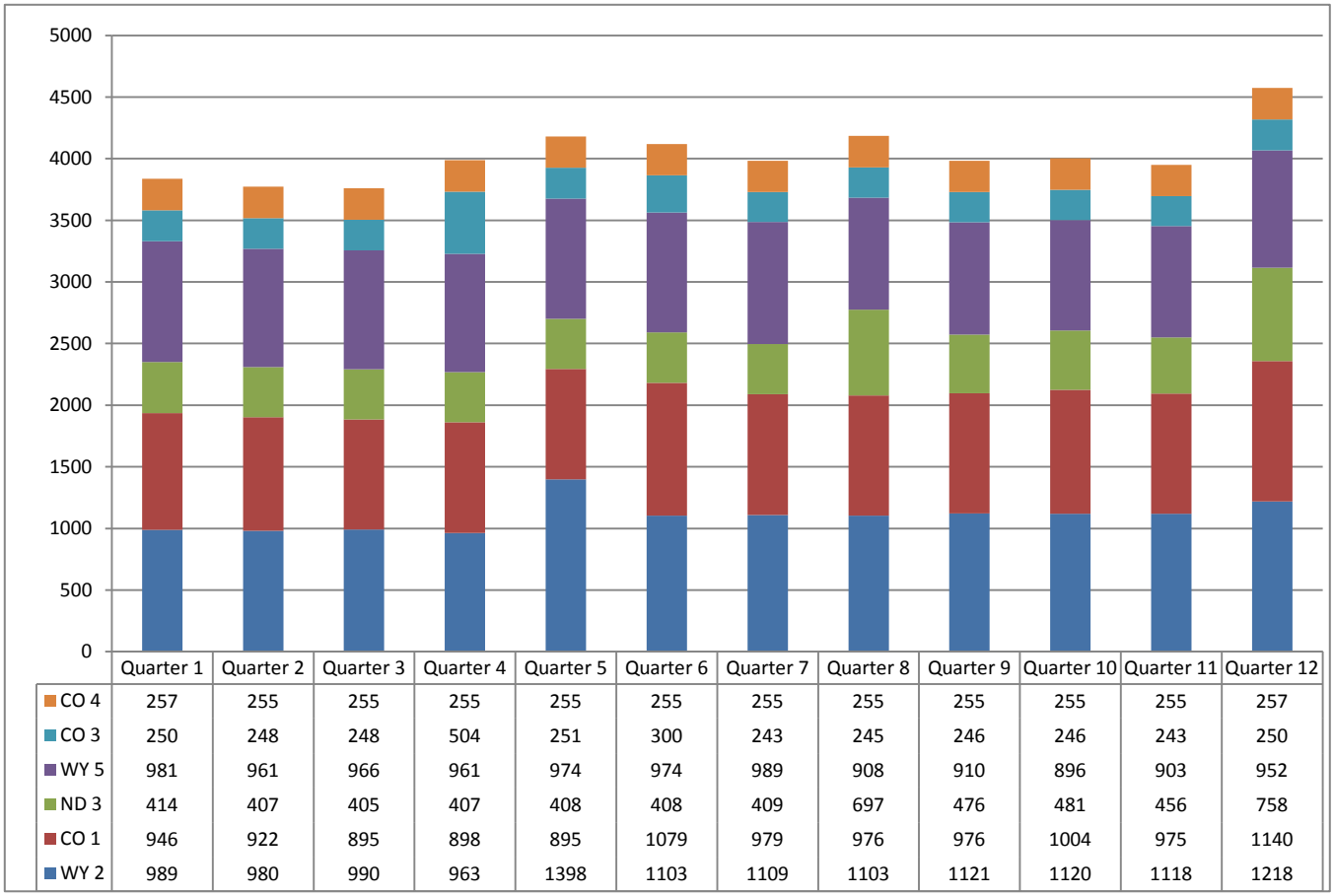
	Initial	Quarter 1	Quarter 2	Quarter 3	Quarter 4
ND 6	959	482	476	519	490
CO 2	164	82	83	84	100
WY 3	2376	781	773	805	804
ND 2	1692	890	859	854	869
WY 1	659	379	346	355	355
ND 1	328	162	162	162	166
OK 1	1980	1009	1042	1016	1028
TX 1	3024	1062	1084	1140	1052

Figure 3. Number of new leaks found in Case Study 1.



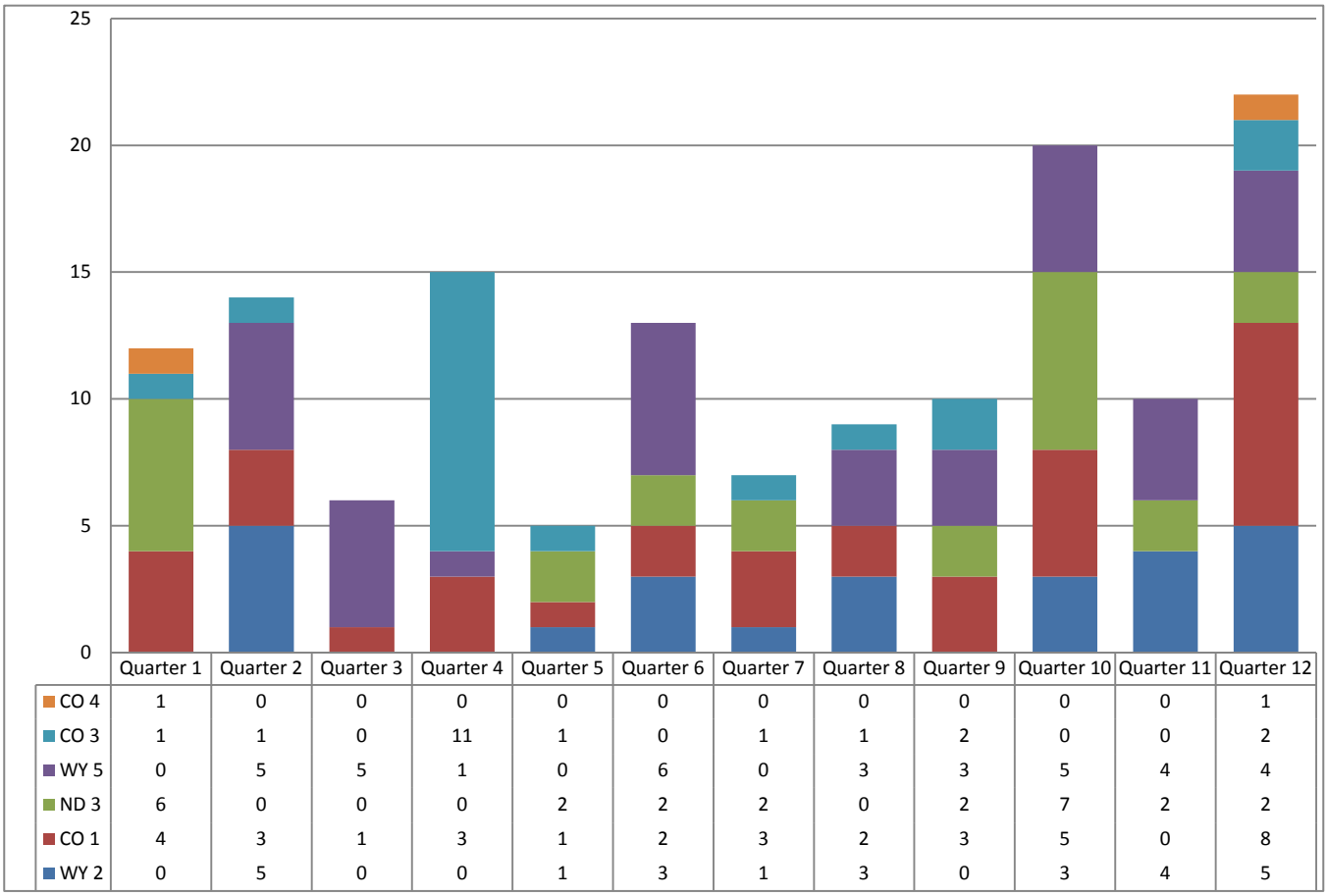
	Initial	Quarter 1	Quarter 2	Quarter 3	Quarter 4
ND 6	6	2	4	2	0
CO 2	0	0	0	0	0
WY 3	33	4	0	6	4
ND 2	20	9	4	1	4
WY 1	0	0	3	2	0
ND 1	0	0	0	0	0
OK 1	26	9	7	7	10
TX 1	40	0	1	2	2

Figure 4. Number of inspections completed in Case Study 2.



	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Quarter 5	Quarter 6	Quarter 7	Quarter 8	Quarter 9	Quarter 10	Quarter 11	Quarter 12
CO 4	257	255	255	255	255	255	255	255	255	255	255	257
CO 3	250	248	248	504	251	300	243	245	246	246	243	250
WY 5	981	961	966	961	974	974	989	908	910	896	903	952
ND 3	414	407	405	407	408	408	409	697	476	481	456	758
CO 1	946	922	895	898	895	1079	979	976	976	1004	975	1140
WY 2	989	980	990	963	1398	1103	1109	1103	1121	1120	1118	1218

Figure 5. Number new leaks found in Case Study 2.



	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Quarter 5	Quarter 6	Quarter 7	Quarter 8	Quarter 9	Quarter 10	Quarter 11	Quarter 12
CO 4	1	0	0	0	0	0	0	0	0	0	0	1
CO 3	1	1	0	11	1	0	1	1	2	0	0	2
WY 5	0	5	5	1	0	6	0	3	3	5	4	4
ND 3	6	0	0	0	2	2	2	0	2	7	2	2
CO 1	4	3	1	3	1	2	3	2	3	5	0	8
WY 2	0	5	0	0	1	3	1	3	0	3	4	5

Figure 6. Average percent new leaks found over number of valves inspected in Case Study 1.

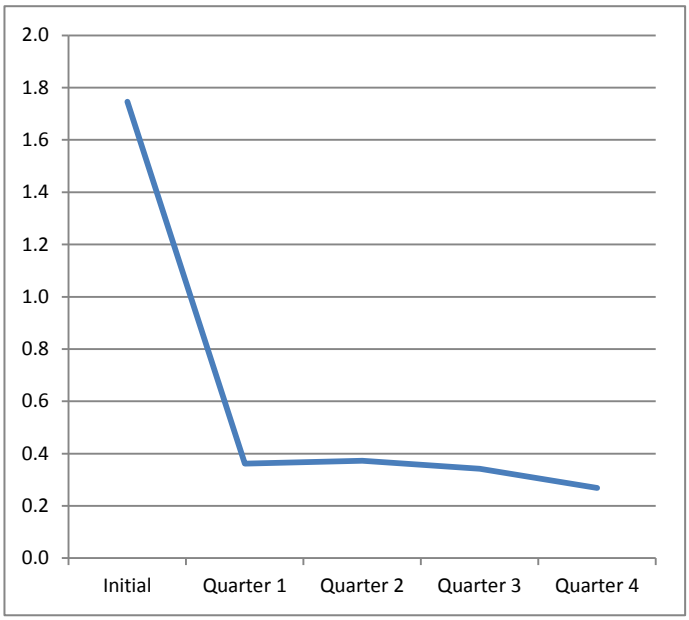


Figure 7. Changes in Leak Frequency after implementation of an LDAR Program. Figure 5-35, EPA-453/R-95-017.

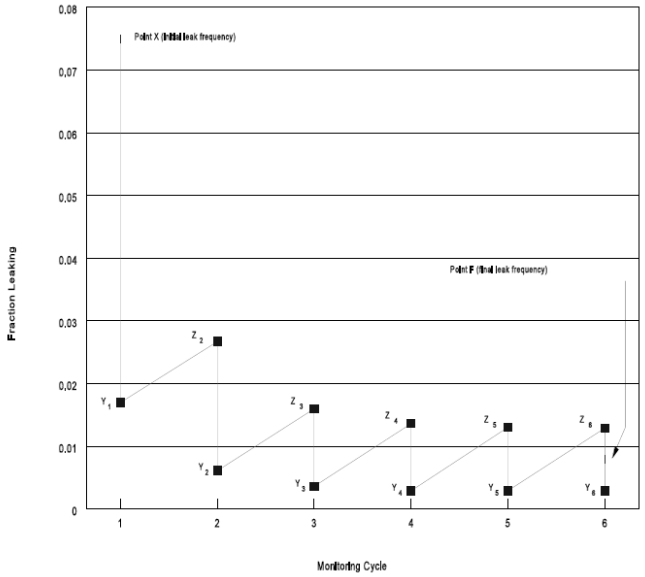


Figure 8. Average percent new leaks found over number of inspections completed in Case Study 2.