COLORADO

Department of Natural Resources
Oil and Gas Conservation Commission

RISK-BASED INSPECTIONS

Strategies to Address Environmental Risk Associated with Oil and Gas Operations

Prepared for the following Committees of the Colorado General Assembly:

Joint Budget Committee

House Agriculture, Livestock, and Natural Resources Committee

Senate Agriculture, Natural Resources, and Energy Committee

Prepared by the Colorado Oil and Gas Conservation Commission

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FINAL REPORT

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EXECUTIVE SUMMARY

The Colorado Oil and Gas Conservation Commission ("Commission") is directed by a recent statute to use a risk-based strategy to inspect oil and gas facilities. § 34-60-106 (15.5), C.R.S. (2013) (Senate Bill 2013-202). The Commission's risk-based strategy prioritizes the phases of oil and gas operations that are most likely to experience spills, excess emissions, and other types of violations for inspections.

The purposes of a risk-based inspection strategy are to protect public health, minimize environmental contamination, detect spills before they worsen, and strengthen the public's trust in the State of Colorado's oversight of the oil and gas industry.

This report fulfills the statutory requirement for a Commission report to the General Assembly by February 1, 2014 concerning its risk-based inspection strategy. The statute directs the Commission to include findings and recommendations in this report, as well as a plan for changes to its inspection program, including staffing and equipment needs.

To improve the Commission's current inspection program, operational risk should be a primary factor for allocating inspection resources. Key priorities in that allocation were developed from analysis of more than three years of spill and release reports submitted by operators and detailed interviews of Commission staff.

This report offers findings and recommendations for taking a more risk-based approach in prioritizing inspections of oil and gas operations.

Findings

The report's eight findings are summarized below:

1. **Spills and releases are most likely to occur during the production phase of oil and gas operations in Colorado.**

2. **Spills and releases that occur subsurface may not be identified during the normal inspection process.**

3. **The Commission does not routinely review production facility maintenance records.**

4. **The Commission should monitor the installation and operation of flowlines.**

5. **Historic spills from oil and gas operations must be identified and remediated during facility site closure review.**

6. **The Commission should receive notice of construction, reclamation, and drilling activities.**

7. **The Commission could rebalance inspection resources to provide additional inspections of hydraulic fracturing operations.**

8. **The Commission's Form 19 will be revised to standardize data entry and reporting requirements.**

Recommendations

From these findings, the Commission proposes the following four recommendations for improvement to its risk-based inspection program in Colorado:

1. **The Commission should review integrity test results and inspect production facilities more frequently.**

2. **The Commission should increase inspections during production facility closures.**

3. **The Commission should conduct more time-specific inspections of construction, reclamation, and drilling activities using improved notice from operators.**

4. **The Commission should increase its inspection frequency of hydraulic fracturing operations.**

This report includes a plan for implementing the Commission's recommendations. It also includes estimates of the appropriations that would be necessary to implement the recommendations.

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CHAPTER 1: INTRODUCTION

This report fulfills a requirement contained in a recent Colorado statute. Senate Bill 13-202, titled “Concerning Additional Inspections of Oil and Gas Facilities,” was approved during the first regular session of the 69th Colorado General Assembly. Governor Hickenlooper signed this legislation into law on May 24, 2013. This new law added Section 34-60-106 (15.5) to the Colorado Oil and Gas Conservation Act (“Act”).

This new law, provided in this report as **Appendix A**, directs the Colorado Oil and Gas Conservation Commission (“Commission”) to adopt a risk-based strategy for inspecting oil and gas locations. It requires the Commission to focus on the following aspects of its inspection program:

- ► Use a risk-based strategy for inspections of oil and gas locations
- ► Prioritize more in-depth inspections
- ► Improve the frequency and timing of inspections.

The intent of this new law is for the Commission’s inspection program to target the operational phases of oil and gas exploration and development most likely to experience spills, excess emissions, and other types of violations. Such a risk-based inspection program will conduct timely inspections, detect spills before they worsen, and increase the public’s trust in the Commission’s oversight of oil and gas operations. It will also better protect public health, safety, welfare, and the environment.

The new law directs the Commission to submit to the General Assembly, by February 1, 2014, a report containing findings, recommendations, and estimates of staffing and equipment needed for the implementation of changes to the Commission’s current risk-based inspection program. These elements are included in the following report.

1.1 Report Goal

The goal of this report is to evaluate in detail the required modifications to the Commission’s current risk-based inspection program in Colorado. It describes the phases of oil and gas operations that pose the greatest risk to the environment. It evaluates the Commission’s current inspection program to identify opportunities for rebalancing inspection resources to increase the frequency of inspections during the highest risk operational phases of oil and gas development. Finally, it provides a plan to accomplish the changes necessary to improve the Commission’s risk-based inspection program statewide.

In its 63 years of regulating oil and gas activity, the State of Colorado has built an effective framework of statutes, rules, orders, policies, and best practices that, taken together, regulate a highly competitive industry in a market defined by technological change. This regulatory framework recognizes that ongoing communication between the Commission, the public, oil and gas operators, local governments, and other state and federal agencies will contribute to an effective and efficient regulatory program. This report is an important part of the Commission’s commitment to this communication.

Effective regulation also requires a careful review of available options in order to keep pace with industry changes in technology and economics. Appropriate modifications to Colorado’s framework of statutes, rules, and policies are necessary as the industry changes. This report is a part of the ongoing process of response to industry and societal changes.

This report describes the analysis the Commission conducted to clarify the magnitude of spills and releases, how and when these spills occur, and whether the current framework effectively reduces risk in each phase of oil and gas operations. This report identifies gaps where the Commission’s existing inspection program could be modified to better respond to certain operations with high risks of spills, releases, and environmental contamination. It then outlines a plan to implement an improved risk-based inspection approach.

1.2 Report Structure

This report is organized into five chapters and three appendices. Chapter One describes the legislation, goals, and objectives that prompted this risk-based inspection analysis. Chapter Two presents the approach for evaluating risks by phase and identifying potential options for revising the existing inspection program. It also identifies key participants in the effort, including Commission staff teams and outside consultants.

Chapter Three describes the Commission’s current field inspection program, detailing how current inspections are prioritized by multiple risk-based factors. This chapter also presents important information about the Commission’s existing work units and how these groups coordinate action on a variety of inspections, permits, reports, and data analysis tools.

Chapter Four presents an analysis of three sets of data developed during this project, an evaluation of existing Commission systems in place, and a gap analysis for the Commission’s existing programs. The gap analysis focused on improving the Commission’s management of environmental risk by each phase of oil and gas operations.

Chapter Five presents a plan for changes to the Commission’s risk-based inspection program. It contains the Commission’s findings and recommendations supporting revisions to the current risk-based inspection program as required by the new statute. Each modification is accompanied by an estimate of one-time and ongoing annual budgetary impacts in the areas of staffing, database changes, and equipment, as appropriate.

The appendices to this report provide additional technical and legal context:

- ► SB 13-202, as enacted
- ► Outside expert analysis of operator spill and release reports
- ► Current Commission Rules and policies on wellbore integrity and hydraulic fracturing.

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CHAPTER 2: RELATIVE RISK EVALUATION

This chapter describes the Commission's evaluation of the relative risk of each phase of oil and gas development. It explains how existing Commission programs manage this risk in accordance with Colorado law.

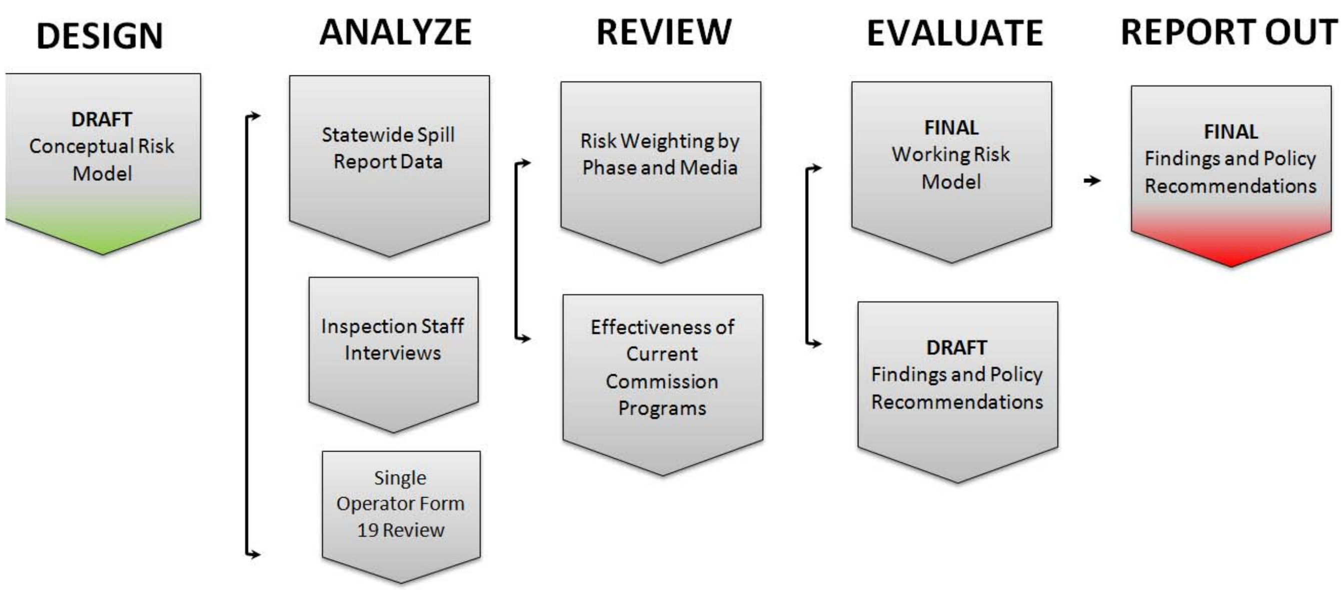
To evaluate existing programs, the Commission developed a conceptual risk model. This model includes seven major phases and eighteen sub-phases of oil and gas activity. The model qualitatively evaluated risks to four major categories of environmental media (air, surface water, groundwater, and soil) through thirteen potential impacts from the full cycle of oil and gas development.

Section 2.1 presents an overview of the Commission's conceptual risk model, component by component. This overview is followed by a description of the Commission's approach to validating the model using (i) spill and release (Form 19) data filed by the industry with the Commission, (ii) interviews of Commission inspection staff, and (iii) a sample of remediation reports filed by the industry with the Commission.

This chapter concludes with a description of the internal review of the model provided by each major work group of the Commission. The suggestions from this detailed work group review were the final step in developing the working risk model used in this project.

The project approach is depicted graphically in **Figure 2-1**.

Figure 2-1: Risk Based Inspections Project Method



2.1 Conceptual Model Design

The purpose of the conceptual model is to establish risk assignments for media and pollutants across each phase of oil and gas development. The model is independent of geographical location, so risk assignment is conducted to assign the highest potential risk, taking into account *all* developing and developed oil and gas fields in the state. In many cases, a particular phase of development might pose extremely low risk when evaluated by a particular environmental media (such as air or water), while the risk increases in another operational phase for a particular impact on the same media.

Identification of Phases

For the purpose of evaluating risk and inspection program adequacy, the Commission identified seven major phases and eighteen sub-phases of oil and gas operations. This breakdown captures the full range of regulatory activity under the Commission's purview (see **Figure 2-2**).

Some phases of oil and gas operations, such as mineral leasing, interstate transmission, and product sales, are excluded from the analysis. These excluded phases either pose no risk to public health or the environment, or are not regulated by the Commission.

Figure 2-2: Oil and Gas Operational Phases Studied

Phase	Subphase
Construction	Location Access Roads Reclamation
Drilling	Move In / Rig Up Rig Down / Move Out Drilling Casing Drilling Fluid Management
Stimulation	Equipment Mobilization Hydraulic Fracturing Flowback
Production	Facility and Equipment Operation and Maintenance Well Integrity Production Facility Closure
Workover	
Plugging	
Flowlines	Construction Operations Repair / Modification Reclamation

Identification of Risks and Media

To evaluate risk and regulatory program adequacy, the Commission identified four major environmental media and fifteen risks (pollutants or impacts). These capture the full range of possible risks from regulated phases of oil and gas operations (see **Figure 2-3**).

Figure 2-3: Risks by Environmental Media

Media	Risk or Impact
Air	Dust Volatile Organic Compounds Silica Methane
Surface Water	Sedimentation Chemical Spills / Releases Produced Water Volatile Organic Compounds Methane
Groundwater	Methane Volatile Organic Compounds Produced Water Chemical Spills / Releases
Additional Risk Types	Vapor Intrusion Physical Contact

This definition of the four media and particular pollutants or impacts associated with each medium allow the Commission to address whole regulatory programs and the pollutants common to each step in oil and gas development.

The Commission notes that release of some of these pollutants is regulated under other federal or state statutes. Coordination between the Commission and other federal or state agencies is an important element of an effective regulatory framework, but a discussion of multi-agency coordination is not part of this report.

Assignment of Risk Level

The Commission's conceptual risk model recognizes the complexity of oil and gas development, the potential risks associated with each phase of development, and the spectrum of regulatory programs that should be evaluated to determine whether a risk can be better managed.

Because the menu of risks, operational phases, and existing programs is quite large, the Commission required a method to focus upon the most important risks and how these risks are managed by current Commission programs. Each risk and phase-of-operation pair was assigned a ranking of 1 through 5. Higher numerical rankings (entries such as a 4 or a 5) indicate more probable occurrence of risk. Lower rankings (entries such as a 1 or a 2) indicate less probable occurrences of risk. Middle level rankings (a 3) are moderate occurrences of risk that may or may not require a regulatory response.

Coloring is used in the Commission's model to classify risks. Examples of different portions of the Commission's risk model are shown below in **Figures 2-4** and **2-5**.

Light yellow identifies a *system in place* – in which existing regulatory programs adequately mitigate the impact or effectively manage the risk, so that no recommendation would be made to change the Commission's current approach. Light blue in the model identifies pairs of operational phase and risk that denote a change required in an existing regulatory program.

In this report, the Commission evaluated risks in terms of the *likelihood of an impact occurring.* The Commission did not attempt to evaluate the degree of the impact in terms of toxicity, mortality, morbidity, or any other qualitative measure of the degree of environmental impact.

A legend of the abbreviations used in the risk model is provided below. Some of this coding identified a Commission work group potentially responsible for implementing a policy or operational change:

- ► I-FT – Field Inspection
- ► HE – Hearings and Enforcement
- ► G/P – Issue New Guidance and Policy
- ► I-ENV – Environmental Inspection
- ► I-ENG – Engineering Inspection
- ► PR – Permitting/Technical Support- additional review or addition of condition of approval on 2 or 2a
- ► ENV – Environmental
- ► SIP – *System in Place*.

Figure 2-4: Production Phase, Production Facility Closure Sub-phase, Groundwater Media Cells from Model

	RISKS TO THE ENVIRONMENT			
	Groundwater			
OPERATIONAL PHASE	Methane	VOCs	Produced Water	Chemical Spills, Releases
Production Facility Closure	1	4 I-FT I-ENV ENG G/P	4 I-FT I-ENV ENG G/P	1

Figure 2-5: Production Phase, Well Integrity Sub-phase, Groundwater Media Cells from Model

	RISKS TO THE ENVIRONMENT			
	Groundwater			
OPERATIONAL PHASE	Methane	VOCs	Produced Water	Chemical Spills, Releases
Well Integrity	5 SIP	4 SIP	2	1

2.2 Validation of the Commission's Model

To validate the content of the Commission's conceptual model, including phases of oil and gas operations, risks, and rankings, the Commission reviewed operator reports on spills. It also documented staff experience with environmental risk management. Finally, the Commission reviewed site remediation data provided by a single operator active in three counties.

Details of each approach are provided in this section.

Evaluation of Spill Data

For the last 20 years, the Commission has required operators to report spills associated with oil and gas activities that are five barrels (bbls) or greater in volume (or any volume if the spill impacts the State's waters). These reports are made to the Commission using the Form 19 Spill/Release Report. The Commission stores the Form 19 information in its COGIS database. Effective February 1, 2014, operators are required to report spills and releases greater than one barrel that occur outside of secondary containment.

The Commission retained a nationally renowned environmental consulting firm, S.S. Papadopulos and Associates, Inc. (SSPA), to evaluate 1,638 Form 19 Spill Reports submitted between January 2010 and August 2013. Using data culled from the Spill Reports, SSPA determined the operational phases that pose the highest probability of spills and releases. SSPA also studied the causes, associated equipment, location, and size of the spills.

SSPA's final report is included as **Appendix B.** Major results from this work are discussed in Chapter 4.

Interviews of Field and Environmental Staff

The Commission retained a second, independent environmental consultant to interview a cross-section of the Commission field inspection and environmental staffs as a part of the validation of its model. The consultant asked about risk, prioritization, and the tools inspectors use in the field to perform their duties.

These interviews collected in-depth information on observed environmental issues, including the most frequently observed environmental risks and the operational phases Commission staff considered most likely to cause environmental risk. The consultant also evaluated training performance by measuring whether staff were effectively using the current risk-based inspection tools.

When time allowed, the interview included a ride-along with the Commission staff member in order to gain understanding and insight into the day-to-day focus of the field inspection team. Seven interviews included ride-along site inspections with the inspector. The ride-alongs encompassed diverse producing areas in the state, including the Wattenberg area in Weld, Adams and Boulder Counties, Morgan County in Northeastern Colorado, Garfield County in the Piceance Basin, mountain locations in Routt County, and the Raton Basin in Las Animas County. These visits included a diversity of small, medium, and large operator sites, as well as older and newer production sites, a drilling operation, and a completions operation.

Examination of Operator Information

In addition, to validate the Commission's model and as a test case for how operator data may be used to determine causes of actual spills, three years (2011-2013) of spill data from a single operator were evaluated by the Commission. The operator has facilities in various regions of Colorado and is currently in the process of upgrading facilities and replacing older equipment at recently acquired facilities.

2.3 Working Model and Development of Policy Options

The final steps in the Commission's work began with the review of the risks identified in the Conceptual Model. Next, from a list of highest priorities, the Commission determined which risks are adequately managed under existing regulatory programs. Then, as directed by Section 34-60-106 (15.5), the Commission's recommendations were paired with staffing and budget requirements.

Work Group Review

Once the conceptual model was complete and validated using (i) the relative probabilities of accidental spills and releases identified in the Commission's spills database and (ii) interviews recording the professional experience of Commission field staff, the Commission refined the model through four rounds of internal review. Groups of two to five individuals who are specialists in permitting, engineering, environmental review, and enforcement were convened to discuss the risk weightings and how current regulatory programs at the Commission manage identified environment risks.

Comments taken from the Commission's work group discussions refined the following aspects of the Commission's conceptual risk model:

- ► Risk assignment to pollutants or impacts by phase of operation
- ► Segment definitions of phases and sub-phases of operation
- ► Completeness of media, pollutants, and impacts
- ► The role of Commission work group functions when addressing each risk
- ► Best practices for managing future risks identified in the model.

The changes suggested in this review transformed the conceptual model into the working risk model used by the Commission in its analysis.

Risk Priorities and Systems in Place

Weighted risks from all operational phases of oil and gas development were evaluated against existing Commission inspection protocols and associated regulatory programs. If a program adequately addresses a key environmental risk, details are provided so that the reader will know how the program works, how the program has evolved over time as industry conditions have changed, and what legal framework, statutory or rule-based, supports the program.

Gap Analysis and Commission Recommendations

The Commission identified some risks that are not being fully addressed by existing inspection paradigms. The Commission is recommending changes to its inspection programs and policies to fill these gaps.

The Commission's recommendations include some changes that augment existing regulatory activities without a need for new statutes, rules, or policies. The recommendations also include some changes for which General Assembly action is required. These changes include recommendations that must be funded through new budget appropriations.

Each policy option is given a narrative summary and a quick reference scorecard. The scorecard contains first-order estimates of one-time and ongoing state government fiscal impacts if the recommendation were to be legislatively and administratively implemented.

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CHAPTER 3: CURRENT COMMISSION PROGRAMS

This chapter presents an overview of the current Commission organization with a particular focus on its inspection function. The discussion covers each step in the inspection process: assigning its inspectors to a territory; providing tools to help inspectors document and share critical information from the inspection; and monitoring inspector progress in meeting the Commission's regulatory goals.

An understanding of the current inspection program informed the subsequent analysis of environmental risks and possible changes for making the program more effective at minimizing these risks.

3.1 Commission Work Group Interdependence in the Regulation of Oil and Gas Operations

The Commission carries out its regulatory duties under the Oil and Gas Conservation Act with its staff configured into five work groups. These staff workgroups are:

- ► Permitting/Technical Support
- ► Engineering
- ► Inspections
- ► Environmental
- ► Enforcement.

The oil and gas development and production activity the Commission regulates can be summarized as five broad phases of operations:

- ► Construction
- ► Drilling
- ► Stimulation
- ► Production
- ► Abandonment.

The field inspection and enforcement work groups have responsibilities in all five phases of oil and gas operations. Other Commission work groups may only be active in a few of the phases of operations.

Within each phase of oil and gas development, these Commission work groups share and act upon the information reported by operators to the Commission and the data collected by staff from field inspections. The interactions of these work groups are essential to the proper functioning of a risk-based inspection system.

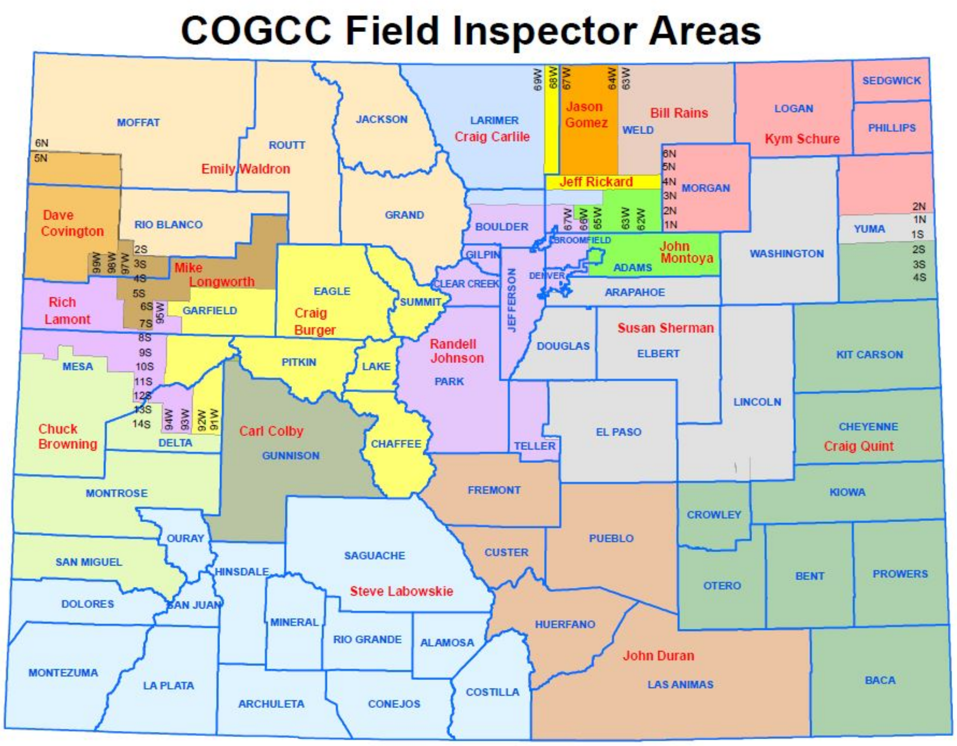
3.2 Current Commission Inspection Program

The Commission currently has a well-defined inspection program to manage the risk of oil and gas operations. This program operates according to existing internal polices and Information Technology (IT) processes. For any given oil and gas well, the need for an inspection is identified and prioritized based on that site's permit data, inspection data, and operator reports.

Inspection Unit Organization

Field inspectors are assigned to specific geographic areas (**Figure 3-1**) and work from home offices within their territory. Being assigned to and living within a dedicated territory has several important benefits. For example, reduced travel time allows inspectors to respond to complaints more promptly and improves the efficiency of routine inspections.

Figure 3-1: Inspection Staff Geographic Area Assignments



Note: In 2012, Gunnison County retained a contractor pursuant to an Intergovernmental Agreement between the Board of County Commissioners of Gunnison County and the Commission.

Assigning inspectors to a specific area also increases the inspector's understanding of common issues that occur in that region. For example, inspectors can track drill rigs and observe oil and gas locations as they move through the entire exploration and production life-cycle.

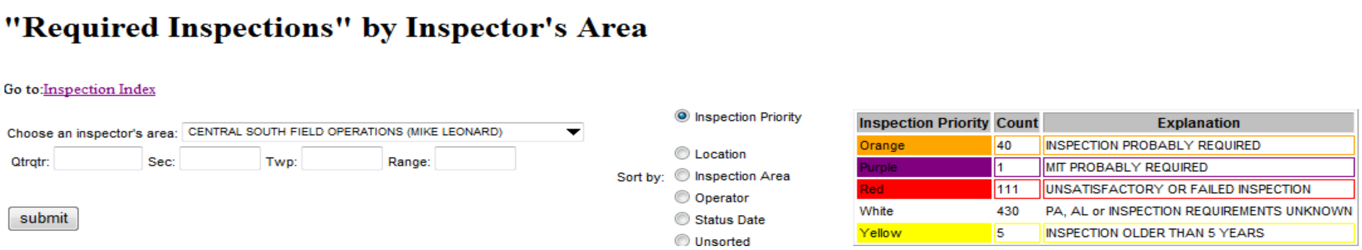
Inspection supervisors give an individual inspector a target number of inspections to complete each year. Inspectors are evaluated against this target through the annual performance management process. An inspector's individual goals also include performance targets for specific types of inspections, such as witnessing surface casing cementing, Mechanical Integrity Tests (MITs), or plugging and abandonment operations. Supervisors review the Commission's inspection database and meet with inspectors on a monthly basis to ensure targets are met.

Inspection Tools

Field inspectors use a number of IT processes, such as database reports, queries, and a Geographic Information System (GIS) to help plan and prioritize inspections. The IT tools use data from permitting, operator reporting, and field inspections to generate lists of inspections and to assign a preliminary priority (**Figure 3-2**).

For example, a well that has never been inspected has a higher priority than a recently inspected well. The same is true for wells that may have failed a recent inspection and wells that may require an MIT. Each inspector uses a laptop computer while in the field to access the agency's GIS program and its multiple data layers that provide detailed information on wells and inspection status (**Figure 3-3**). These IT tools greatly enhance the efficiency of the overall field inspection program.

Figure 3-2: Example Inspection Database Tool



"Required Inspections" by Inspector's Area

Go to: Inspection Index

Choose an inspector's area: CENTRAL SOUTH FIELD OPERATIONS (MIKE LEONARD)

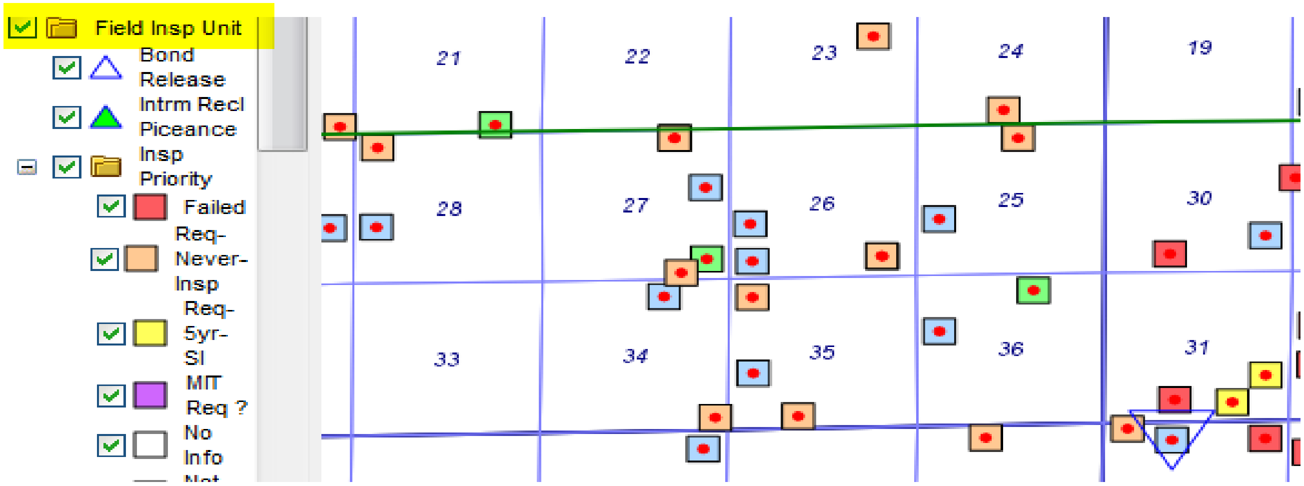
Qtrqtr: Sec: Twp: Range:

submit

Sort by: Inspection Priority, Location, Inspection Area, Operator, Status Date, Unsorted

Inspection Priority	Count	Explanation
Orange	40	INSPECTION PROBABLY REQUIRED
Purple	1	MIT PROBABLY REQUIRED
Red	111	UNSATISFACTORY OR FAILED INSPECTION
White	430	PA, AL or INSPECTION REQUIREMENTS UNKNOWN
Yellow	5	INSPECTION OLDER THAN 5 YEARS

Figure 3-3: Example GIS Inspection Layers



Site-specific and wellbore-specific risk analyses are conducted throughout the Commission's permitting processes. Staff from the permitting, engineering, and environmental work groups evaluate every application for a drilling permit and location permit. Conditions of approval (COAs) are attached to individual permits to address any site-specific risks identified during this evaluation.

For example, a condition of approval requiring the operator to provide prior notice of a specific operation allows Commission staff to witness that operation (**Figure 3-4**). These additional inspections may be conducted by field, environmental, or engineering staff. Because COAs are identified on the electronic field form available to each inspector, the inspector is aware of these additional requirements.

Figure 3-4: Example Condition of Approval on Application for Permit to Drill

API NUMBER	Permit Number:	Expiration Date: 2/15/2014
05 123		

CONDITIONS OF APPROVAL, IF ANY:

All representations, stipulations and conditions of approval stated in the Form 2A for this location shall constitute representations, stipulations and conditions of approval for this Form 2 Permit-to-Drill and are enforceable to the same extent as all other representations, stipulations and conditions of approval stated in this Permit-to-Drill.

Date Run: 2/16/2012 Doc [#400237995] Well Name: CASTOR PC LA 36-68HN ***Page 2 of 3***

1) Provide 24 hour notice of MIRU to Jim Precup by e-mail at james.precup@state.co.us. Indicate Spud Notice in the subject line and provide the following information: Operator Name, Well Name and Number, API #, Spud Date, Contact Name, Contact Phone #, Email Address.
2) Provide cement coverage from base of intermediate casing to a minimum of 200' above Niobrara. Verify coverage with cement bond log.
3) Run and submit Directional Survey from TD to base of surface casing. Ensure that the wellbore complies with setback requirements in commission orders or rules prior to producing the well.

Field Inspection Process and Documentation

During a field inspection, Commission staff document the results of the inspection on a seven-section form (**Figure 3-5**) covering the following topics:

- Location Summary
- Conditions of Approval
- Facility (the well or wells)
- Environmental
- Reclamation (Interim or Final)
- Stormwater Management
- Pits.

The Commission's field inspection form was greatly expanded in 2011. The Commission's database generates a PDF report that is emailed directly to the oil and gas operator at the conclusion of the inspection. Thus, the operator receives a rapid report of site conditions and the potential need for corrective actions.

The Commission also makes the completed inspection form available to the general public on the agency's website. The PDF reports also can be emailed to Commission staff to provide notice of problems or issues that may require additional expertise, such as managing a spill or release.

Figure 3-5: Example Corrective Action from Revised Site Inspection Report

Inspector Name: QUINT, CRAIG

Idle Well

Purpose: ☐ Shut In ☒ Temporarily Abandoned Reminder:

S/V: Violation CA Date: 04/07/2013

CA: Well must be either: 1) Put on production or 2) Per COGCC Rule 326.b.(1) a successful mechanical integrity test shall be performed on each temporarily abandoned well within thirty (30) days of the date the well becomes incapable of production or 3) Be properly plugged and abandoned. 4) A sundry requesting continued temporarily abandoned status should be submitted to Bob Koehler at the COGCC within thirty (30) days of receipt of this report - the sundry should detail the plan for the future operation of the well and the way the well is closed to the atmosphere. Shut-in and temporarily abandoned wells must be properly reported on COGCC Form 7, Operator's Monthly Production Report.

Comment: WELL IS ICAPABLE OF PRODUCING IN PRESENT STATE, DOWN HOLE EQUIPMENT HAS BEEN PULLED, WELL IS SHUT IN WITH A 2" BALL VALVE, M.I.T. HAS NOT BEEN PERFORMED, OPERATOR HAS A PROBLEM DOWN HOLE. REPAIR WELL AND PERFORM A PASSING MECHANICAL INTEGRITY TEST OR PLUG.

CHAPTER 4: ANALYSIS OF DATA AND CURRENT PROGRAMS

This chapter begins with a presentation of summary level data on environmental risk from (i) industry-filed spill reports, (ii) Commission field and environmental staff interviews, and (iii) operator remediation data. These three data sources provided comparative weighting of environmental risk according to the phase of oil and gas development. These data validated initial risk assignments in the Commission's conceptual risk model.

Next, the analysis evaluated all existing Commission risk management programs and systems to determine where additional effort should be placed to minimize known sources of environmental risk.

This chapter concludes with an analysis of gaps in these systems that, if filled, will best use Commission resources to protect public health, safety, welfare, and the environment.

4.1 Data Review

The Commission's review of operator spill reports, field staff interviews, and operator remediation reports provided critical data on phase-by-phase operational environmental risks, strengths and weaknesses in the Commission's existing inspection program, and opportunities to better manage risks. The Commission is using this data to reevaluate and refine its day-to-day work processes and inspection program.

Spill and Release Report Data Analysis

The Commission's outside expert, SSPA, categorized the data to identify the operational phase most likely to have a spill or release. Operational phases used for categorization included construction, drilling, completion, stimulation (hydraulic fracturing), production, work-over, and abandonment. SSPA worked to identify the cause of each spill, such as equipment failure, human error, nature, and vandalism.

SSPA also conducted a variability analysis to assess whether trends were consistent from year to year. This inter-annual analysis shows a breakdown of releases by operational phase and cause. With minor exceptions, the relative percentages of the operational phase most likely to experience a spill or release (see **Figure 3-1**), and the equipment most likely to have caused a spill (see **Figure 3-2**) did not vary greatly from year to year.

Figure 4-1: Releases by Operational Phase and Year (Percent of Total)

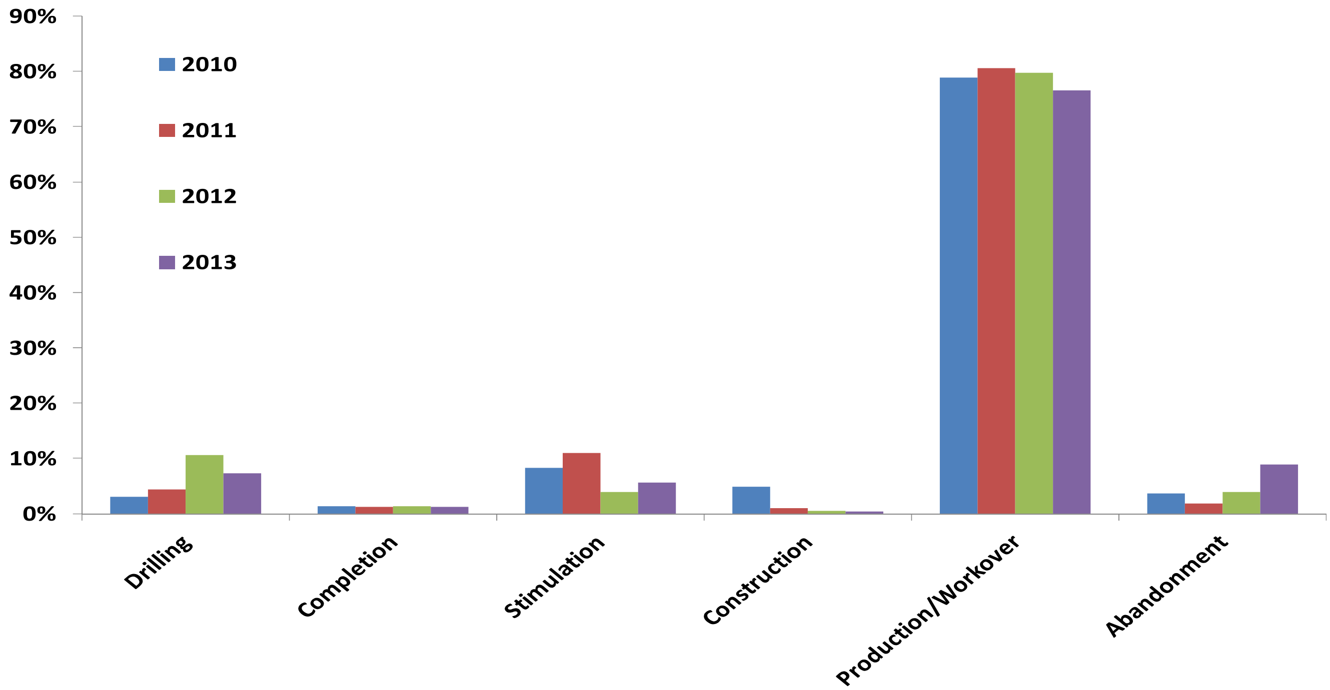
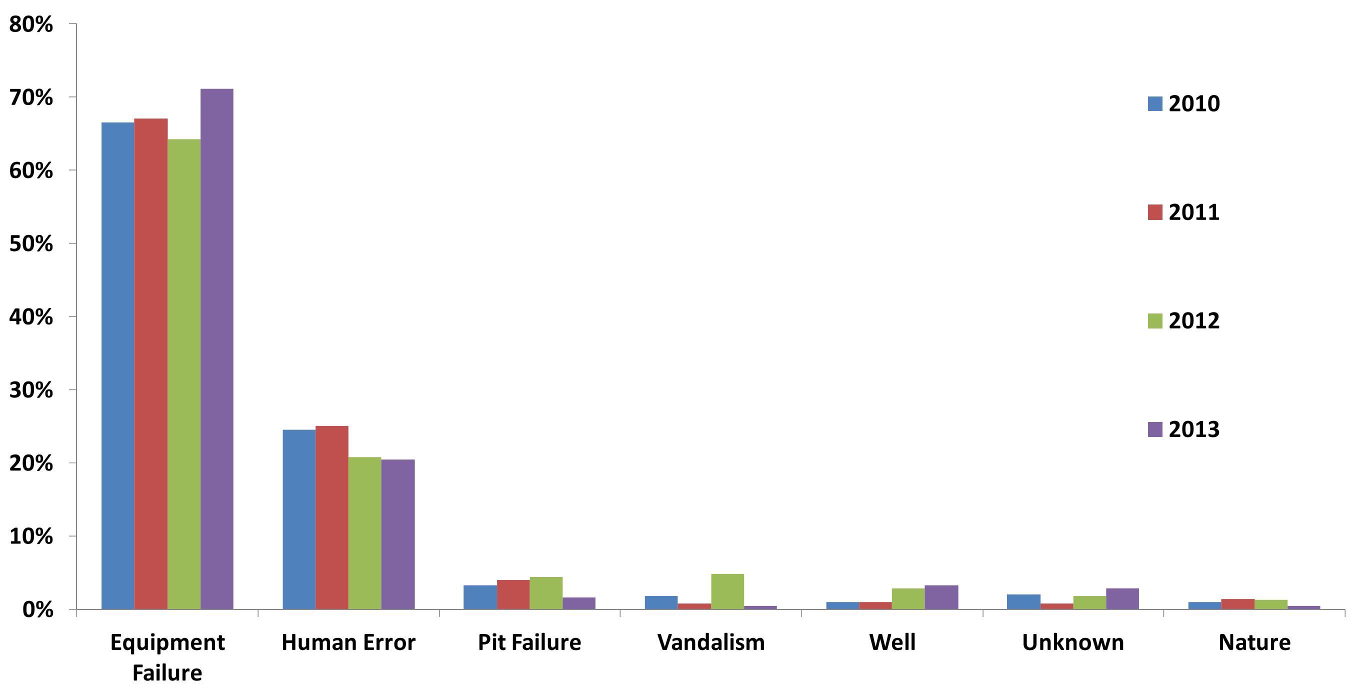


Figure 4-2: Release Causes by Year (Percent of Total)



This analysis provided confidence that the Commission's data set was adequate to identify the operational phases most likely to have a spill or release in the future.

Key Spill Data Results

Data analysis showed that spills and releases are most likely to occur during the *production* phase of oil and gas development. These spills and releases occur at production facilities such as tank batteries. In contrast, oil and gas wells experience relatively few spill or releases during the production phase.

Significantly, only eight percent of spills occur during hydraulic fracturing and only six percent occur during drilling. A brief summary of spill data per operational phase is outlined in **Figure 4-3**.

Figure 4-3: Spill Frequency by Phase

Operational Phase	Count of Reported Spills	Percent of Count
Production	1,277	78%
Stimulation	125	8%
Drilling	96	6%
Abandonment	73	4%
Construction	32	2%
Completion	21	1%
Workover	14	1%
Grand Total	**1,638**	**100%**

Based on Form 19 data, equipment failure is the cause of a spill in more than two-thirds of incidents (see **Figure 4-4**). Human error is the cause of the spill in approximately one-quarter of reports.

Figure 4-4: Spill Frequency by Cause

Operational Phase	Count of Reported Spills	Percent of Count
Equipment Failure	1,094	67%
Human Error	379	23%
Pit Failure	57	3%
Vandalism	33	2%
Well	29	2%
Unknown Cause	28	2%
Nature	18	1%
Grand Total	**1,638**	**100%**

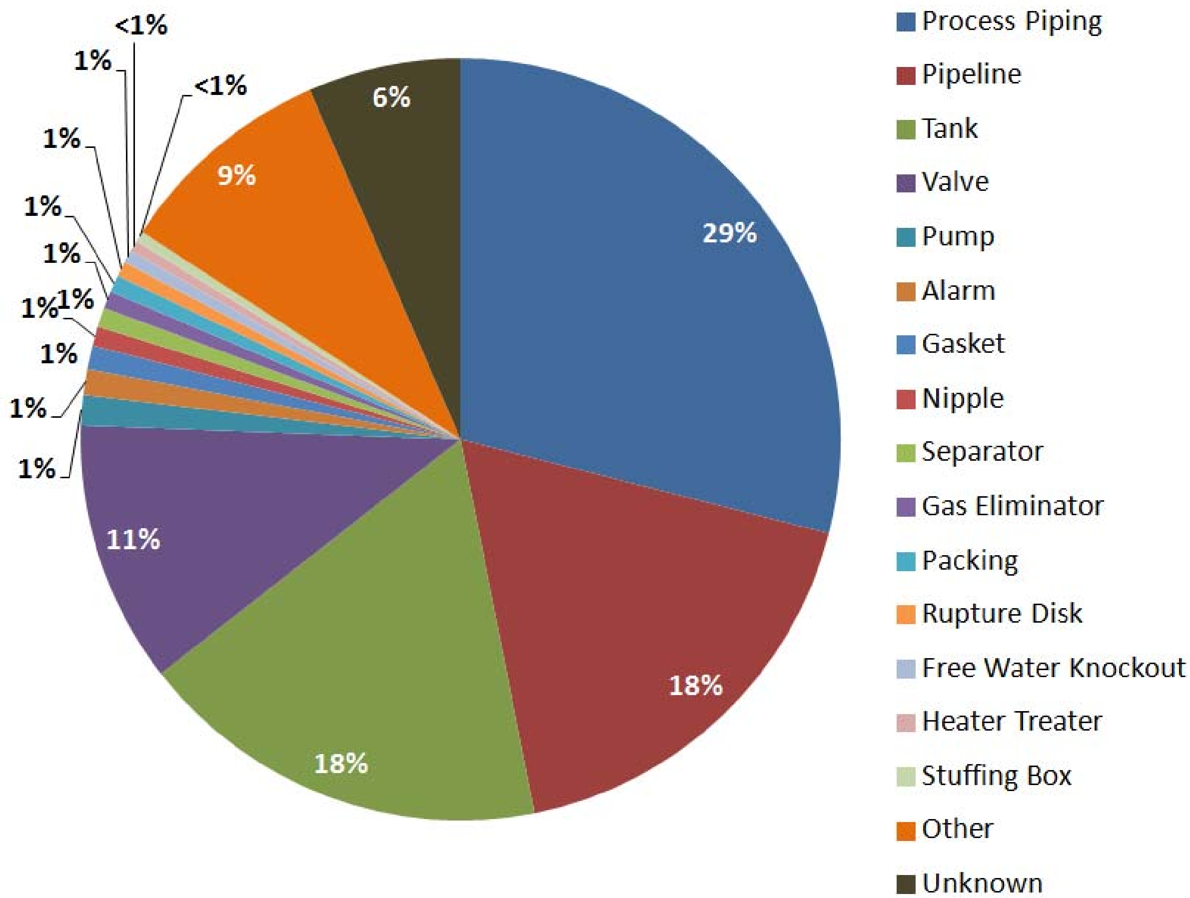
Equipment Failure

Equipment failure is one of the top causes of a spills or releases across all operational phases. Spill reports recorded the failure of approximately 200 different pieces of equipment.

Significantly, however, and as shown in **Figure 4-5**, nearly 75 percent of all equipment failures are of the following four types:

- ► Process piping
- ► Pipelines
- ► Tanks/vaults
- ► Valves.

Figure 4-5: Spills by Equipment Type (Percent of Total)



In the production phase of operations, process piping and pipelines account for half of all spills caused by failed equipment.

Human Error

Failure to check equipment is the most common human error resulting in a spill (58 percent). Overfilling (23 percent) and inadequate training (11 percent) are the next most common human causes of spills.

Human error is four times less likely to be the cause of an incident than equipment failure during the production phase. Nevertheless, human error is only slightly less frequent than equipment failure as the primary cause for all other phases of operation.

Historical Spills

Spills that are discovered after the spill or release occurred and during unrelated activities are referred to as *historical spills*. In most of these cases (82 percent), the cause is equipment failure. Failure of water vaults and process piping are the most frequently cited causes of historical releases.

Vandalism

Data showed that about 2 percent of the spills are caused by vandalism. However, these spills account for half of the largest oil spills in the data set.

Policy Implications

The highest risk of a spill or release was associated with production facilities where natural gas, condensate or crude oil, and produced water is transferred, separated, or stored. Within the production phase, equipment failure is the largest single source of spills and releases.

The four major pieces of equipment that most frequently fail are process piping, pipelines (flowlines), tanks (including partially buried and buried vaults and vessels), and valves. Process piping and vaults are often underground, making identification of non-catastrophic releases or spills difficult to detect. Production facilities may operate in Colorado for years or decades, increasing the likelihood of spills or releases over the lifetime of the facility.

The drilling and stimulation phases (hydraulic fracturing) of oil and gas operations account for less than 20 percent of all spills.

Commission Staff Interviews

During the interview process, Commission inspection staff repeatedly identified Production/Workover as the operational phase most likely to cause spills, releases, or impacts to the environment. Drilling and Stimulation was second (see **Figure 4-6**). Interviewees chose the number of phases they wished to rank and were not required to rank all seven phases shown in the figure.

Staff also pointed to equipment failure and human error as likely causes of spills and releases. Interviewees indicated that, in many cases, equipment failure is another form of human error due to lack of maintenance, poor design, or lack of planning.

Figure 4-6: Commission Inspection Staff Assessment of Phase Risks

	Number of Staff Reporting Phase Ranking for Likelihood to Cause Environmental Impact							
Operational Phase	1st	2nd	3rd	4th	5th	6th	7th	**Rank Sum**
Drilling	2	1	1	2	0	0	1	**7**
Completion	1	1	1	1	0	0	0	**4**
Stimulation	2	3	2	0	0	1	0	**8**
Construction	0	1	1	2	1	0	0	**5**
Production/Workover	6	3	3	3	2	2	0	**19**
Abandonment	0	1	0	0	0	0	0	**1**
Other	0	0	1	0	0	0	0	**1**

Remediation Data

As a test case for how accurately operator-supplied spill report data reflects causes of actual spills, the Commission's outside consultant analyzed three years (2011-2013) of remediation projects from a single operator. The operator is in the process of upgrading facilities recently acquired from another company. From January 2011 through October of 2013, this operator reported 101 spills in three counties, with the majority of spills in Weld County.

Of the 101 total spills, 61 were recorded as equipment failure, 21 were historic releases (also generally a result of equipment failure), seven resulted from human error, five resulted from the flood events of September 2013, and seven were caused by a wave of vandalism. Approximately 60 percent of the spills were attributed to concrete vaults, partially buried tanks, leaking dump lines, production piping, and flowlines.

4.2 Effectiveness of Existing Commission Programs

The Commission inventoried (i) current field inspection policies and practices and (ii) associated regulatory programs to document all Commission systems in place for managing the risks identified in the data collection process explained above.

The Commission then identified gaps in existing programs where modifications could be made to more efficiently and effectively address the highest risk phases of oil and gas operations. The changes or modifications focused on the inspection program but also identified areas where additional interaction with other Commission work groups is required to effect the needed changes.

Systems in Place

The Commission has a framework of comprehensive rules, a robust inspection program, and work units staffed with professional engineers, scientists, and technicians. Commission staff is supported by a highly rated database system. These people and systems are active in each oil and gas development phase, working to reduce risks to public health, safety, and welfare, in addition to the environment.

Well Integrity

Wellbore integrity is the technical term for operational and organizational solutions that reduce risk of an uncontrolled release and or unintended movement of fluids during the life cycle of a well (API RP-90).

The Commission has several rules, policies, and procedures that contribute to confidence in wellbore integrity. The Commission has an active wellbore review process that includes pre-construction permitting and post-construction reporting requirements. Engineering staff completes a pre-construction review of the casing and cement design to verify that the wellbore will isolate fresh water from hydrocarbons. Random and unannounced field inspections are conducted during the drilling and completions phase to monitor and observe the drilling and completion phases.

Post construction, engineering staff review data from the constructed casing and cement to verify that the drilling permit was followed and fresh water and hydrocarbons zones were isolated. Wellbore integrity is monitored throughout a well's productive life with bradenhead and mechanical integrity testing, as well as field inspections. Commission Rules applicable to wellbore integrity are included in **Appendix C**.

The Commission's current inspection processes emphasize drilling and casing inspections to reduce risk associated with well integrity. The Commission's Form 42 Notification assists field inspectors in identifying sites that have scheduled drilling, casing, or hydraulic fracturing activities. A Form 42 filing by an operator triggers an email alert to the inspector, who then can review the location data file and schedule an inspection as necessary.

Hydraulic Fracturing

Hydraulic fracturing is the process of creating small cracks, or fractures, in deep, underground hydrocarbon-bearing formations in order to liberate oil or natural gas and allow it to flow up the well for capture. The technique allows oil and gas to seep from the rock into the pathway, up the well, and to the surface for collection.

In Colorado, the targeted formations for hydraulic fracturing are often more than 7,000 feet underground, and some 5,000 feet below any drinking water aquifers. The process of hydraulic fracturing has been used for decades in Colorado, dating back to the 1970s.

Hydraulic fracturing is now standard for virtually all oil and gas wells in Colorado and across much of the United States. Hydraulic fracturing has made it possible to take oil and gas out of rocks that were not previously considered to be economic sources of fossil fuels. Hydraulic fracturing processes continue to be refined and improved.

The Commission has a significant set of rules and policies regarding hydraulic fracturing operations (for a listing of these items, see **Appendix C**). First, the Commission requires all wells to be cased with multiple layers of steel and cement to isolate fresh water aquifers from the hydrocarbon zone and the hydraulic fracture treatment. Prior to hydraulic fracturing, the well casing must be pressure tested with fluid to the maximum pressure that will ever be applied to the casing. Also, operators follow a notice process to alert field inspectors 48 hours prior to hydraulic fracturing operations. Both processes have reduced the risk of this operational phase of oil and gas development.

Location Assessment

In 2008 the Commission enacted Rule 305, requiring new Oil and Gas Locations to be approved and permitted. Commission environmental protection specialists review every application for a new oil and gas location (Form 2A). This review ensures that the potential impacts from all surface operations, including construction, storm water management, and production facilities, on environmental receptors (such as groundwater, surface water, and wildlife habitat or corridors), have been avoided or mitigated. This location permitting process creates facility identification information in the Commission's database and Geographic Information System (GIS) and records the environmental site conditions for future reference.

In addition to careful review by Commission environmental staff, the Form 2A review process provides for public and local government comment, and, in some circumstances, consultation with Colorado Parks and Wildlife or the Colorado Department of Public Health and Environment. Based on all the information reviewed, the Director of the Commission may apply site-specific COAs to the permit as deemed necessary to avoid, minimize, or mitigate potential impacts to public health, safety and welfare, or the environment, including wildlife. The Commission's inspection data tools link to location permit information, giving field inspectors an important role in verifying operator compliance with permit COAs and Best Management Practices (BMPs).

Control of Air Emissions

The Department of Public Health and Environment's Air Pollution Control Division (APCD) is the primary authority in Colorado for controlling air emissions pursuant to the federal Clean Air Act and Colorado Air Quality Act. However, several Commission Rules relate to air emissions (see **Figure 4-7**) and compliment the APCD programs and staff.

Commission field inspectors are trained to identify air emission issues. Field inspectors routinely take odor control and opacity training and certification courses, and fourteen current staff members are certified in use of Optical Imaging Cameras. Commission staff also conduct joint training and field inspections with APCD staff and coordinate on enforcement issues.

A routine Commission inspection includes review of thief hatches, a potential significant source of VOC emissions, and evaluation of the operational status of emission control devices and production equipment. Information concerning the status of these potential air emission sources is included on the site inspection report and, if problems are identified, the Commission sends a corrective action report to the operator. The Commission also supplies this data to the APCD oil and gas team.

Commission rules regulating oil- and- gas- related air pollution are shown below in **Figure 4-7**.

Figure 4-7: Commission Air Pollution Rules

Rule	Application
324A.c.	Operators shall be in compliance with APCD regulations and standards
604.c(2)C	Green completion emissions
605.a.(9)	Thief hatches and gauges
805	Odor control: crude oil and condensate tanks
805	Green completions

Gap Analysis

The following potential gaps were identified in the Commission's current field inspection policies and practices, and associated regulatory programs. These gaps focused on the operational phases of oil and gas exploration and production that present the highest risk of spills or releases to the environment.

Production Facility Operation and Maintenance

The Commission's safety regulations (600 series) include requirements that valves, pipes, and fittings be maintained in good mechanical condition, and that the operator inspect the equipment at regular intervals. The rules also require production equipment to be properly designed, constructed, installed and, operated to safely contain oil and gas products. However, the Commission does not routinely review operator inspection records, integrity tests, or maintenance records. The Commission also does not provide guidance or procedures to industry to ensure that operational best management practices (BMPs) are implemented. Standardized operation and maintenance, inspection, and testing procedures are techniques that can reduce and mitigate spills.

Flowlines

The Commission identified flowlines as a significant source of spills and releases. The Commission has a set of rules regarding flowline installation, operations, maintenance, and abandonment, but the Commission does not conduct frequent inspections of this equipment or monitor compliance with these rules.

Current field operations staff have limited experience in the operation and maintenance of petroleum pipeline systems.

Currently, there is no requirement for operators to report results of integrity testing of these facilities.

Buried Infrastructure and Site Closures

Commission Rules require that pits, partially buried vessels, and buried vessels follow a closure process, but these rules have not been applied to a site's entire range of production infrastructure. Spill report data indicates that equipment such as process piping and storage tanks, if not maintained, carries a risk of environmental impacts. Operators are presently not required to provide notice of site closure to Commission staff.

Construction, Reclamation, and Drilling Activity Oversight

The Commission conducts a detailed review of oil and gas locations for environmental sensitivity and may add a condition of approval that requires the operator to provide notice of construction activities to the Commission. However, currently notices are sent to Commission Oil and Gas Location Assessment (OGLA) staff and not the field inspector.

Dust, tracking materials onto roads, and stormwater erosion are issues that often result in complaints and can impact public health, safety, and welfare, but also the environment and wildlife resources. Due to the current Commission reliance on complaints, the current inspection process for these activities is reactionary.

Reclamation activities can create the same general issues. The Commission's current inspections are generally conducted after earth moving and construction is completed, rather than at the time of the on-site work. The OGLA review process has not targeted earth-moving activities associated with reclamation for notice.

Hydraulic Fracturing

Increased inspections during hydraulic fracture stimulation operations are warranted due to an elevated level of public concern about the practice. This phase also has the potential to generate noise, dust, odors, and lighting complaints submitted to the Commission. Even though the Commission responds promptly to these complaints, the level of public concern remains high. For this reason, the Commission needs a consistent approach to time-specific, proactive inspections of hydraulic fracturing operations when located in sensitive areas.

Spill Reporting Documentation

SSPA identified gaps in the Commission's Form 19 Spill Report. The Form 19 is being converted to an electronic online format and additional data fields are being added to improve capture and tracking of information about spills.

Geographic Information System Data Layers

Potential impacts to public health, safety, welfare, and the environment can be significantly influenced by natural features and proximity of oil and gas operations to the public. These potential impacts can be narrowed and targeted by use of additional GIS data layers that highlight high risk areas for Commission permitting and inspection personnel.

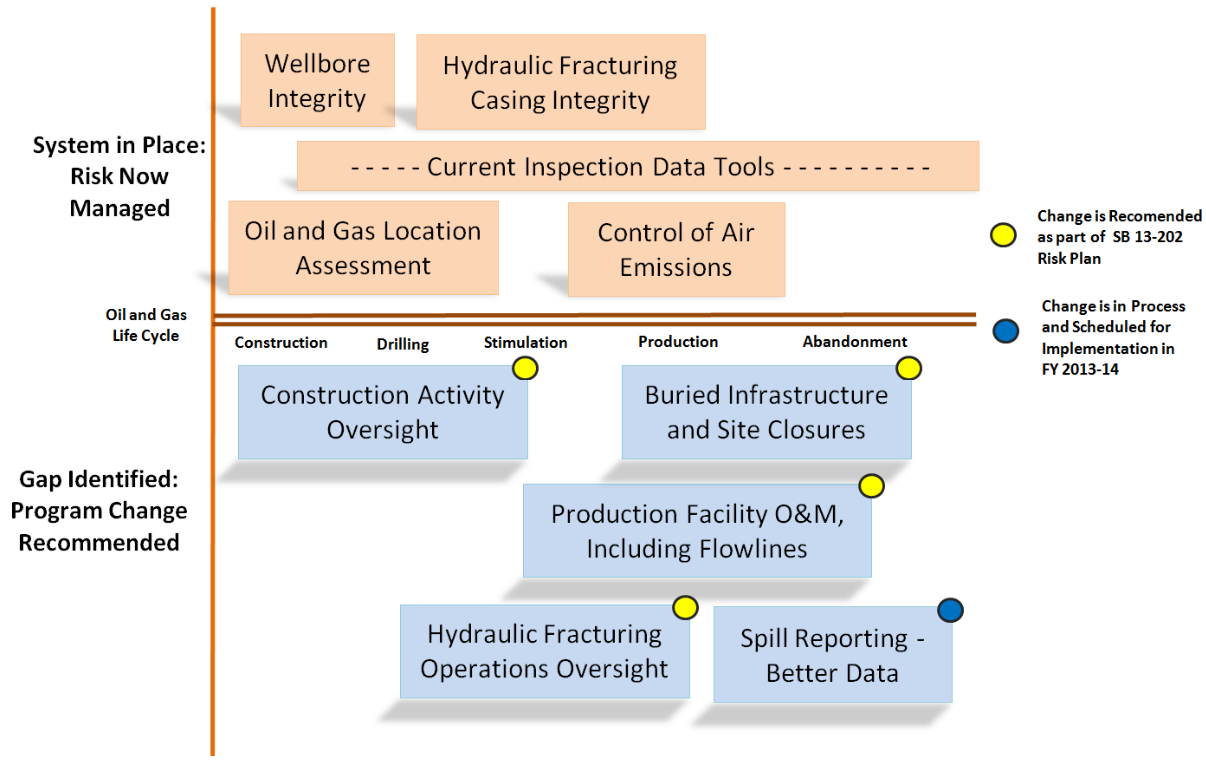
As an example, areas with groundwater used as drinking water supply could be targeted for more frequent or detailed inspections. A GIS tool, based on meteorological data layers, could identify lists of production facilities for Leak and Detection Repair (LDAR) and other inspections targeting air pollution compliance.

Summary

The Commission created a roadmap of options for beneficial changes to its inspection program. **Figure 4-8** summarizes this work.

In the upper portion of the figure, the Commission identified existing systems that are effectively managing environmental risks associated with specific phases of oil and gas operations. In the lower portion, the Commission identified areas in which improvements to existing field inspection and associated regulatory practices are recommended to better manage environmental risks related to particular oil and gas operations.

Figure 4-8: Plot of Risk Management Systems in Place and Commission Opportunities



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CHAPTER 5: RISK MANAGEMENT PLAN

This chapter presents the Commission's findings and risk-based recommendations for addressing the gaps identified in the Commission's regulatory programs. Taken together, these changes will more effectively manage risk from all operational phases of oil and gas development.

5.1 The Commission's Findings

The Commission makes eight findings related to the risks posed by oil and gas operations in Colorado.

Finding One: Highest Risk Operational Phase

Spills and releases are most likely to occur during the production phase of oil and gas operations in Colorado.

The risk is highest at production facilities where natural gas, crude oil, and produced water are separated, treated, and stored in above-ground tanks and sub-grade vaults or vessels.

Movement of fluids in the production phase occurs in complex process piping that is usually buried below the ground surface. For the inspector, instantaneous equipment failure is often observable at the surface, but the greater risk is that aging or improperly maintained subsurface equipment, such as pipelines, may leak. Operators often identify these subsurface problems long after they occur, during activities such as facility upgrades or closure.

Production facilities can be in service for many decades and may be operated by several different companies throughout an oil and gas location's lifecycle. While current Commission engineering review reduces the risk of wellbore failure, production phase process piping, tanks, pipelines, and valves do not currently have similar rigorous systems in place to reduce risk.

Finding Two: Inspection of Production Facilities

Spills and releases that occur subsurface may not be identified during the normal inspection process.

Production facility equipment has been shown to be a significant cause of spills and releases. However, inspectors do not conduct subsurface investigations. Production facilities involve a complex series of buried piping and other equipment that may be pressurized or be constructed of plastic or fiberglass. Intrusive investigation techniques present a significant risk to public health, safety, welfare, and the environment.

The Commission does not have the equipment or staffing available to conduct these complex and high-risk tasks, and conducting routine subsurface investigations as an inspection process is not efficient or effective. Subsurface investigations require detailed planning and logistical work, as well as a detailed knowledge of hydrogeology. The use of subsurface investigations is unlikely to reduce spills and would be infeasible for identifying historical, small scale, or subsurface releases on a large-scale basis.

Finding Three: Production Facility Operation and Maintenance

The Commission does not routinely review production facility maintenance records.

The Commission's safety regulations (600 series) include requirements that valves, pipes, and fittings be maintained in good mechanical condition and that they be inspected on regular intervals. The Rules also require that production equipment be properly designed, constructed, installed, and operated to contain materials safely. However, the Commission does not routinely review operator integrity tests, or inspection and maintenance records.

The Commission does not provide guidance or standard operating procedures to industry to ensure that these BMPs are completed.

Finding Four: Flowline Program Needs Improvement

The Commission should monitor the installation and operation of flowlines.

Flowlines, which are generally buried pipelines that run from a producing well to separation or storage equipment, have been identified by the Commission as a significant cause of spills and releases to the environment.

Integrity testing of flowlines is required by Commission Rule at the time of construction and on an annual basis, but the agency does not have a formal program to monitor ongoing compliance with this regulation. Flowlines are inspected only upon receipt of a complaint or an operator's Form 19 spills and releases report – inspections are not routinely conducted during installation or operation of flowlines.

Finding Five: Facility Site Closure Review

Historic spills from oil and gas operations must be identified and remediated during facility site closure review.

Both the spills report data and remediation plan data show that historic spills – those that occurred at some earlier point but were not identified until closure or modification of the facility – present risks to the environment. Failure of sub-grade equipment, such as process piping, is identified as cause of many of the historic spills or releases. Releases that occur over a long period from sub-grade equipment can be difficult to identify.

Site inspections during facility closure currently are not a priority for inspection staff. Inspections now occur upon receipt of a complaint or by request from other Commission staff.

Operators are not required to provide notice of site closure activities. Absent this information, the Commission cannot plan or schedule inspections to witness these events.

Finally, Commission rules require that pits and partially buried vessels be closed in accordance with a site investigation and remediation plan, but process piping, buried valves, and other equipment are not covered under this requirement.

Finding Six: Construction, Reclamation, and Drilling Activity Inspection Priority

The Commission should receive notice of construction, reclamation, and drilling activities.

The current Commission inspection program does not emphasize same-day inspections of construction activities. Construction or other earth-moving activities during other phases may increase risks of impacts from dust, stormwater erosion, noise, and traffic. These are often nuisance issues that impact nearby residents and property.

Finding Seven: Hydraulic Fracturing Notice

The Commission's systems in place reduce risk from this phase, but public concern remains high.

The Commission has a significant body of rules and policies that regulate hydraulic fracturing operations, including significant engineering controls and environmental management regulations. However, this phase has the potential to generate significant numbers of noise, dust, odors, and lighting complaints from the public. The Commission needs a consistent approach to time-specific, proactive inspections of hydraulic fracturing operations when located in sensitive areas.

Finding Eight: Enhanced Spill Reporting Documentation

The Commission's Form 19 is being improved by standardizing data entry and reporting requirements.

The Commission is making its Form 19 available in electronic form on the Commission website to give operators a more reliable and simple process for giving notice within 24 hours of spills of one barrel or greater. The revised form will standardize data entry and will require additional information on the cause of the spill. The revised form will be released during the first quarter of 2014.

5.2 The Commission's Recommendations

The Commission recommends four changes in its inspection processes in order to better manage the risks associated with each operational phase of oil and gas development (see **Figure 5-1**). The four recommendations are described in summary form in the next section. Each recommendation is accompanied by an estimate of State fiscal impact.

Figure 5-1: How the Recommendations Address Different Oil and Gas Development Phases

		Phase				
Recommendation		Construction	Drilling	Stimulation	Production	Abandonment
1	**Review Integrity Test Results and Inspect Production Facilities More Frequently**				✓	
2	**Increase Inspections During Production Facility Closures**					✓
3	**Conduct More Time-Specific Inspections of Construction, Reclamation, and Drilling Activities Using Improved Notice from Operators**	✓	✓		✓	
4	**Increase Inspection Frequency of Hydraulic Fracturing Operations**			✓		

As shown in **Figure 5-2**, none of the Commission's recommendations require new or amended statutes or rules. Three of the recommendations can be implemented through Commission guidance and policy following a period of stakeholder outreach. Two of the recommendations encompass program modifications significant enough to require appropriations for a limited number of new inspection and engineering staff.

Figure 5-2: How Recommendations Would Be Implemented by the Oil and Gas Conservation Commission

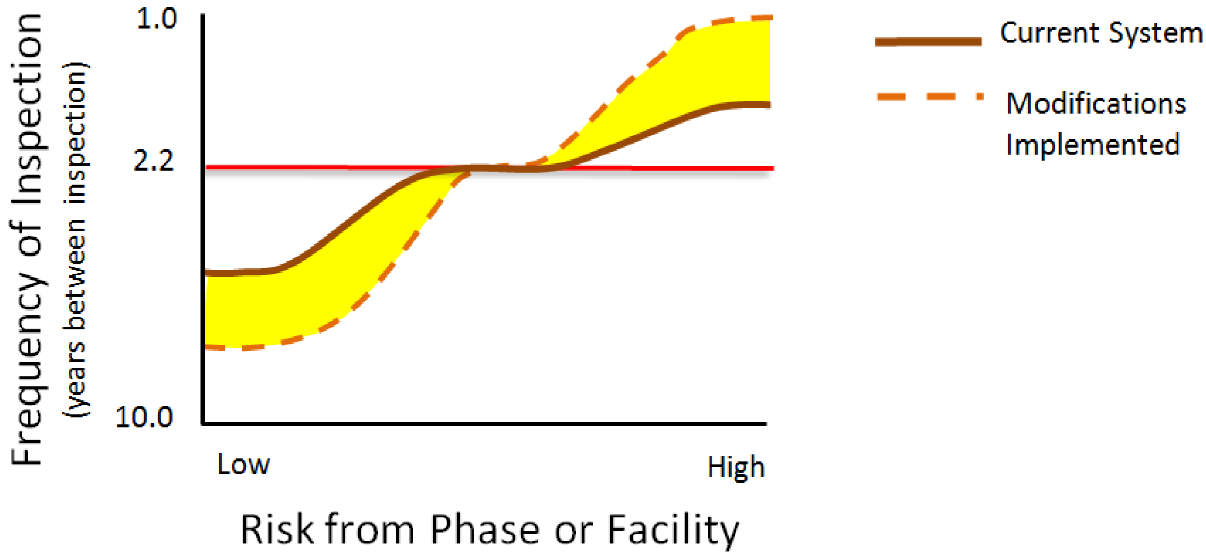
		Scope of Proposed Change			
Recommendation		Statute	Rule	Policy	New Appropriations
1	**Review Integrity Test Results and Inspect Production Facilities More Frequently**			✓	✓
2	**Increase Inspections During Production Facility Closures**			✓	✓
3	**Conduct More Time-Specific Inspections of Construction, Reclamation, and Drilling Activities Using Improved Notice from Operators**			✓	
4	**Increase Inspection Frequency of Hydraulic Fracturing Operations**				

The expected long-term result of implementation of the Commission's recommendations is a shift in inspection priority. Lower risk facilities or phases would receive less frequent inspections, and higher risk facilities or phases would receive incrementally more frequent inspections.

Figure 5-3 illustrates the concept of lowering the frequency of low-risk facility or phase inspections (from the brown line to the dashed orange line) and increasing the number of high-risk facility or phase inspections (from the brown line to the dashed orange line). Current inspections occur on average each 2.2 years (shown as the red line), based on Fiscal Year 2012-13 data.

The Commission may expend less inspector effort in the yellow area on the left side, representing inspections that will be performed less frequently, and place additional effort in the yellow area on the right side, representing inspections that will be done more frequently. The resulting shift in inspection resources will reduce oil and gas impacts to air, surface water, groundwater, and soil.

Figure 5-3: Impact of Recommendations on Inspection Frequency



Recommendation One: Review Integrity Test Results and Inspect Production Facilities More Frequently

Production facility equipment failure is the most common cause of oil and gas spills and releases. Many of the incidents occur below ground, and standard screening cannot identify these subsurface releases. Moreover, intrusive sampling is not a practicable or reliable inspection method. Preventing incidents through maintenance, monitoring, and testing can reduce the incidence of equipment failure.

The Commission should inspect production equipment more frequently, require operators to regularly report integrity test results for production infrastructure, and retain maintenance records for review by Commission staff. Best practices should focus integrity testing upon key events in the oil and gas lifecycle, including facility construction, facility maintenance, and major modification to the site. Testing should occur otherwise at periodic intervals.

This recommendation for the Commission's inspection program would target the production facilities posing a risk to surface water, groundwater, soil, and air quality. This infrastructure includes tanks, vaults, sumps, process piping, separation equipment, and related valves and fittings. The producing well itself is not targeted in this recommendation, because the Commission's systems in place focus on wellbore integrity and reduce the risks of wellbore failure.

If not properly maintained, flowlines also pose risks to the environment, and the testing requirements should also apply to flowline infrastructure. Because pipeline safety expertise does not now exist within the Commission, the Commission would need to hire a small number of new engineering and inspection staff to focus on the risk posed by flowlines.

To implement this recommendation, the Commission would issue new guidance and policy to operators to establish production equipment testing procedures, immediate reporting of failed tests, submission of maintenance records, and periodic test data. Inspectors would be present for key construction and maintenance events, and new staff skilled in interpretation of integrity test results would give priority to infrastructure that fails important tests.

As an expansion of the Commission's existing inspection program, the change would require stakeholder outreach and discussion, software modification, and legislative appropriations to fund new personal services and operating costs.

Budget Requirements

Cash fund appropriations from the Oil and Gas Conservation and Environmental Response Fund of $327,200 in the first year and $301,900 each year thereafter would fund implementation of this proposed modification to Commission programs. One engineer and two technicians would be added to the Commission under this proposal. Approximately $50,000 in database programming costs are also anticipated. The schedule for this recommendation includes nearly twelve months of stakeholder outreach, process design, and database work that would allow improved response to maintenance at production facilities statewide by the start of FY 2015-16.

Figure 5-4: Recommendation One At A Glance / Fiscal Impact

Recommendation	
Number	One
Name	*Review Integrity Test Results and Inspect Production Facilities More Frequently*
Policy Focus	
Oil and Gas Phase	Production
Scope of Regulatory Change	Add Capacity to Existing Program
Fiscal Impact	
FTE Change	3.0
First Year Personal Services Impact (FY 2014-15)	$210,800
First Year Operating Impact (FY 2014-15)	83,600
First Year Leased Space (FY 2014-15)	29,800
First Year State Vehicle Lease (FY 2014-15)	3,000
Total First Year Cost (FY 2014-15)	**$327,200**
Ongoing Annual Personal Services Impact	$231,700
Ongoing Annual Operating Impact	21,000
Ongoing Annual Lease Space	44,600
Ongoing Annual State Vehicle Lease	4,600
Total Ongoing Annual Cost	**$301,900**

Recommendation Two: Increase Inspections During Production Facility Closures

When operators wish to abandon oil and gas locations at the end of the facility's life cycle, the Commission should require operators to provide the Commission with a Notice of Closure. Such a notice would allow Commission inspectors to be on site during critical closure activities. In this way, the Commission's inspectors could better manage risks to soil, surface water, and groundwater from aging and abandoned facilities.

For site closure activities in environmentally sensitive areas or where spills or releases have occurred, the Commission would require an operator to submit a site closure plan. This plan would include environmental sampling and analysis for partially buried vessels, sumps, tanks, and process piping.

Without a need to amend its statute or rules, the Commission could implement this recommendation by issuing new guidance and policy to operators after a period of stakeholder outreach. Subject to new legislative appropriations, the Commission would accelerate the conversion of site closure forms from a data-entry intensive process to an online electronic format for the benefit of operators, and develop database modifications to facilitate Commission staff review of operator plans and data.

Because current staff resources in the Commission's environmental program are insufficient to process and coordinate follow-up from these site closure submissions, new funding for a limited number of staff would also be required.

Budget Requirements

Cash fund appropriations from the Oil and Gas Conservation and Environmental Response Fund of $109,600 in the first year and $70,800 per year on an ongoing basis would fund implementation of this proposed modification to Commission programs. One technician would be added to the Commission under this recommendation. Approximately $40,000 in database programming costs are also anticipated. The schedule for this recommendation includes nearly twelve months of stakeholder outreach, process design, and database work that would allow improved response to site closures by the start of FY 2015-16.

Figure 5-5: Recommendation Two At A Glance / Fiscal Impact

Recommendation	
Number	Two
Name	*Increase Inspections During Production Facility Closures*
Policy Focus	
Oil and Gas Phase	Abandonment
Scope of Regulatory Change	Add Capacity to Existing Program
Fiscal Impact	
FTE Change	1.0
First Year Personal Services Impact (FY 2014-15)	$60,300
First Year Operating Impact (FY 2014-15)	49,300
Total First Year Cost (FY 2014-15)	**$109,600**
Ongoing Annual Personal Services Impact	$66,300
Ongoing Annual Operating Impact	4,500
Total Ongoing Annual Cost	**$70,800**

Recommendation Three: Conduct More Time-Specific Inspections of Construction, Reclamation, and Drilling Activities Using Improved Notice from Operators

To better manage risks from dust and stormwater across the entire lifecycle of oil and gas operations, the Commission should ask operators to file Notices of Construction Activity, Site Reclamation Activity, and Move In Rig Up in sensitive areas. The notice requirements would be developed during the permitting process and target environmentally sensitive locations.

The Commission already requires a Notice of Drilling (or spud) enabling Commission inspectors and engineers to effectively manage the risks posed by drilling. The requirement to provide notice of site construction is also included as a COA on location permits when the Commission's location specialist identifies critical sites. However, the Commission's current system does not provide for notices of other activities that have the potential for significant dust, erosion, or traffic-related issues.

With adequate notice, the Commission would establish a greater presence of field inspectors at specific times in the construction, drilling, and production phases. This recommendation would necessitate a higher level of coordination between Commission permitting, environmental, and inspection work groups.

The Commission suggests several stakeholder outreach events to refine this proposal, circulation of proposed new guidance, and determination of the details of timing and information contained in each notice. No new statutes or rules are needed.

Implementation of this recommendation can be accomplished using existing agency appropriations.

Budget Requirements

To implement this recommendation for the Commission inspection program, no new funding is required. Allowing for stakeholder outreach and process design, new notices from operators and new inspections by the Commission would start by the midpoint of Fiscal Year 2014-15, or January 2015.

Figure 5-6: Recommendation Three At A Glance / Fiscal Impact

Recommendation	
Number	Three
Name	*Conduct More Time-Specific Inspections of Construction, Reclamation, and Drilling Activities Using Improved Notice from Operators*
Policy Focus	
Oil and Gas Phases	Construction, Drilling, and Production
Scope of Regulatory Change	Modify Existing Program
Fiscal Impact	
None.	

Recommendation Four: Increase Inspection Frequency of Hydraulic Fracturing Operations

The Commission should increase the presence of its inspectors during hydraulic fracturing activities in the stimulation phase of operations.

Hydraulic fracturing is a source of significant public concern, and increased inspections would help increase the public's trust in the state's regulatory oversight. The Commission's inspectors would target stimulation activities nearest to urban areas. Nuisance issues such as lights, noise, traffic, and dust could also be addressed. Inspections during flowback after hydraulic fracturing would identify compliance with Commission rules on green completions and supplement Air Pollution Control Division monitoring activities.

The focus of this recommendation is the Commission's inspection program, because the Commission effectively implements an existing system of engineering control of well integrity during the stimulation phase. No new statutes or rules would be needed.

Implementation of this modification can be accomplished using existing agency appropriations.

Budget Requirements

To implement this recommendation, no new funding is required. After a short planning period, inspection managers could reallocate field staff resources by the beginning of Fiscal Year 2014-15.

Figure 5-7: Recommendation Four At A Glance / Fiscal Impact

Recommendation	
Number	Four
Name	*Increase Inspection Frequency of Hydraulic Fracturing Operations*
Policy Focus	
Oil and Gas Phase	Stimulation
Scope of Regulatory Change	Modify Existing Program
Fiscal Impact	
None.	

5.3 Existing Commission Authority

With the exception of Recommendations One and Two, each of which requires legislative appropriations to fund new staff and changes to the Commission database and electronic forms, current statutes and rules are sufficient to implement the Commission's proposed recommendations. Rules for the inspection program currently provide the Commission with authority to receive notice when critical events occur, inspect oil and gas infrastructure, review site closure plans, and enforce maintenance standards. **Figure 5-8** describes the Commission's Rules supporting each recommendation proposed in this chapter.

Figure 5-8: Existing Commission Authority for Recommendations

	Recommendation	Implementing Authority from Existing Commission Rule(s)	
1	**Review Integrity Test Results and Inspect Production Facilities More Frequently**	206	Reports
		605.d	Oil and Gas Facilities - Mechanical Conditions
		605.e	Oil and Gas Facilities - Buried or partially buried tanks, vessels, or structures
2	**Increase Inspections During Production Facility Closures**	204	General Functions of Director
		206	Reports
		909	Site Investigation, Remediation, and Closure
		910	Concentrations and Sampling for Soil and Ground Water
3	**Conduct More Time-Specific Inspections of Construction,**	805	Odors and Dust
		1002	Site Preparation and Stabilization
4	**Increase Inspection Frequency of Hydraulic Fracturing Operations**	316C	Notice of Intent to Conduct Hydraulic Fracturing Treatment

APPENDICES

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APPENDIX A: SENATE BILL 2013-202

This section contains the May 2013 legislation that directs the Commission to evaluate risk management options for Commission regulatory programs.

NOTE: The governor signed this measure on 5/24/2013.

An Act

SENATE BILL 13-202

BY SENATOR(S) Jones, Aguilar, Carroll, Giron, Guzman, Heath, Jahn, Kefalas, Kerr, Newell, Nicholson, Schwartz, Todd, Ulibarri, Morse;
also REPRESENTATIVE(S) Singer, Fields, Fischer, Ginal, Hamner, Hullinghorst, Labuda, Melton, Rosenthal, Ryden, Schafer, Williams.

CONCERNING ADDITIONAL INSPECTIONS OF OIL AND GAS FACILITIES, AND, IN CONNECTION THEREWITH, MAKING AN APPROPRIATION.

Be it enacted by the General Assembly of the State of Colorado:

SECTION 1. Legislative declaration. (1) The general assembly hereby:

(a) Finds that the substantial increase in oil and gas development in Colorado, while very beneficial to Colorado's economy:

(I) Has led to increased risks to Colorado's natural environment and public health; and

(II) Has not been accompanied by a proportionate increase in the inspections staff of the Colorado oil and gas conservation commission;

(b) Determines that:

Capital letters indicate new material added to existing statutes; dashes through words indicate deletions from existing statutes and such material not part of act.

(I) Timely inspections of new and producing oil and gas wells, including those that are hydraulically fractured, are critical to protecting public health, minimizing environmental contamination, detecting spills before they worsen, and ensuring public trust; and

(II) Given the limitations of its current authorization for only sixteen inspectors, the inspection staff of the Colorado oil and gas conservation commission can inspect the more than fifty thousand active wells in Colorado, on average, only about once every four years, with each staff member inspecting more than three thousand wells per year; and

(c) Declares that this act to increase the frequency of inspections of oil and gas wells is necessary for the immediate preservation of the public peace, health, and safety.

SECTION 2. In Colorado Revised Statutes, 34-60-106, **add** (15.5) as follows:

34-60-106. Additional powers of commission - rules - repeal. (15.5) THE COMMISSION SHALL USE A RISK-BASED STRATEGY FOR INSPECTING OIL AND GAS LOCATIONS THAT TARGETS THE OPERATIONAL PHASES THAT ARE MOST LIKELY TO EXPERIENCE SPILLS, EXCESS EMISSIONS, AND OTHER TYPES OF VIOLATIONS AND THAT PRIORITIZES MORE IN-DEPTH INSPECTIONS. THE COMMISSION SHALL:

(a) (I) SUBMIT A REPORT BY FEBRUARY 1, 2014, TO THE GENERAL ASSEMBLY'S JOINT BUDGET COMMITTEE AND THE SENATE AND HOUSE OF REPRESENTATIVES COMMITTEES OF REFERENCE WITH JURISDICTION OVER ENERGY THAT INCLUDES FINDINGS, RECOMMENDATIONS, AND A PLAN, INCLUDING STAFFING AND EQUIPMENT NEEDS.

(II) THIS PARAGRAPH (a) IS REPEALED, EFFECTIVE SEPTEMBER 1, 2014.

(b) IMPLEMENT THE SYSTEMATIC RISK-BASED STRATEGY BY JULY 1, 2014. THE COMMISSION MAY USE A PILOT PROJECT TO TEST THE RISK-BASED STRATEGY.

SECTION 3. Appropriation. In addition to any other appropriation, there is hereby appropriated, out of any moneys in the oil and gas conservation and environmental response fund created in section 34-60-122 (5), Colorado Revised Statutes, not otherwise appropriated, to the department of natural resources, for the fiscal year beginning July 1, 2013, the sum of $100,000, or so much thereof as may be necessary, for allocation to the oil and gas conservation commission for a risk-based inspection study related to the implementation of this act.

SECTION 4. Applicability. This act applies to conduct occurring on or after the effective date of this act.

SECTION 5. Safety clause. The general assembly hereby finds, determines, and declares that this act is necessary for the immediate preservation of the public peace, health, and safety.

John P. Morse PRESIDENT OF THE SENATE	Mark Ferrandino SPEAKER OF THE HOUSE OF REPRESENTATIVES
Cindi L. Markwell SECRETARY OF THE SENATE	Marilyn Eddins CHIEF CLERK OF THE HOUSE OF REPRESENTATIVES

APPROVED

John W. Hickenlooper
GOVERNOR OF THE STATE OF COLORADO

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APPENDIX B: SPILL DATA ANALYSIS

This section contains the S.S. Papadopulos and Associates, Inc. report from November 2013 analyzing filings of 1,638 spill and release (Form 19) reports by operators between January 2010 and August 2013.

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Technical Memorandum

Spills/Release Report, Form 19 Review and Analysis

Prepared for: **State of Colorado Department of Natural Resources, Colorado Oil and Gas Conservation Commission**

Prepared by:

S.S. PAPADOPULOS & ASSOCIATES, INC.
Boulder, Colorado

November 18, 2013

3100 Arapahoe Avenue, Suite 203, Boulder, Colorado 80303-1050 • (303) 939-8880

TECHNICAL MEMORANDUM

Date: November 18, 2013

To: Margaret Ash – Colorado Oil & Gas Conservation Commission

Subject: **Spill/Release Report, Form 19 Review and Analysis**

INTRODUCTION

The Colorado Oil & Gas Conservation Commission (COGCC) has been asked to use a risk-based strategy of inspection that will target the oil and gas operational phases that are most likely to experience spills and create a health risk to the public and environment. For each oil and gas spill reported to COGCC, Rule 906 requires that the responsible party fill out a Spill/Release Report, Form 19. For COGCC, S. S. Papadopulos & Associates, Inc. (SSPA) reviewed 1638 Form 19 spill reports for the period January 2010 through August 2013 in order to determine the locations, causes, and timing of previous spills to assist in forming a risk-based approach for inspections.

METHODS

Data

For the last 20 years, the COGCC has required that spills associated with oil and gas activities that were five barrels (bbls) or greater in volume (or any volume if the spill impacted the State's waters) be reported using a Spill/Release Report, Form 19 (COGCC Rule 906.b). The contents of these forms have been input into the COGCC spills database. (A copy of Form 19 is provided in Appendix 1 and a list of the fields included in the COGCC spills database is provided in Appendix 2.) SSPA was provided with an electronic download of all of the responses contained in the Form 19 spill reports database. These data include a field containing a detailed description of the spill. This detailed description was the basis for most of the categorizations. The COGCC database also includes links to download the original submitted Form 19s. These hardcopy forms were used to supplement the data when the online database was insufficient for categorization. To facilitate analysis, SSPA categorized each spill according to:

- operational phase,
- cause,
- equipment,
- location, and
- size.

A listing of the fields created by SSPA and preserved in an augmented version of the COGCC database is provided in Appendix 3.

Categorization

The primary categorization of spills was based on the operational phase when the spill occurred. In order to analyze which operational phases were most likely to experience spills, the spill reports were separated into operational phase and sub-phase categories. Each spill report was researched to find what operational phase of oil and gas exploration and production was applicable when the spill occurred. The possible operational phases are construction, drilling, completion, stimulation, production, workover, and abandonment.

Similar categorization was done for other possible spill factors. In addition to operational phase, the categories evaluated for each of the 1638 spill reports include the following:

- Reported cause of the spill (e.g., equipment failure, human error)
- Equipment involved if equipment failure was the reported cause (e.g., process piping)
- Location of the failed equipment (e.g., well, pit, separator)
- Size of the spill by volume

Analysis

Once the data were categorized, an analysis was conducted to identify the most common factors characterizing the spills. Pivot tables were created for all of the different categories and many combinations of categories. Discussion of the factors that have the greatest relevance to assessing spill risks is provided below.

FINDINGS

Summary Statistics

There were a total of 1,638 spill records provided from January 2010 through August 2013. Table 1 through Table 5 show basic summaries for the categorized Form 19s. They show spill counts and percentages for each of the categorized fields. Table 1 through Table 4 also show the average spill volume for categorized fields (calculated only for spills where volumes have been reported).[1]

[1] This is the total reported spilled volume for all of the spill reports used for this study. It is important to note that for many historical spills, the spill volume was often unknown and unreported, therefore the total spill volume provided for each category represents a minimum value and the percentages reported may be skewed by the number of spills where no volume was reported.

Details and Trends

- **Operational Phase** – Spills that occurred during the production operational phase accounted for 78% of all reported spills as shown in Table 1 and Figure 1. Following production, the second and third highest phases for spills were stimulation and drilling, at 7.6% and 5.9%, respectively. As also shown in Table 1, the largest average volume for spills occurs during production and stimulation, the two phases with the largest number of spills.
- **Cause** – The reported causes of spills are shown in Table 2. Equipment failures (67%) and human error (23%) were the most reported causes. The upper left of Figure 2 shows a pie chart with the percentage of spills reported for each of the causes. The bottom right of Figure 2 shows the same pie chart but with the equipment failure cause broken out into the equipment that failed and caused the spills.[2]

  Table 6 compares the spills in each of the operational phases with the cause for the spill. The widespread occurrence of equipment failures across all operational phases is apparent in this table, as is the increase in frequency of human error during the drilling and stimulation phases. Table 7 is a more detailed summary of the human error cause. 58% of spills caused by human error were caused by a failure to check the equipment.
- **Equipment Failure** – There were more than 200 different pieces of equipment reported to have failed, but over 75% were identified to be process piping (27%), pipelines (18%), tanks (18%), and valves (11%). Table 3 summarizes the different pieces of equipment reported to have failed; Figure 3 is a bar chart illustrating the preponderance of the four primary pieces of equipment that failed and caused spills most often. (Only pieces of equipment that were reported on at least 5 spill reports are shown in Table 3 and Figure 3.) Figure 4 shows the most common types of equipment involved in releases broken down by operational phase. Of note, during production (including workover), process piping and pipelines are the equipment pieces that account for 50% of all failed equipment.
- **Facility Type/Equipment Failure Location** – The location of spills was often difficult to discern since the facility type listed on the Form 19s varied between actual locations, such as well or compressor station (or non-facility), and equipment type, such as separator or water line. Because of the predominance of equipment failure as a cause for spills, the equipment failure sub-category equipment location was created. Table 4 summarizes the number of spills at the various locations where oil and gas exploration and production occur. The categorization illustrates the ambiguity of the facility type vs. equipment location issue; therefore, it is footnoted to provide better distinction for equipment and

[2] Percentages of each highlighted specific failed piece of equipment in Figure 2 are calculated based on total for all causes, not just equipment failure; hence differ from percentages shown on Table 3.

location. The GAP Analysis section below includes further discussion of this situation.

- **Spill Volume** – Table 5 shows a summary of the spill size by volume. The spill sizes have been grouped into five size categories. This table shows spill size regardless of what was spilled (oil, water, etc.). The five largest water and petroleum spills are listed in Table 8 and Table 9 respectively. The three largest petroleum spills were caused by vandalism. The top five water spills were caused by equipment failures. All were during the production operational phase.

  There were 490 reports where spill size was unknown or left blank on Form 19. Many of these (56%) have been identified as historical releases. For spills not identified as historical, the lack of volume implies that the volume is unknown, but involved at least the minimum amount of hydrocarbon or water required to be reported. The uncertainty involved with spill volumes should be addressed in potential revisions to Form 19.

  Similarly, the Form 19 field of area impacted by spill was not used this analysis; this field was only minimally useful to this analysis because the largest area spills frequently involved misting of materials into the air and did not correlate with volume.

- **Inter-annual Release Variability** – Figures 5a-c show a breakdown of releases by cause, operational phase, and equipment failure detail. With minor exceptions, the relative percentages of causes, operational phase, and equipment for 2010 through August 2013 (prior to the widespread flooding in northeast Colorado) are consistent and do not vary greatly between different years.

Additional Results

- More than half of largest oil spills were caused by vandalism. Even though there were only 33 reports of spills caused by vandalism (out of 1,638 reports), 31 involved releases of hydrocarbons and 19 were greater than 120 bbls. On June 19, 2012, 12 locations were vandalized within a 2-mile radius spilling more than 2,300 bbls of oil; however, even without this incident, vandalism accounted for 35% of the remainder of the oil spills that exceeded 100 bbls. (The two releases of water that were related to vandalism were also very large, 660 bbls in one case and 1154 in the other.) There were only 11 reports of oil spills that exceeded 120 bbls for all of the other causes combined. Of these 11 oil spills, four were due to human error, five were due to equipment failure, and two were due to nature (freezing and lightening).
- As seen in Table 2the two most common causes of failures are equipment failure (67%) and human error (23%). In the production operational phase, equipment failures cause 72% of spills and human errors cause 19% of spills. In all the other operational phases combined, equipment failures account for only 47% of spills while human errors cause 38%. Nature (e.g., freezing temperatures, wildlife,

lightning strikes, and heavy rain) reported as a cause for spills, accounts for only 1% of the spills reported in 2010 through August 2013 (prior to the September flood event); however, equipment failure associated with freezing temperatures was reported 75 times.

- There are 288 spills that have been identified as historical releases (i.e., the spill was discovered after it occurred while other unrelated activities were being conducted). Table 10 is a summary of the cause and equipment failures of the historical releases. 82% of the historical releases were from equipment failures. The most common equipment that failed was water vaults (36%) and process piping (31%). Table 11 is a summary of the locations of the historical releases. The most likely location of a historical release was at a tank (67%) with the second most common being a pit (10%)

GAP ANALYSIS

Form 19 improvements

In working with the data from the Spill/Release Report, Form 19, several areas have been identified as candidates for possible improvements to Form 19 and to the data entry into the database. Overall, since the form can already be completed electronically in Acrobat format, COGCC should consider creating an online form that will allow the use of dropdown menus for selected fields so that uncertainties involved with the type of information to provide can be reduced or eliminated.

In addition, changes to the following fields (including, in some cases, the use of dropdown menus) could increase the quality of data:

- **Type of Facility** – This field should have fewer possible entries and have instructions that indicate what should be entered. The use of drop down menus to limit entries would be valuable for this field. The facility types should be limited to categories such as Well (or Well Head), Well Pad, Pit, Tank Battery, Right-of-Way (e.g., for pipelines located away from wells and processing facilities), Roadway, Processing Plant, Production Plant, Compressor Station, This restriction would help clarify the "location of equipment failure" detail mentioned above in the Details and Trends section.
- **Volume and Material Spilled (1)** – Currently some or all of these fields are left blank. It is suspected that a blank field sometimes represents an unknown volume. Redesigning this portion of the field so that a volume of zero (0) is differentiated from "unknown" would potentially be valuable. In addition, specifically providing a checkbox for Historical spills would also be helpful, and could potentially be incorporated into this portion of Form 19. As with other fields, this portion of Form 19 would be amenable to modification to use dropdown menus.

- **Volume and Material Spilled (2)** – Review of Form 19 for materials spilled indicates that drilling mud, flowback fluids, and hydraulic fracturing fluids are the most common materials involved in spills of materials other than hydrocarbons or water. The use of dropdown menus for sub-categories under “other” would allow tracking of these common spill materials.
- **Area and Vertical Extent of Spill** –This field does not have a uniform format to report the extent of the spill. The forms could require an entry of specific units (e.g., feet-squared) to determine horizontal extent and an individual field for depth (ft). Alternatively, and possibly most simply, include Length (ft), Width (ft), and Depth (ft) as individual fields. Additionally, differentiating with a checkbox or dropdown menu whether the impacted area occurs due to spills of liquid or solid material directly to the ground, or due to result of misting would constrain often anomalous appearing spill extents.
- **Cause of Spill** – COGCC should consider breaking this field into two parts. The first would have a limited number of possible entries such as those shown in Table 2 (that could be provided in a dropdown menu). The second part would be a dialog box allowing the party reporting the spill to provide detailed description of the spill and associated causative factors (currently provided in the COGCC database in the “spill_desc” field).
- **Suggested Additional Fields**
    - Because of the predominance of equipment failure as a spill cause, the addition of a simple field/dropdown box allowing entry of the most common equipment that fails would potentially be useful. In a similar manner, categorization of spills caused by human error would also potentially be useful.
    - Operational Phase could be captured with a simple field/dropdown menu that includes the phases listed in Table 1.

FIGURES

TABLES

APPENDICES

Figures

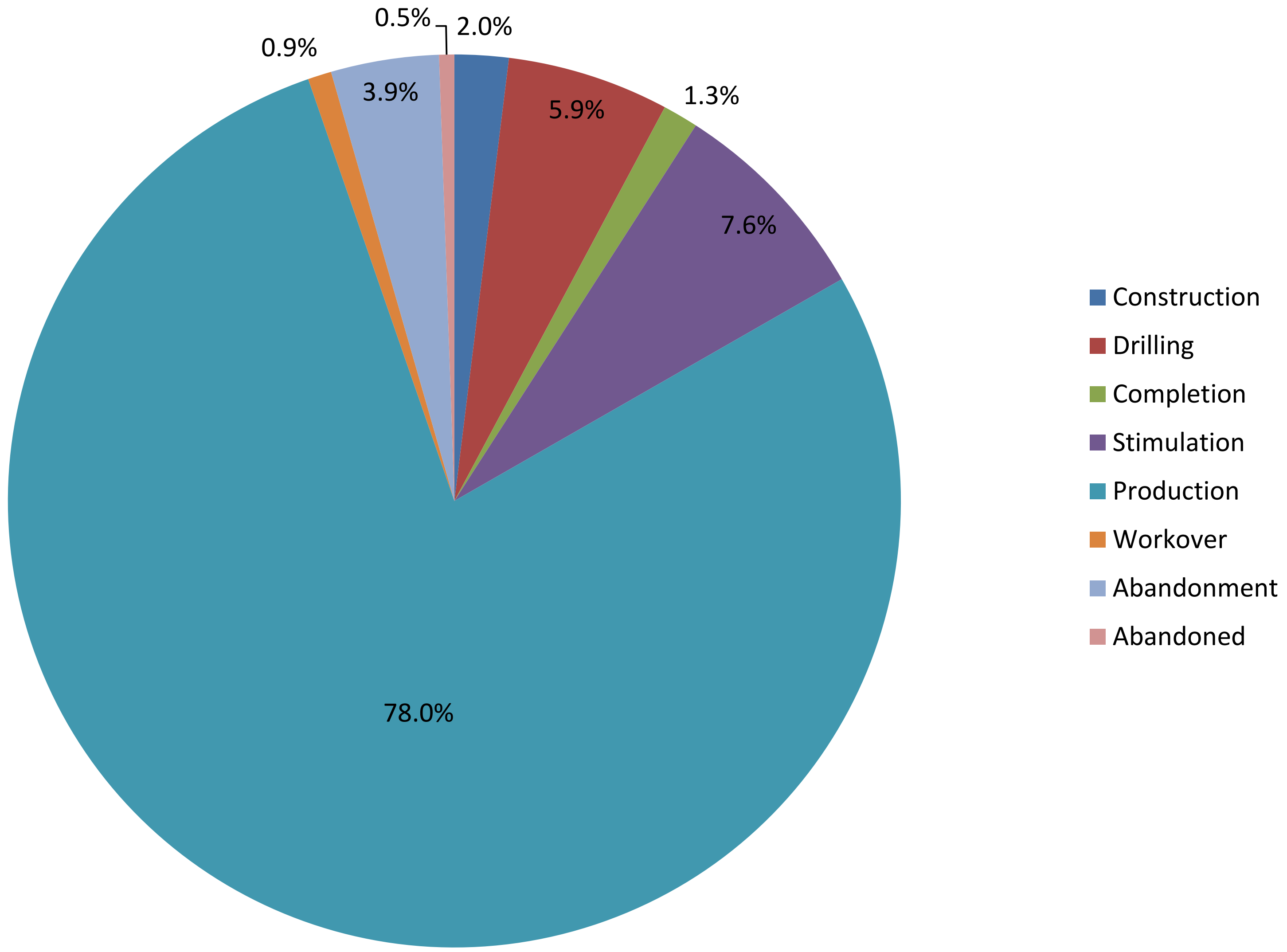


Figure 1. Releases by Operational Phase

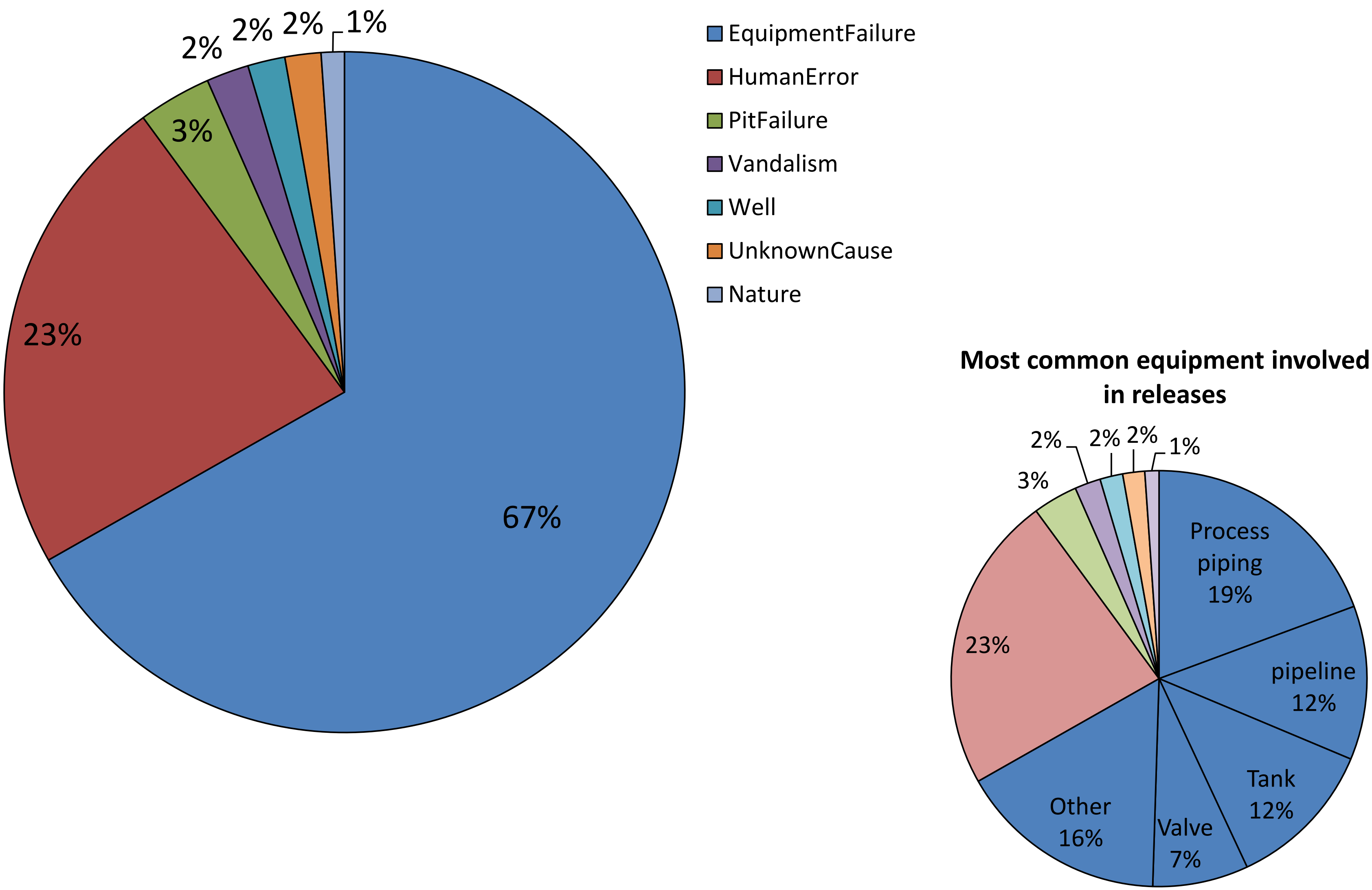


Figure 2. Release Causes

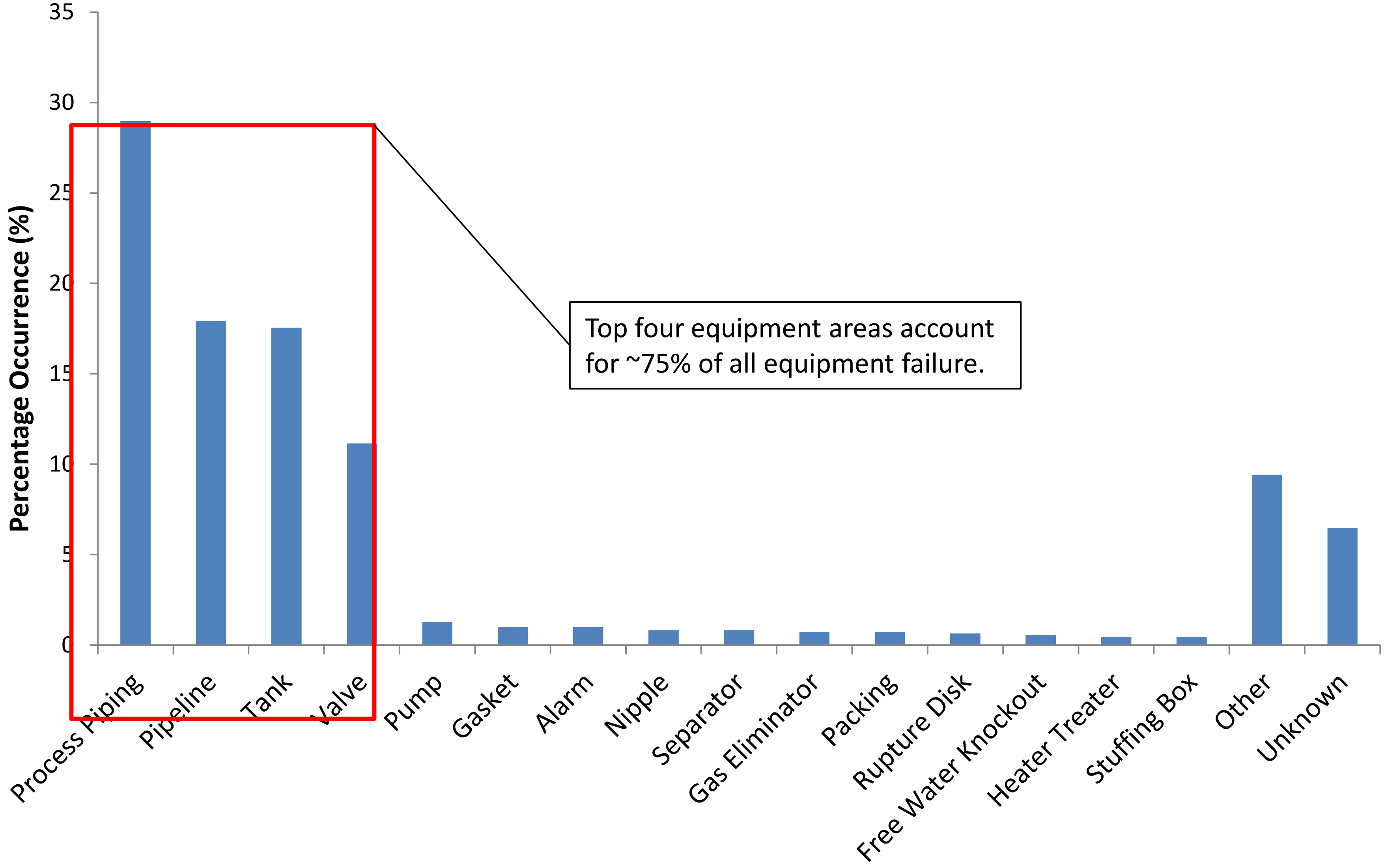


Figure 3. Equipment Involved in Releases

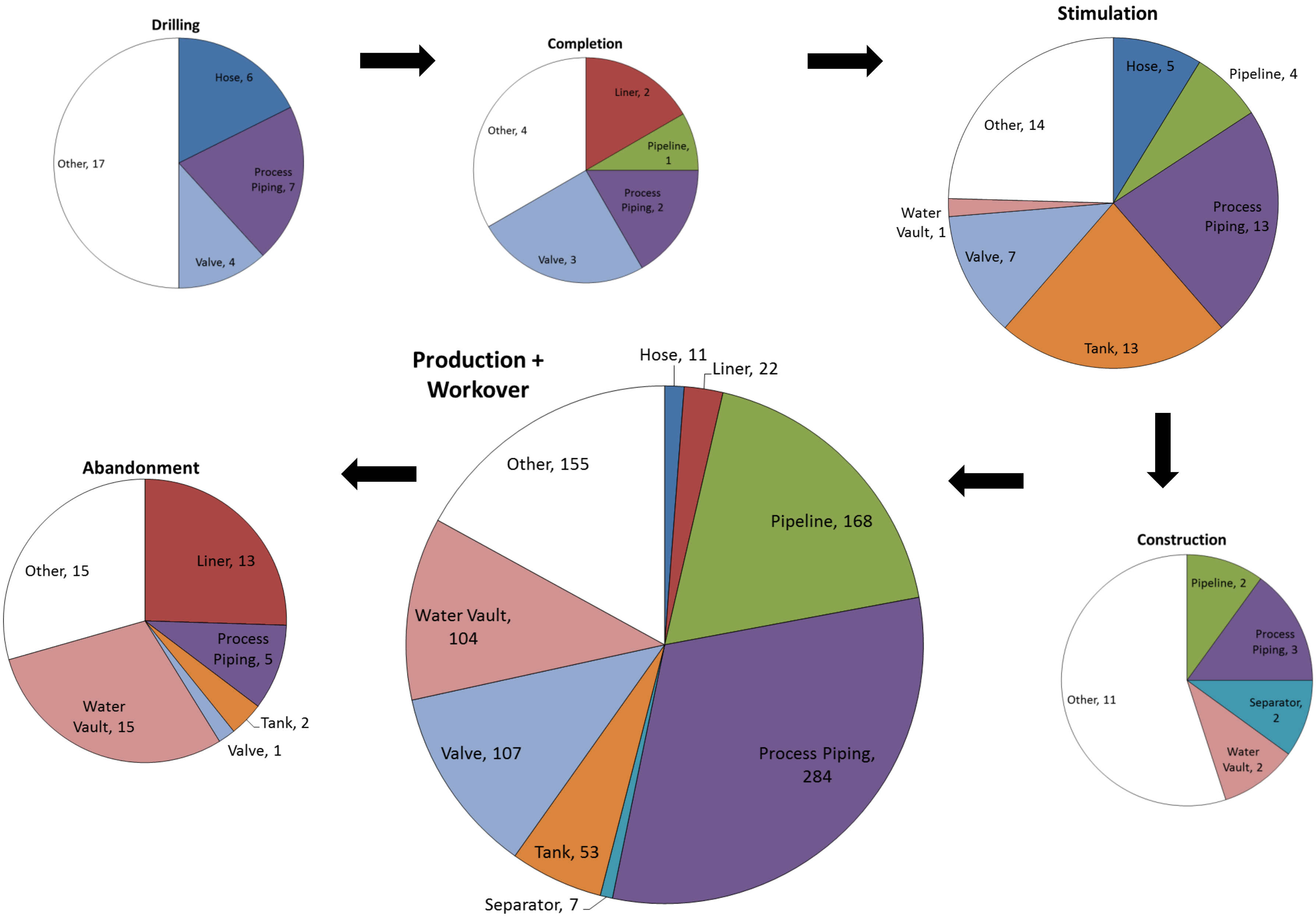
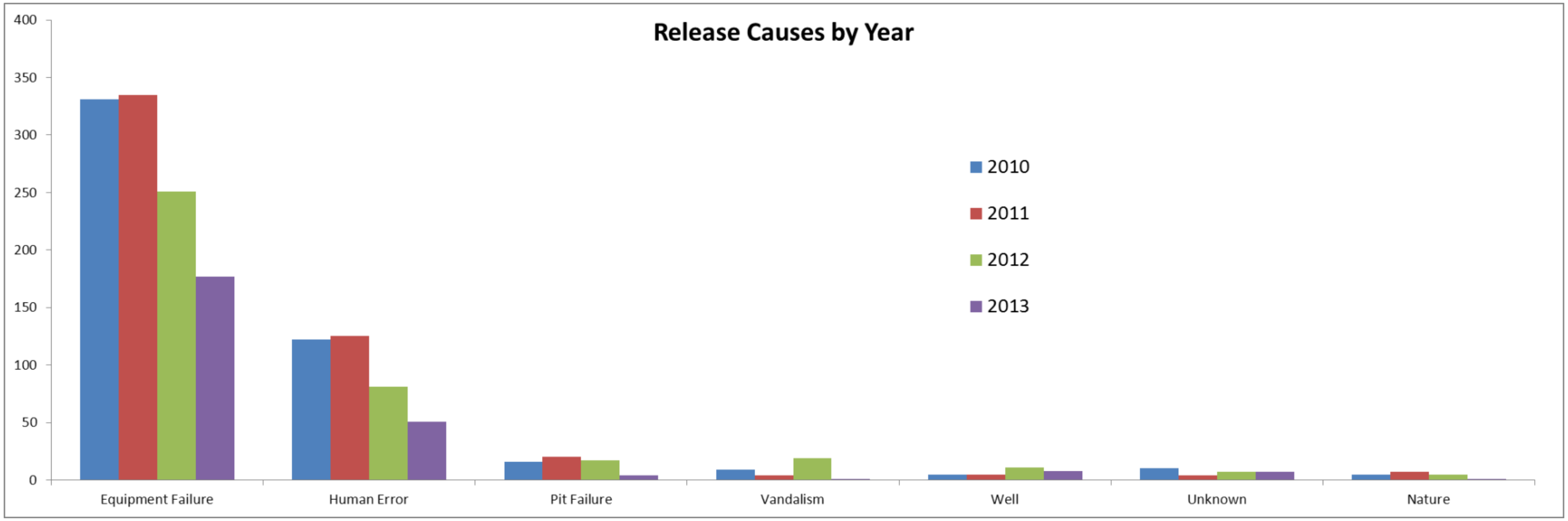


Figure 4. Equipment Failure by Operational Phase (counts)



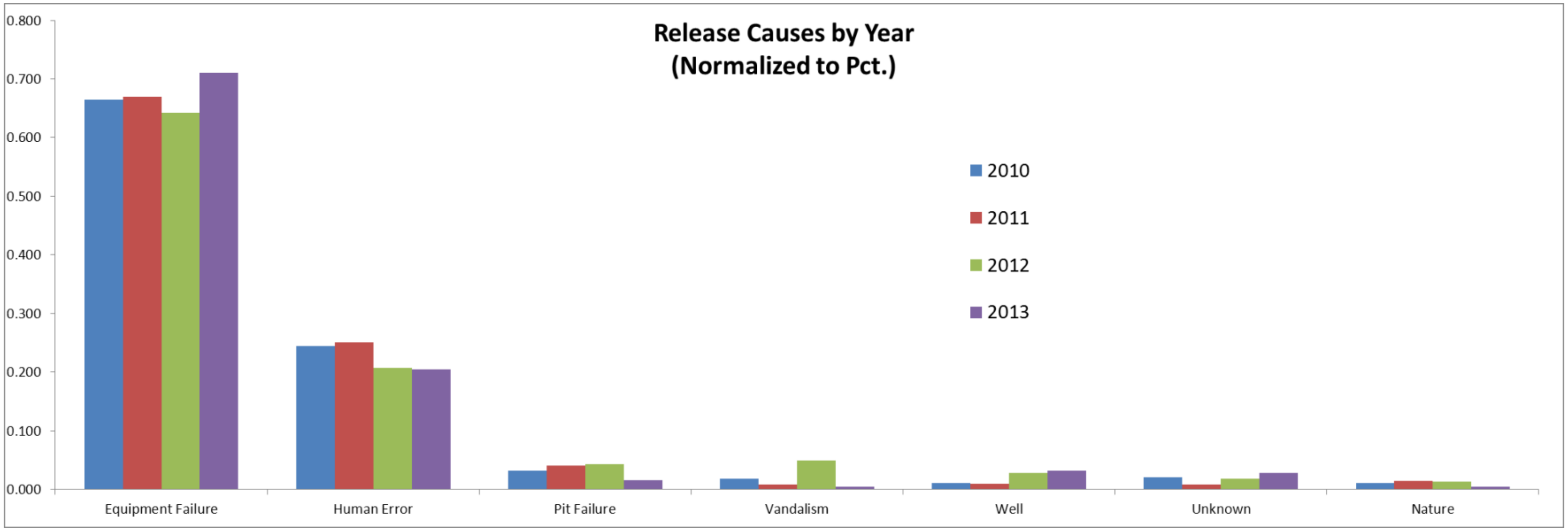


Figure 5a. Release Causes Broken Down by Year

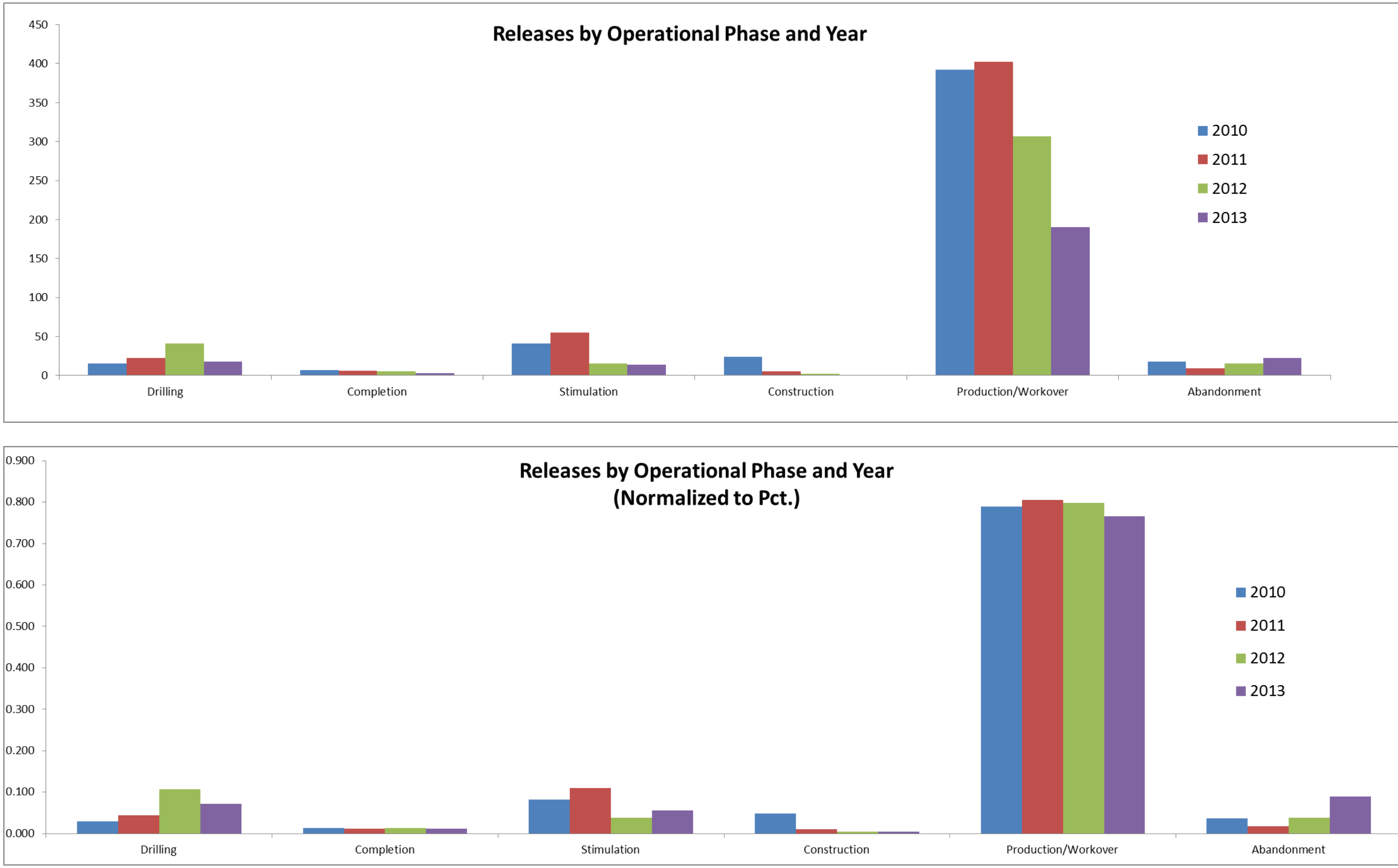
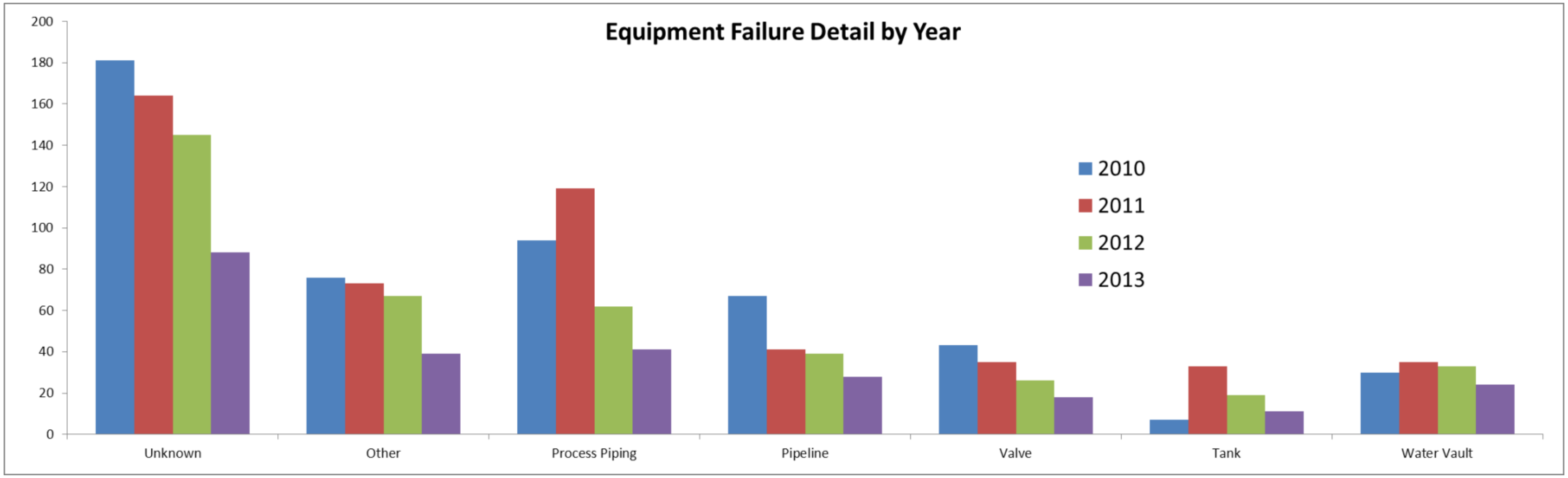


Figure 5b. Releases by Operational Phase Broken Down by Year



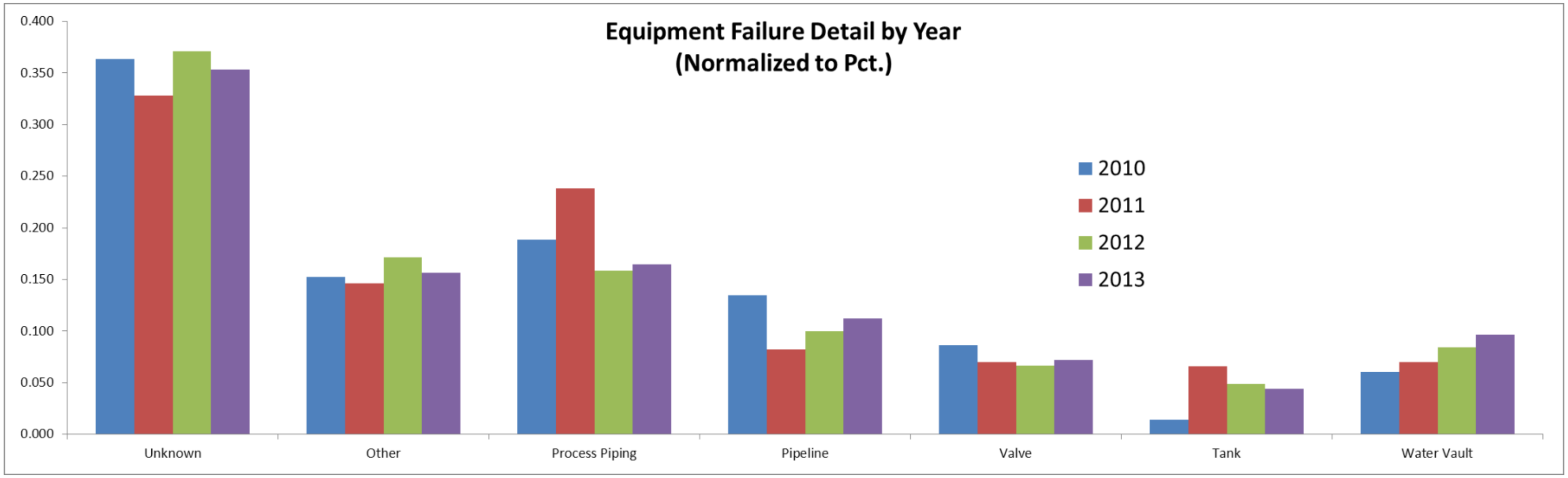


Figure 5c. Equipment Failure Detail Broken Down by Year

Tables

Table 1 – Summary of Operational Phases

Operational Phase	Count of Reported Spills	Percent of Count	Average Spill Volume (bbls)[1]
Production	1,277	78%	104[2]
Stimulation	125	8%	86
Drilling	96	6%	50
Completion	21	1%	33 (147)[3]
Workover	14	1%	44
Construction	32	2%	31
Abandoned	73	4%	24
Totals	**1,638**	**100%**	**--**

[1] For many spills, the spill volume is unknown and unreported; therefore, the average spill volume provided for each category represents the sum of the known volume (in bbls) divided by the total number of reported releases that *also* had a reported volume.

[2] Does not include one 35,000-bbl fresh water spill.

[3] Including one 1,500-bbl spill due to a torn liner and one 740-bbl spill due to a well casing failure at the well head.

Table 2 – Summary of Cause

Cause	Count of Reported Spills	Percent of Count	Average Spill Volume (bbls)[1]
Equipment Failure	1,094	67%	104[2]
Human Error	379	23%	66
Pit Failure	57	3%	483
Vandalism	33	2%	181
Well	29	2%	22
Nature	18	1%	61
Unknown Cause	28	2%	117
Totals	**1,638**	**100%**	**--**

[1] For many spills, the spill volume is unknown and unreported; therefore, the average spill volume provided for each category represents the sum of the known volume (in bbls) divided by the total number of reported releases that *also* had a reported volume.

[2] Does not include one 35,000-bbl fresh water spill.

Table 3 – Summary of Equipment Failure

Equipment	Count of Reported Spills	Percent of Count	Average Spill Volume (bbls)[1]
Process Piping	317	29%	139
Pipeline	196	18%	100
Tank + Water Vault	192	18%	52[2]
Valve	122	11%	129
Pump	14	1%	69
Alarm	12	1%	65
Gasket	11	1%	54
Nipple	9	1%	28
Separator	9	1%	8
Gas Eliminator	8	1%	27[3]
Packing	8	1%	9
Rupture Disk	7	1%	36
Free Water Knockout	6	1%	38
Heater Treater	5	0%	25
Stuffing Box	5	0%	11
Other	123	11%	55
Unknown	71	6%	236
Totals	**1,094**	**100%**	**--**

[1] For many spills, the spill volume is unknown and unreported; therefore, the average spill volume provided for each category represents the sum of the known volume (in bbls) divided by the total number of reported releases that *also* had a reported volume.

[2] Does not include one 35,000-bbl fresh water spill.

[3] Does not include one 4,500-bbl produced water spill.

Table 4 – Summary of Equipment Failure Location

Equipment Location	Count of Reported Spills	Percent of Count	Average Spill Volume (bbls)[1]
Tank	452	39%	55[2]
Well	240	21%	176
Pipeline	217	19%	128
Separator[3]	83	7%	36
Drill Pad	34	3%	37
Pump[4]	34	3%	87
Compressor[5]	12	1%	47
Gas Processing Plant	9	1%	20
Truck	8	1%	25
Pit	5	0%	205
Totals	**1,094**	**100%**	**--**

[1] For many spills, the spill volume is unknown and unreported; therefore, the average spill volume provided for each category represents the sum of the known volume (in bbls) divided by the total number of reported releases that *also* had a reported volume.

[2] Does not include one 35,000-bbl fresh water spill.

[3] Associated equipment includes process piping (28), valve (12),,separator (9), rupture disk (6), free water knockout (5), and heater-treater (5).

[4] Includes well or well pad (22), tank battery (6), water plant (4).

[5] Nine of 12 failures at compressor stations.

Table 5 – Summary of Spill Size by Volume

Spill Size	Count of Reported Spills	Percent of Count
XL - more than 100 bbls	192	12%
L - 51 to 100 bbls	128	8%
M - 11 to 50 bbls	496	30%
S - 2 to 10 bbls	318	19%
XS - 1 bbl	14	1%
Unknown	490	30%
Totals	**1,638**	**100%**

Table 6 – Summary of Cause by Operational Phase – Counts

Cause	Construction	Drilling	Completion	Stimulation	Production	Workover	Abandonment	Totals
Equipment Failure	20	34	10	57	926	6	41	**1094**
Human Error	9	49	9	64	241	4	3	**379**
Nature		1			17			**18**
Pit Failure		3	2		28	1	23	**57**
Vandalism					33			**33**
Well		8		4	12	2	3	**29**
Unknown Cause	3	1			20	1	3	**28**
Totals	**32**	**96**	**21**	**125**	**1277**	**14**	**73**	**1638**

Table 7 – Summary of Human Error Cause

Human Error	Count	Percent
Failure to Check Equipment	221	58%
Overfill	87	23%
Inadequate Training	40	11%
Damage While Digging	15	4%
Truck Crash	15	4%
None	1	0%
Totals	**379**	**100%**

Table 8 –Five Largest Petroleum Spills by Volume

Petroleum Spilled (bbls)	Operational Phase	Cause
398	Production	Vandalism
377	Production	Vandalism
340	Production	Vandalism
318	Production	Human Error
311	Production	Human Error

Table 9 – Five Largest Water Spills by Volume

Water Spilled (bbls)	Operational Phase	Cause	Equipment Location	Equipment
35,000	Production	Equipment Failure	Tank	Tank
4,500	Production	Equipment Failure	Pipeline	Gas Eliminator
4,000	Production	Equipment Failure	Well	Process Piping
3,700	Production	Equipment Failure	Well	Valve
3,000	Production	Equipment Failure	Well	Valve

Table 10 – Cause of Historical Releases

Cause	Count of Reported Spills	Percent of Count
Equipment Failure	**235**	**82%**
Water Vault	85	36%
Process Piping	73	31%
Unknown	59	25%
Tank	5	2%
Gathering Line	4	2%
Valve	3	1%
Pipeline	3	1%
Separator	2	1%
Seal	1	0%
Pit Failure	**29**	**10%**
Unknown Cause	**19**	**7%**
Human Error	**5**	**2%**
Totals	**288**	**100%**

Table 11 – Location of Historical Releases

Location	Count of Reported Spills	Percent of Count
Tank	194	67%
Pit	29	10%
Unknown	24	8%
Well	21	7%
Separator	9	3%
Pipeline	6	2%
Gas Processing Plant	3	1%
Compressor	2	1%
Totals	**288**	**100%**

Appendices

Appendix 1 – Spill/Release Report, Form 19

FORM 19 Rev 6/99

Click here to reset form

State of Colorado
Oil and Gas Conservation Commission
1120 Lincoln Street, Suite 801, Denver, Colorado 80203 (303)894-2100 Fax:(303)894-2109

FOR OGCC USE ONLY

Spill report taken by:

FACILITY ID:

SPILL/RELEASE REPORT

This form is to be submitted by the party responsible for the oil and gas spill or release. Any spill or release which may impact waters of the State must be reported as soon as practicable; any spill over 20 bbls must be reported within 24 hours and all spills over five bbls must be reported within ten days. Submit a Site Investigation and Remediation Workplan (Form 27) when requested by the Director.

OPERATOR INFORMATION

Name of Operator: ____________ OGCC Operator No: ____________

Address: ____________

City: ____________ State: _____ Zip: ____________

Contact Person: ____________

Phone Numbers

No: ___ ____________

Fax: ____________

E-Mail: ____________

DESCRIPTION OF SPILL OR RELEASE

Date of Incident ________ Facility Name & No.: ____________

Type of Facility (well, tank battery, flow line, pit): ____________

Well Name and Number: ____________

API Number: ____________

County: ____________

QtrQtr: ________ Section: ________

Township: ________ Range: ________

Meridian: ________

Specify volume spilled and recovered (in bbls) for the following materials:

Oil spilled: ______ Oil recov'd: ______ Water spilled: ______ Water recov'd: ______ Other spilled: ______ Other recov'd: ______

Ground Water impacted? ☐ Yes ☐ No Surface Water impacted? ☐ Yes ☐ No

Contained within berm? ☐ Yes ☐ No Area and vertical extent of spill: ________ x ________

Current land use: ____________ Weather conditions: ____________

Soil/geology description: ____________

IF LESS THAN A MILE, report distance IN FEET to nearest.... Surface water: ______ wetlands: ______ buildings: ______

Livestock: ______ water wells: ______ Depth to shallowest ground water: ______

Cause of spill (e.g., equipment failure, human error, etc.): ____________ Detailed description of the spill/release incident:

CORRECTIVE ACTION

Describe immediate response (how stopped, contained and recovered):

Describe any emergency pits constructed:

How was the extent of contamination determined:

Further remediation activities proposed (attach separate sheet if needed):

Describe measures taken to prevent problem from reoccurring:

OTHER NOTIFICATIONS

List the parties and agencies notified (County, BLM, EPA, DOT, Local Emergency Planning Coordinator or other).

Date	Agency	Contact	Phone	Response

Spill/Release Tracking No: ____________

Appendix 2 – Database fields supplied by COGCC and the associated Form 19 field

Field Name (COGCC database)	How it looks on the Form 19
company_name	Name of Operator:
operator_num	OGCC Operator No:
incident_date	Date of Incident:
county	County:
facility_type	Type of Facility (well, tank battery, flowline, pit):
	The following six fields have this header - Specify volume spilled and recovered (in bbls) for the following materials:
oil_Spill	Oil spilled:
Oil_Recover	Oil recov'd:
water_spill	Water spilled:
water_recov	Water recov'd
other_spill	Other spilled:
other_recov	Other recov'd
water_impact	Ground Water impacted? Y N
Surf_Impact	Surface Water impacted? Y N
contained	Contained within berm? Y N
	The following four database fields come from one field on Form 19 -
area	Area and vertical extent of spill:
area_unit	Area and vertical extent of spill:
vertical	Area and vertical extent of spill:
vert_unit	Area and vertical extent of spill:
land_use	Current land use:
	The following six fields have this header - IF LESS THAN A MILE, report distance IN FEET to nearest…
wetlands	wetlands:
surf_water	Surface water:
shallow_depth	Depth to shallowest ground water:
buildings	buildings:
livestock	Livestock:
water_wells	Water wells:
spill_desc	Detailed description of the spill/release incident:
extent	How was the extent of contamination determined?
preventative	Describe measures taken to prevent problem from reoccurring:
desc	Cause of spill (e.g. equipment failure, human error, etc.):
doc_num	Spill/Release Tracking No:
trkg_num	Spill/Release Tracking No:

Appendix 3 – Database fields created by SSPA to aid in analysis

Created Field for Research	Description
Operational Phase	Categorized spill reports into operational phases
Operational Sub-Phase	Sub-Categorized spill report operational phases (historical, etc)
Cause	Categorized spill reports into causes
Sub-Cause	Sub-Categorized spill report causes
Equipment Location	Categorized equipment failures into locations
Equipment	Categorized equipment failures by equipment name
Equipment Details	Sub-Categorized equipment failures by equipment name
Spill Size - Oil	Categorized oil spill sizes (S, M, L, etc.)
Spill Size - Water	Categorized water spill sizes (S, M, L, etc.)
Spill Size - Other	Categorized other spill sizes (S, M, L, etc.)
Spill Type	Categorized spill reports into material spilled (oil, water, mixture)
Size (bbls)	Summed oil, water, and other spill size
Total Size	Categorized summed spill sizes (S, M, L, etc.)

Appendix 4 – Complete List of Equipment Failure Detail

Row Labels	Count of Equipment Details
Actuator	1
Alarm	1
Automatic Shut-in Valve	1
Baffles	1
Ball Valve	7
Beam Pump	1
Bearing	1
Blender Discharge	1
Block Valve	1
Blown Crush Cap	1
Blowout Preventer	2
Bradenhead Valve	2
Bull Plug	1
Bull Valve	1
Burner Tube	1
Butterfly Valve	3
Bypass Line	5
Cam Lock Fitting	3
Cap	1
Catch Tank	1
Centrifuge	1
Check Valve	8
Coalbed Methane Pipeline	1
Collar	3
Concrete	51
Condensate Tank	1
Connection	7
Consolidation Line	1
Coupling	1
Dewatering Pump	1
Discharge Line	11
Drain Line	2
Drain Valve	5
Dresser Sleeve	3
Drive Head	1
Dump Line	115
Dump Valve	1

Row Labels	Count of Equipment Details
Elbow	1
Electromagnetic Meter Valve	1
Equalization Valve	1
Equalizing Line	1
Fiberglass Collar	1
Fire Tube	4
Fitting	5
Flange	1
Float Chamber	1
Flowback Line	3
Flowback Tank	6
Flowline	83
Flowline Relief Valve	1
Flowline Valve	1
Frac Line	2
Frac Tank	8
Frost Free Valve	1
Fuse	4
Fusion Coupler	1
Gas Eliminator	1
Gas Supply Line	1
Gasket	5
Gate Valve	2
Gathering Line	20
Gunbarrel Tank	3
Hammer Union	1
Hammer Union Gasket	1
Hatch	3
Hatch Seal	1
HDPE Line	1
Header Line	2
Header Manifold	1
Hi Low Valve	1
High Fluid Alarm	1
High Level Shut Down	1
High Point Vent	1
High Pressure Plumbing	1
High Tank Level Alarm	2

Row Labels	Count of Equipment Details
High Water Alarm	3
Hose	1
Hydraulic Line	2
Injection Line	14
Injection Pump	1
Injection Pump Plunger	2
Inspection Plate Gasket	2
Insulating Gasket	1
Isolation Valve	4
Kill Switch	1
Level Sensor	1
Liner	2
Load Line	5
Load Line Valve	3
Low Pressure Safety Valve	1
Low Suction Manifold	1
Low Torc Valve	1
Lubricator Cap	1
Manifold	3
Motor Valve	1
Mud Flowline	5
Mud Pump	2
Mud Tank	1
Needle Valve	1
None	398
Oil Dump Line	15
Oil Dump Valve	1
Oil Line	1
Overflow Piping	1
Overflow Valve	1
Packing	5
Pipe connector	1
Plug	1
Plunger end cap	1
Plunger Packing	1
Poly Pipe	12
Poly Pipe Valve	1
Popoff	1

Row Labels	Count of Equipment Details
Pressure Safety Valve	1
Pressure Valve	1
Primer Valve	1
Produced Water Line	27
Produced Water Pump	3
Produced Water Tank	3
Production Line	1
Production Lines	2
Production Tank	31
Radigan Valve	1
Recycle Pump	1
Return Line	1
Riser	3
Rubbers	4
Seal	3
Seat	1
Shaker Screen	1
Shut-In Valve	1
Sight Glass	2
Sledge	1
Slope Tee Blow Down	1
Slug Catch	1
Spool Piece	1
Storage Tank	3
Stuffing Box	1
Suction Hose	1
Suction Pressure Transmitter	1
Surface Casing Valve	1
SWD Line	1
Swedge	2
Tank Valve	11
Tee	1
Top Dump Valve	1
Transfer Pump	4
Treater Fire Tube Gasket	1
Tubing	1
Union	2
Unloading Valve	1

Row Labels	Count of Equipment Details
Upper Manifold Valve	1
Vac Truck	1
Vessel	1
Water Drain Valve	1
Water Dump Line	7
Water Injection Line	1
Water Lateral Line	1
Water Line	24
Water Manifold	1
Water Pump	1
Water Sensing Line	1
Water Supply Tank	1
Water Tank	1
Water Transfer Line	4
Water Vault	1
Grand Total	**1094**

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APPENDIX C: COMMISSION RULES AND POLICIES FOR WELLBORE INTEGRITY AND HYDRAULIC FRACTURING

Figure C-1: Commission Engineering Rules Governing Well Integrity

Rule	Title
207	TESTS AND SURVEYS
301	RECORDS, REPORTS, NOTICES-GENERAL
303	REQUIREMENTS FOR FORM 2, APPLICATION FOR PERMIT-TO-DRILL, DEEPEN, RE-ENTER, OR RECOMPLETE, AND OPERATE; FORM 2A, OIL AND GAS LOCATION ASSESSMENT
308A	COGCC Form 5. DRILLING COMPLETION REPORT
308B	COGCC Form 5A. COMPLETED INTERVAL REPORT
309	COGCC Form 7. OPERATOR'S MONTHLY PRODUCTION REPORT
311	COGCC Form 6. WELL ABANDONMENT REPORT
314	COGCC Form 17. BRADENHEAD TEST REPORT
316A	COGCC Form 14. MONTHLY REPORT OF NON-PRODUCTED WATER FLUIDS INJECTED
316B	COGCC Form 21. MECHANICAL INTEGRITY TEST
316C	NOTICE OF INTENT TO CONDUCT HYDRAULIC FRACTURING TREATMENT
317	GENERAL DRILLING RULES
	a. Blowout prevention equipment (“BOPE”)
	c. Requirement to post permit at the rig and provide spud notice
	d. Casing program to protect hydrocarbon horizons and ground water
	e. Surface casing where subsurface conditions are unknown.
	f. Surface casing where subsurface conditions are known
	g. Alternate aquifer protection by stage cementing
	h. Surface and intermediate casing cementing
	i. Production casing cementing
	j. Production casing pressure testing
	k. Protection of aquifers and production stratum and suspension of drilling operations before running production casing
	m. Protection of productive strata during deepening operations
	n. Requirement to evaluate disposal zones for hydrocarbon potential
	o. Requirement to log well
	p. Remedial cementing during recompletion
317A	SPECIAL DRILLING SPECIAL DRILLING RULES - D–J BASIN FOX HILLS PROTECTION AREA
	a. Surface Casing - Minimum Requirements for Well Control
	b. Surface Casing - Aquifer Protection
	c. Exploratory Wells
319	ABANDONMENT
321	DIRECTIONAL DRILING
325	UNDERGROUND DISPOSAL OF WATER

Figure C-1, cont.: Commission Engineering Rules Governing Well Integrity

Rule	Title
326	MECHANICAL INTEGRITY TESTING
327	LOSS OF WELL CONTROL
341	BRADENHEAD MONITORING DURING WELL STIMULATION OPERATIONS
404	CASING AND CEMENTING OF INJECTION WELLS
603	DRILLING AND WELL SERVICING OPERATIONS AND HIGH DENSITY AREA RULES
608E	COALBED METHANE WELLS BRADENHEAD TESTING

Figure C-2: Commission Engineering Policies Governing Well Integrity

Table Entry #	Title	Date Issued or Revised
1	Bradenhead Monitoring During Hydraulic Fracturing Treatments in the Greater Wattenberg Area	29-May-12
2	Practices and Procedures, UIC Mechanical Integrity Tests	17-Mar-11
3	Notice to Operators Drilling Williams Fork Formation Wells in Garfield County, Surface Casing Depth and Modification of Leakoff Test Requirements	23-Jun-06
4	Notice to Operators Drilling Mesaverde Group or Deeper Wells in the Mamm Creek Field Area in Garfield County, Well Cementing Procedure and Reporting	9-Feb-07
5	Notice to Operators Drilling Wells in the Buzzard, Mamm Creek, and Rulison Fields, Garfield County and Mesa County, Procedures and Submittal Requirements for Compliance with COGCC Order Nos. 1-107, 139-56, 191-22, and 369-2	10-Jul-10
6	Notice to All Oil and Gas Operators Active in the Denver Basin, Colorado Oil and Gas Conservation Commission Approved Wattenberg Bradenhead Testing and Staff Policy	16-Dec-09
7	Drilling Completion Report - Cement Documentation Policy	17-Feb-09
8	Clarification on Procedures for Filing Changes to Applications for Permit-to-Drill, revised January 18, 2011	18-Jan-11
9	Conductor Pipe Setting Policy	6-Apr-06
10	Approval of Casing Repairs Policy	
11	Northwest Colorado Notification Policy, Effective for Notices Received On or After January 1, 2010	10-May-12

Figure C-3: Commission Hydraulic Fracturing Rules

Rule	Application
205	Inventory chemicals
205A	Chemical disclosure
317	Well casing and cementing; Cement bond logs
317B	Setbacks and precautions near surface waters and tributaries that are sources of public drinking water
341	Monitoring pressures during stimulation
608	Special requirements for coal-bed methane wells
903 & 904	Pit permitting, lining, monitoring, & secondary containment
906	Requires COGCC notify CDPHE and the landowner of any spill that threatens to impact any water of the state

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