

EVALUATION OF VOC EMISSION CONTROLS FOR OIL AND GAS PRODUCTION STORAGE TANKS

Ray McKaskle, Kevin Fisher, and Katherine Searcy
Trimeric Corporation
Buda, Texas, U.S.A.

Curtis Rueter
Noble Energy, Inc.
Denver, Colorado, U.S.A.

ABSTRACT

Recent regulations in Colorado as well as other oil and gas producing states have begun to require control of flashing emissions from oil and gas production site storage tanks. In this paper, Trimeric Corporation and Noble Energy, Inc. will present the results of a six-month on-site evaluation of VOC emissions controls and control strategies for oil and gas production site storage tanks. Advantages and disadvantages of multiple types of three-phase separators, enclosed flares, and vapor recovery units will be presented. Benefits of a new type of separator designed to reduce VOC emissions and separator fuel usage will be reviewed. Advantages and disadvantages of using slug catchers upstream of separators and surge bottles downstream of separators to reduce peak and average VOC volumes requiring treatment will also be presented. Benefits of changes in operational practices, including keeping a small amount of back-pressure on storage tanks and reducing the volume of separator dumps, will also be discussed.

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INTRODUCTION

This paper summarizes the results of an extensive evaluation in 2007 of volatile organic compound (“VOC”) emission control strategies at oil and gas production facilities in Northern Colorado operated by Noble Energy, Inc. (“Noble”). This effort was driven by Noble’s efforts to comply with regulatory requirements from the Colorado Department of Public Health and Environment in a cost-effective manner using equipment proven to be reliable, economic, and safe. To complete this work, Noble and Trimeric engineers worked closely with production personnel, emission control equipment vendors, environmental staff, and others to carefully collect and analyze data on the operations of several types of separators, flare systems, vapor recovery units, and associated strategies for reducing peak emission rates. The results of this work demonstrate that there are significant opportunities to improve and optimize VOC emission controls, while in some cases even increasing revenue. This paper is intended to share some of the valuable lessons that were learned along the way and should serve as a useful resource for others with similar needs.

BACKGROUND

Regulations

The Denver area has faced increasing air quality challenges over the past several years in meeting the 8-hour ozone standard. As part of an Early Action Compact (EAC) agreement with EPA, the Colorado Department of Public Health and Environment (CDPHE) required control of flash emissions from oil and gas storage tanks beginning in 2005.

In developing a control strategy, CDPHE worked with the industry to develop an innovative regulatory approach that required companies to achieve a certain percentage reduction in their emissions across the entire ozone maintenance area, rather than a traditional threshold-based approach to regulations (i.e., controlling all sources over a certain size). As a result, the regulations created an incentive for companies to exceed the percentage reduction required so that upset conditions (e.g., control equipment failures) would not cause a company’s overall percentage reduction to fall below the desired percentage target.

CDPHE’s Regulation 7 initially required a 37.5 % reduction in emissions from storage tanks in 2005 and a 47.5 % reduction in 2006 and beyond. Due to faster-than-expected growth in production and therefore flash emissions, the level of control was increased to 75% for 2007.

Regulation 7 requires that control devices at each site achieve at least a 95% reduction in emissions. Although performance tests have shown that the burners typically used at many of the sites may achieve destruction efficiencies exceeding 99.5%, the industry was concerned during the initial rulemaking in 2003-04 about the capture efficiency for the emissions because of the potential for pressure relief valve venting at unmanned facilities as well as the challenges in maintaining a tight seal around the hatch on the tank. Because test measurements indicated that these possible leaks were relatively small in those instances where they did occur, the combined capture and destruction efficiency was set at 95% in the regulations.

Description of Typical Operations

Noble's operations in the Wattenberg field northeast of Denver are typical of exploration and production facilities in the area. Noble's operations produce sweet natural gas and condensate, with the condensate's API gravity typically ranging from the mid-40s to the low 50s. For the purposes of this paper, the term "oil" refers to this condensate. The wells typically have low average flow rates; the average production rates from all producers in Weld County in November 2006 were 36 Mscfd of gas and 2.6 bbl/day of oil. The equipment at the production facilities includes only separators, tanks, and emission controls.

Wells at many of Noble's sites flow intermittently with the aid of a wellbore plunger. The plunger is shut-in downhole in between cycles using control valves. Reservoir fluids enter the tubing above the plunger while the plunger is still. At the beginning of the next cycle, the valves are toggled to let the plunger move freely. Reservoir pressure causes the plunger to rise rapidly. When the plunger is moving, it forms a seal with the inside surface of the tubing wall. Thus, all of the fluid above the plunger arrives at the surface production equipment in a very short period of time (5 to 30 minutes). Because the fluid arrives to the separation equipment in slugs, the design and operation of any emission control system must consider not only the average flow but also the peak flow.

The separators used at the sites are typically in one of two possible configurations. These are referred to as the "Dual Coil" or the "HLP." Figures 1 and 2 present simplified flow diagrams for the Dual Coil and HLP separators, respectively. The Dual Coil separator shown in Figure 1 is the simpler of the two designs, consisting of a single-stage, heated three-phase separator. Production from the well(s) is first routed through a coil inside the separator, which is heated by a fired heater. The coil is submerged in production fluid retained in the separator, and the high-pressure well stream fluid inside the coil is heated prior to letting the pressure down through a valve and feeding the stream into the three-phase separator. The term "Dual Coil" is used because the separator actually has two separate inlet coils and pressure let-down valves to allow simultaneous processing of production from two wells that might operate at different pressures. Oil and produced water are separated by gravity and then discharged through control valves on level control to separate storage tanks. Gas from the separator is routed to the sales pipeline, with a portion of it used as fuel for the firetube heater inside the separator. The separator is heated to facilitate the oil/water separation step.

Figure 2 shows an HLP separator. The HLP separator has two stages of separation. The first stage is a two-phase separator for separating the sales gas from the oil/water mixture. The first stage of separation in the HLP typically operates at lower temperatures than the Dual Coil. The oil and water mixture is then reduced in pressure and fed to the low pressure three-phase separator. Flash gas produced in the low pressure separator is sent to the storage tank for disposal and then usually is routed to an emission control device. Oil and water from the low pressure separator are heated again in the low pressure separator with a firetube to facilitate the oil/water separation step.

In either separator, the VOC emissions originate primarily from the flashing step, as the pressure is reduced between the separator pressure and atmospheric pressure storage tank. Flashing losses are emissions that result as liquids are flashed to pressures below their bubble point pressure. The amount of flash emissions at a given location depends on many factors, including the type of unit operations (e.g., number of stages of separation), the temperatures and pressures of the unit operations, and variations in flow rate and operating conditions. The Colorado Oil and Gas Association (COGA), in conjunction with CDPHE, developed an average emission factor of 13.7 lb VOC/bbl oil that is commonly used; however, site-specific emission factors may range from roughly 50% up to 200+% of this average factor.

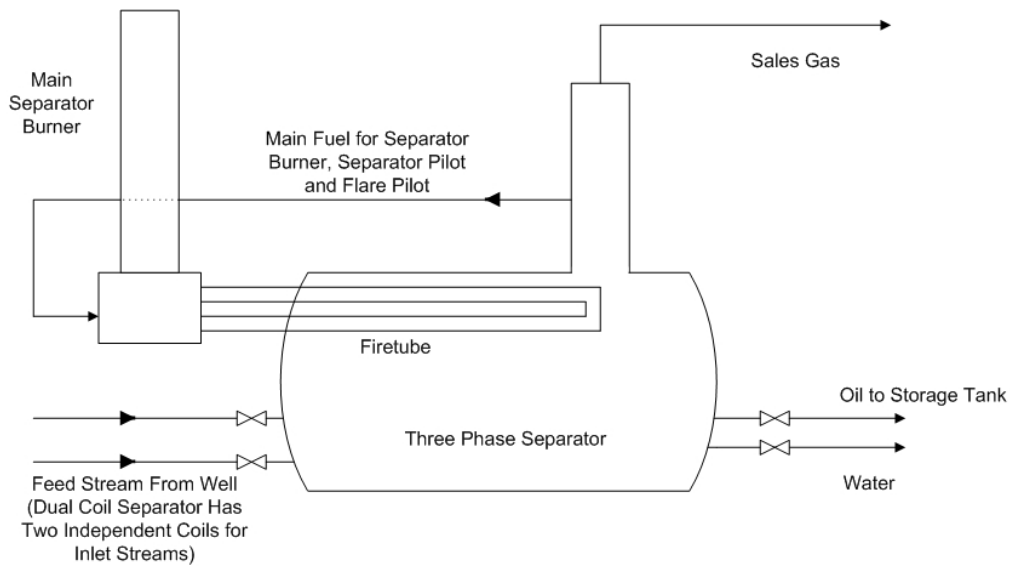


Figure 1 - Dual Coil Schematic

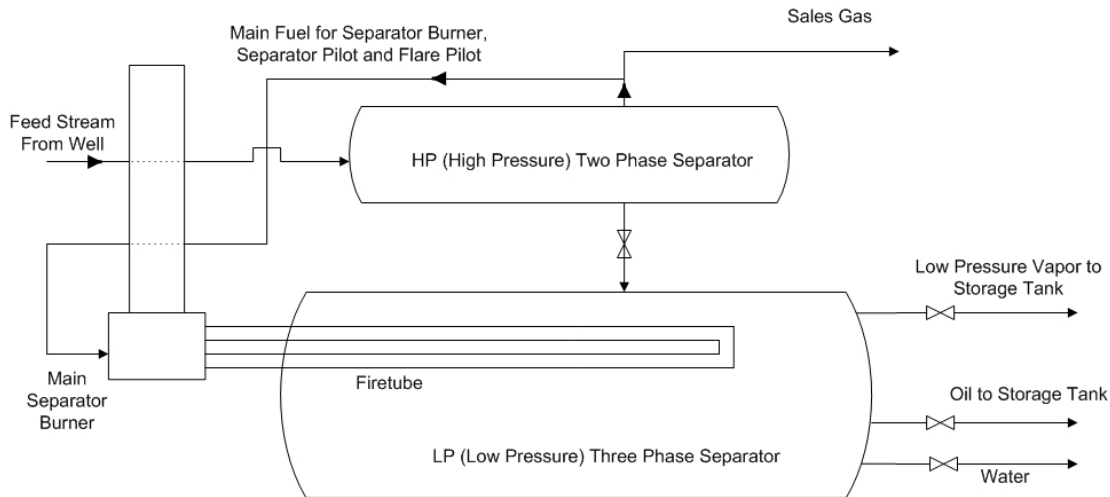


Figure 2 - HLP Schematic

In addition to the flashing losses, working losses can occur as vapors are displaced from the storage tank headspace when the tank is filled. Breathing losses, also known as “standing” losses, can occur as the temperature and pressure in the storage tank fluctuate and volatilize lighter components. Often, these fluctuations in the storage tank result from diurnal temperature swings.

Study Objectives

The primary focus of this study was to identify reliable, field-proven, cost-effective methods for complying with the Regulation 7 VOC emission control requirements for storage tanks. Project objectives were met by measuring, understanding, and evaluating flashing losses for different separator and emission control configurations in operation at these facilities.

Technologies Evaluated

The options evaluated in this study may be classified as follows:

- Separator modifications;
- Peak flow management approaches;
- Improved burner technologies; and
- Vapor recovery units.

Separator modifications may include mechanical design changes as well as process optimization to reduce emissions. For process optimization, the temperatures and pressures in the HP and LP vessels of the HLP separator may be varied within operational constraints to reduce emissions and increase revenue. The feed to the separations equipment may limit the range of operating combinations in each separator; for example, feeds with high paraffin content require higher temperatures in the LP separator in order to “break” the paraffins; these high temperatures can reduce oil production and increase flashing losses when compared to a feed with lower paraffin content, which allows a lower temperature in the LP separator.

“Mechanical design changes” to the separator involved additional equipment, such as the VGR separator that was tested. Figure 3 shows a VGR separator, which has two stages of separation. The VGR has a packed tower on top of the high-pressure separator. This tower is one of the main design differences of the VGR relative to the HLP and Dual Coil separators. The purpose of the packed tower is to sharpen the hydrocarbon separation in the produced oil and gas by sending more of the light hydrocarbons out with the sales gas and keeping more of the heavy hydrocarbons in the sales oil. In general, the heavier hydrocarbons are worth more when sold as oil than as natural gas. Similarly, more value is recovered from the methane and light ends when these components go into the sales gas and the flashing losses due to these components are reduced at the storage tank. Another key difference in the VGR relative to the HLP and the Dual Coil separators is that some of the gas from the low-pressure separator (called the “Flash Absorber” in the VGR) is used as fuel for the separator pilot, separator burner, and flare pilot. By contrast, the HLP low-pressure separator gas is sent to the storage tank and then to the control device; the Dual Coil separator does not have a low-pressure separator.

Peak flow management approaches are strategies that are intended to mitigate the negative impacts of flow variations on flashing losses. For example, slug catchers may be installed between the well and separation equipment. Additionally, surge bottles with appropriate controls may be installed between the separation equipment and the atmospheric storage tanks. The slug catchers and surge bottles provide a buffer for the separation or control equipment and reduce capital requirements because the separation and control equipment may be sized for less than the peak flow rate. Appropriate design and controls for the surge bottle and slug catcher strategies are discussed in the Field Evaluation Program section of this paper.

Once emissions are generated, two types of control approaches are generally used: combustion and vapor recovery units (“VRUs”). Combustion may include open or enclosed flares (also referred to in the field as “burners”). Enclosed flares have several advantages over open flares. Enclosed flares typically have a higher destruction efficiency than open flares, the flame is not visible, and combustion control is generally easier. Figure 4 shows a picture of a typical enclosed flare; the 48” diameter enclosed flare is the largest stack shown. Some key features of this flare are as follows:

- Inlet gas enters from the back right and goes up through a flame arrestor and then to a matrix of burner manifolds.
- Proprietary air aspiration and mixing equipment is not shown, but is installed inside the unit. Air mixing is crucial to obtain efficient combustion with a relatively rich gas (1.4 typical specific gravity), minimal inlet pressure (< 1 psig), and no electricity to power a blower for air / fuel mixing.

- Separate burner manifolds use valves that open and close based on pressure of the feed gas to the flare. This acts as a staging mechanism in the flare that uses a number of burner manifolds that is proportional to the inlet gas pressure (feed rate). Staging the manifolds helps prevent vibration issues as the inlet gas rate quickly rises up and down during the production cycle and smoking at the end of the production cycle when the feed gas rate to the burner is tapering off.

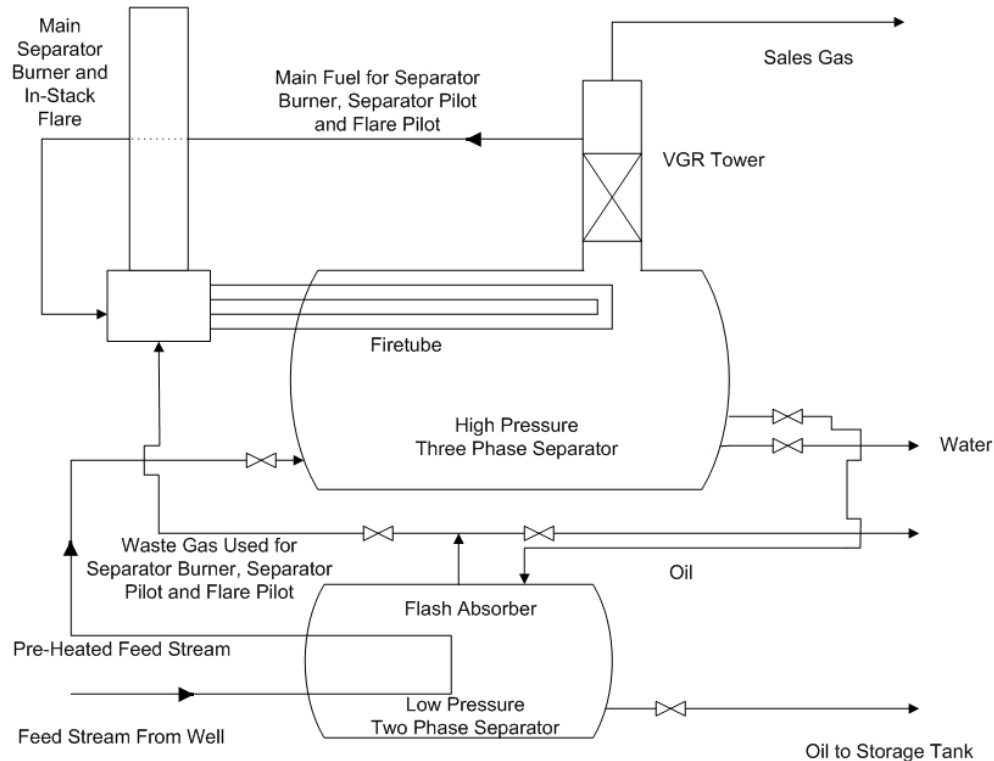


Figure 3 - VGR Schematic

Combustion emission control options typically have lower capital and operating costs than VRUs, are more reliable, require less maintenance, and do not risk oxygen contamination of sales gas. Drawbacks to using flares in this application are loss of additional sales gas revenue, which can be obtained using a VRU, and generation of combustion byproducts, including NO_x , CO , and CO_2 . Safe work practices and concerns regarding high-temperature equipment must also be evaluated when using enclosed flares in this application. While maintenance is lower with flares compared to other control strategies, there are regular service requirements, including clearing condensate from the inlet gas line, verifying pilot operation, ensuring that bird screens are clean and in place, and verifying that the flame arrestor on the feed gas line and on the air inlet port(s) are clear.



Figure 4 – 48” Burner (Largest Stack Shown in Picture)

VRUs are available in many configurations that utilize single-stage or multi-stage compressors, eductors, and other configurations for operation with associated separation equipment. Figures 5 and 6 show two examples of VRUs that were evaluated in this project. Descriptions of these two types of VRU systems are included in the Field Evaluation Program section. VRUs can generate revenue by capturing and compressing gas that would otherwise be vented or burned and then adding this high Btu value gas into the sales gas stream. However, compared to flares, VRUs typically have higher capital and operating costs, are more complex, require more maintenance, can be less reliable, and may cause oxygen contamination of sales gas streams if storage tanks are not properly controlled and blanketed.



Figure 5 – Example VRU #1



Figure 6 – Example VRU #2

FIELD EVALUATION PROGRAM

The general objective of the field evaluation program was to develop practical and cost-effective methods to control VOC emissions from oil and gas production facilities. This study was driven by Noble's efforts to comply with regulatory requirements from the Colorado Department of Public Health and Environment. Specific objectives were to evaluate several types of separators and control systems in the field so that benefits and costs could be quantified for several emission control alternatives. By identifying multiple cost-effective ways to meet the regulatory requirements, solutions can be tailored to site-specific factors. The field evaluation program had several parallel efforts, which are listed below and then discussed separately.

- Comparison of VGR, Dual Coil, and HLP Separators;
- Evaluation of Burner Designs;
- Testing of Surge Bottles and Slug Catchers; and
- Vapor Recovery Unit Testing.

Comparison of VGR, Dual Coil, and HLP Separators

Noble began a field evaluation of the three separator configurations (VGR, Dual Coil, and HLP) in December of 2006 to determine the performance differences among the separators in terms of emission controls, fuel consumption, and economics. Noble is using the results of the evaluation to select separators for installation at new production sites. Side-by-side tests of Dual Coil and VGR separators, both with and without plungers, began in February 2007.

Process data from the field were collected daily and recorded manually using field data sheets. Table I summarizes the process data collection methods and frequency:

Table I – Data Acquisition Matrix for Field Evaluation of Separators

Process Data	Measurement Method	Frequency
Oil production rate	Manual gauging of oil tanks	1 – 2 times daily
Sales gas rate	Sales gas flow meter	Continuously measured and logged
Fuel gas consumption	Dry gas meter	Logged daily
Waste gas to burner	Dry gas meter	Logged daily
Gas sent to flare	Dry gas meter	Logged daily
Various process temperatures and pressures	From local temperature and pressure indicators on the separator.	Logged daily

Hydrocarbon stream samples were also collected for analysis. Periodic grab samples of separator liquids, sales gas, sales oil, and flared gas were collected and analyzed for hydrocarbon composition during each test run, which was nominally about one week in duration. The heating value of the gas samples was also measured.

The biggest challenge encountered in the field testing was establishing controlled conditions for each separator so that the performance could be compared between separators. It was not possible to test each separator simultaneously using the exact same feed stream. Instead, the separators were tested in sequence, and changes in the wells' production rates had to be considered when interpreting the oil and sales gas production data from each separator. For example, the production of a given well tends to decline over time, so oil and gas production rates from each separator had to be normalized to a common well production rate in order to be comparable.

Variability in production rates was also a challenge because it created limitations in the accuracy of the measurements. For example, oil production rates determined by tank gauging on a daily basis are subject to significant variations and generally are not accurate enough to directly distinguish the marginal differences in production rates between separators. Finally, the extreme cold weather in early 2007 created problems; condensation in vapor lines interfered with dry gas meters, and freezing liquids plugged production and sales gas lines.

Field data showed that the VGR separator reduced the amount of gas sent to the flare substantially, as shown by gas meter measurements and the resulting percentages of the feed hydrocarbons that end up in the sales gas or sales oil streams and not burned as fuel gas or flared. The VGR also burns some of the flash gas as fuel, which reduces the total amount of sales gas used on site for fuel gas. These results demonstrate that the VGR reduces the VOC that must be flared.

In addition to the impacts on VOC control, the economic performance of the separators was also evaluated to ensure that overall production revenues were not adversely impacted (e.g., by shifting hydrocarbons from oil sales to lower value gas sales). Raw field test data showed lower total sales oil and gas revenue generated by the VGR than the Dual Coil separator in the first test and higher total revenue for the VGR in the second test. The wells' overall oil and gas production rates are the dominant factor in these results. After normalizing the field data on a per pound of hydrocarbon produced by the wells basis, the VGR generated 1.0% less revenue than the Dual Coil in the first field test and 0.8% more revenue than the Dual Coil in the second test. The differences in the non-normalized oil production rates for both tests and in the non-normalized gas production rates in the first test were less than 95% confidence intervals for the difference in population means, so these differences are not statistically significant. In conclusion, the

field data showed that any differences in the economic performance were too small to measure directly in the field.

Some additional results and conclusions from the field testing are summarized below:

- In both field tests, the VGR resulted in more of the produced hydrocarbons being sold as oil or gas (indicating an average of 99.1% of hydrocarbons sold as oil or gas with VGR vs. 98.4% with Dual Coil on a mass basis).
- In both field tests, the VGR reduced the amount of gas generated in the storage tank and sent to the flare by about 1.0 Mscfd (43%).
- In both field tests, the VGR reduced fuel consumption by about 0.7 Mscfd (71%).
- Analytical samples collected during the evaluation showed no significant difference in composition of sales gas or sales oil between the VGR and the Dual Coil.
- The VGR produced slightly richer heating value (4.5%) flare gas on average, but there was a good deal of variation in the individual samples.
- No significant operational problems were encountered with the VGR or with the Dual Coil separators during the field evaluation.

Evaluation of Burner Designs

Burners, or enclosed flares as they are also referred to in industry, are commonly used to control storage tank vapor emissions at low production sites (e.g., tens of barrels per day). A fleet of several hundred 20" diameter burners is currently installed at Noble's Weld County production sites. Capacity limitations of this unit may require that multiple units be installed at higher producing wells, so this project included an effort to develop a cost-effective burner with a larger capacity, as well as to develop a surge bottle to extend the range of the 20" burner by reducing the peak flow rates.

A typical 20" burner has an estimated capacity of 14.0 Mscfd at 16 oz/in² (1 psig) inlet pressure. If peak flash gas rates exceed this rate for very long, pressure builds on the storage tanks and can eventually result in pressure relief valves allowing the tank to vent directly to the atmosphere. In Figure 4, shown earlier, a 20" burner is shown to the right of the large 48" diameter burner.

A larger 36" diameter burner was tested extensively in February and March 2007. This prototype burner initially had problems with severe vibration at certain ranges of inlet pressures during oil production cycles. Problems with visible smoke were also encountered. The vibrations, or fluttering as it is sometimes described, indicate flame instability at the burner tips. This instability is often caused by a shortage of air that causes the flame to alternately burn and extinguish in rapid pulses. A combustion expert witnessed field tests and recommended commercially available venturi burner tips and other changes to get more air into the burner. The challenge was getting enough air to mix with very rich gas that is at or near its dew point. The problem was even more difficult to solve in this application because the inlet gas did not have sufficient pressure to use as a motive force for air mixing, and electricity to run an air blower was not available. The recommended changes likely would have resulted in a unit cost for the burner that exceeded project goals.

Shortly after testing the 36" burner, another vendor was identified that had a 48" diameter enclosed flare demonstration unit that was immediately available for testing. Given the minimal costs to the project for testing the larger burner, its immediate availability and its potential to process more gas given the larger diameter, the project team moved forward with a test of the 48" diameter enclosed flare. The 48" burner was shown earlier in Figure 4.

Testing of the 48" flare prototype began in March 2007. The first round of testing revealed several problems. First, the 48" burner had significant vibration problems, although they were not as severe as those with the 36" diameter burner. Second, the stack temperatures exceeded acceptable temperatures for

the galvanized stacks used on the burners. Effectively, the burner configuration released too much heat for this size of enclosed flare. The gas rate and the heat release must be managed carefully to prevent overloading the unit. Also, occasional faint smoke was visible at very low inlet pressures, which are most likely to occur at either startup or shutdown of any given operational cycle and are not acceptable from an air quality perspective.

The vendor made several modifications to address the operational problems and delivered a revised prototype later in March 2007. The vendor reconfigured the burner manifold to reduce the maximum firing rate. The vendor also added a refractory blanket lining inside the galvanized metal stack. This provided the required temperature protection for maximum firing rates with metal galvanized stacks while keeping unit costs lower than alternative solutions such as stainless steel stacks or stainless steel-lined carbon steel stacks. A drawback of the refractory blanket design is that any gaps in the refractory could lead to failure of the galvanized metal stack. To address this concern, a minimum 1" overlap was specified at each seam of the heat blanket in order to protect the metal outside the heat blanket. The reconfigured burner manifold and the refractory liner addressed the high-temperature problems. To address the vibration problems, spring-loaded valves were placed in the burner manifolds to limit flow based on inlet pressure to the flare. Coupled with adjustments to damper settings on the air intakes, these changes effectively solved the vibration problems. The best solution identified for the smoking problem is to install a regulating valve that will only allow vapors to flow from the storage tank to the flare after a minimum pressure has been reached. Testing has been conducted to determine the optimum check valve and check valve orientation for this application.

Testing of Surge Bottles and Slug Catchers

As described earlier, wells at many of Noble's sites flow intermittently with the aid of a wellbore plunger. The fluctuation in fluid delivery rate to the separation equipment presents an additional challenge for controlling emissions because the peak as well as the average flows must be considered in design and operation. Several strategies may mitigate the negative impacts of flow variations on flashing losses. For example, slug catchers may be installed between the well and separations equipment. Additionally, surge bottles with appropriate controls may be installed between the separation equipment and the atmospheric storage tanks. The slug catchers and surge bottles provide a buffer for the separation and control equipment and reduce capital costs because the separation and control equipment may be sized for less than the peak flow rate. Each of these strategies is described in this subsection.

Surge Bottle Description

At many of Noble's production facilities, production flow rates cycle as low volume wells with plungers come on- and off-line. The fluctuation in feed flow rates to the site separations equipment causes operational challenges. Adding a vertical pressure vessel (e.g., "surge bottle") between upstream separation equipment and the atmospheric storage tank can reduce the amount of vent gas to be treated and thus reduce the size and cost of the downstream control device (e.g., a flare). The surge bottle also provides additional oil revenue because a larger fraction of the hydrocarbon feed remains in the liquid phase.

Figure 7 shows a schematic for a surge bottle. Liquids and gases from upstream separations equipment enter the pressure vessel. Liquids and gases accumulate in the pressure vessel during the course of the well cycle. Once pressure in the surge bottle exceeds a predetermined high pressure set point, vapors from the pressure vessel are routed to the control device at a controlled flow rate until the vessel's pressure decreases to a predetermined low pressure set point, after which time the gas flow to the control device is stopped. Liquids produced during a well cycle are kept in the surge bottle while pressure in the vessel is lowered by venting gas to the control device. This prevents high pressure liquid from flashing to

the storage tank, which results in a lower peak rate and a lower total amount of vapor formed over the cycle in the storage tank. Additionally, the oil production rate increases because more hydrocarbons remain in the liquid phase and the lower vent gas volume strips out a smaller amount of heavier hydrocarbons.

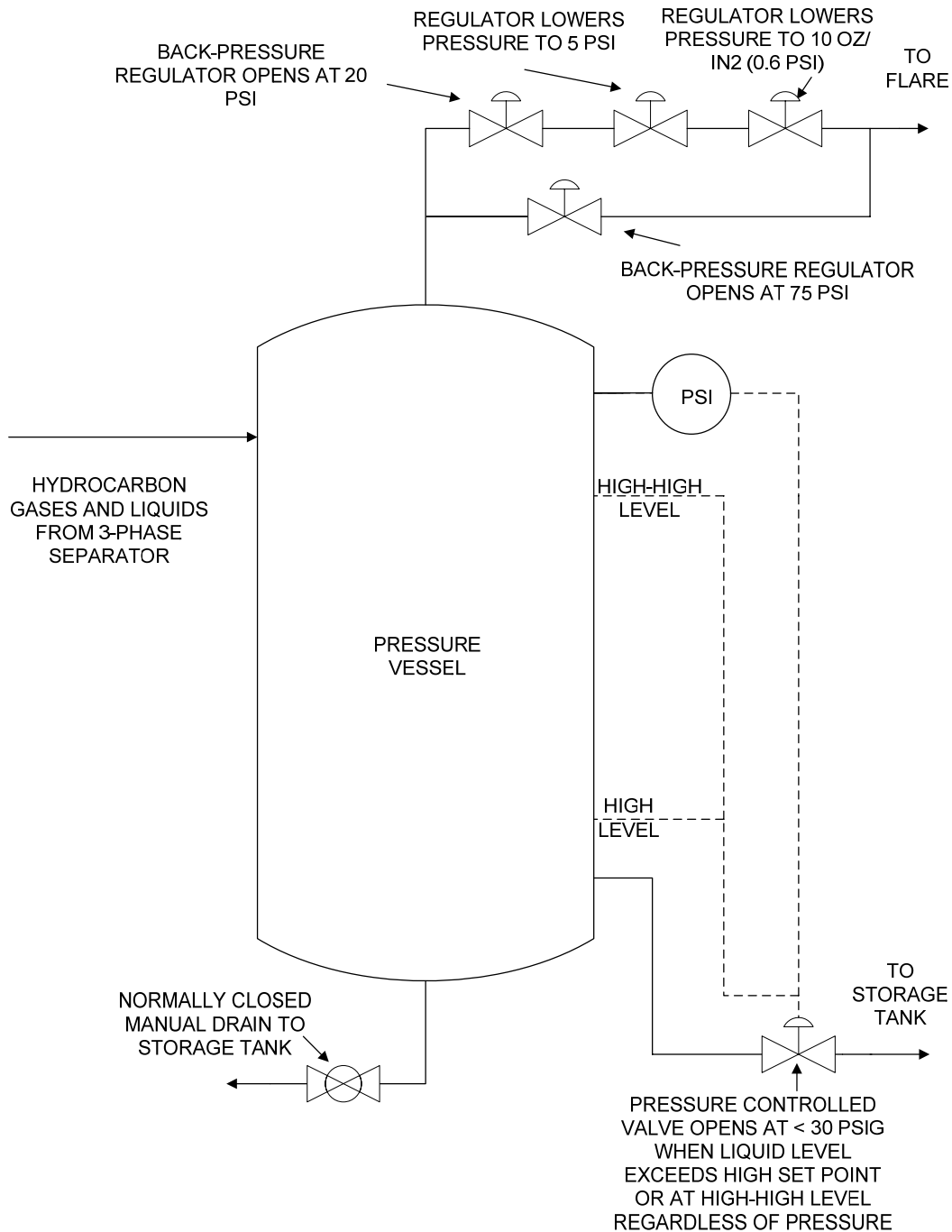


Figure 7 - Surge Bottle Schematic

Controls are provided that prevent discharge of liquids from the surge bottle unless the pressure is below a predetermined set point. The control set up maintains a liquid seal in the bottom of the vessel that

prevents vapors from going from the bottom of the vessel to the storage tank. In order for liquids to drain from the surge bottle to the storage tank under normal operating conditions, the liquid level in the surge bottle must be greater than the level set point, and the pressure in the surge bottle must be lower than the pressure set point. A second (high-high) level control setting in the bottle drains liquid from the bottle to the storage tank regardless of pressure in the bottle when the high-high liquid level is reached. This prevents the surge bottle from overflowing with liquid. Pressure controls that allow vapor and liquid to leave the surge bottle must operate at set points approximately 10 psi apart; therefore, settings must be selected carefully in order to obtain the full benefits of the surge bottle.

Surge Bottle Testing

Field testing of prototype surge bottles modified from existing pressure vessels showed that the surge bottle capacity must hold the entire production volume from a given well cycle for best performance in reducing or preventing venting from the storage tank. Additionally, the flare must bleed pressure off the surge bottle before the surge bottle becomes liquid full and before the back-pressure relief valve set point pressure is exceeded.

Over the course of the field testing, the control system was optimized to provide maximum system performance with simple controls that are readily available in oilfield service supply shops and to have fail-safe operation in the event that the surge bottle capacity was exceeded. The optimized control system was described in the previous subsection, Surge Bottle Description. As with other oilfield service equipment in these locations, the surge bottle is designed for unattended operation and does not require electricity. The peak oil production rate that can be effectively handled is limited by the volume of the surge bottle. Practical limitations of the physical size of the surge bottle are determined by transportation, installation and servicing requirements.

Repeated field tests of a 36" diameter, 8' seam-to-seam height surge bottle shown in Figure 8 showed that 2.5 to 3.0 bbl per well cycle (15 to 30 min) was the maximum oil production that could be successfully contained without exceeding the set point that relieves gas pressure in the surge bottle to the storage tank. Variation in well cycle production rates (in bbl/min) was a main factor leading to the variation in the volume of oil the surge bottle could hold in the field tests. Control tests showed that the peak vapor formation rates were reduced by using the surge bottle.

Trimeric performed process simulations to estimate the amount of oil per cycle that the surge bottle could hold and found good agreement with the field data. The simulations predicted the impact of operating temperature, flare capacity, duration of oil production per cycle and composition of gas remaining in the surge bottle from the previous cycle. As shown in Table II, the base case showed that a 2.7 bbl cycle that lasted 30 minutes could be held by the surge bottle. Varying conditions studied in the simulations gave a range of 2.0 to 4.1 bbl per well cycle as the maximum capacity of the surge bottle.



Figure 8 - 36” Diameter, 8’ Seam-to-Seam Surge Bottle

Table II - Summary of Simulated Surge Bottle Capacity for Varying Conditions

Case # and Description	Flash and Surge Temperature, °F	Gas to Burner, Mscfd	Duration of Surge, minutes	Composition of Gas in Surge Bottle at Start of Cycle	Surge Volume, bbl
1 - base	100	10.4	30	60 % C1, 30 % C2, 10 % C3	2.7
2 - higher temperature	120	10.4	30	60 % C1, 30 % C2, 10 % C3	2.0
3 - 20 % higher burner rate	100	12.48	30	60 % C1, 30 % C2, 10 % C3	3.4
4 - 20 % slower duration of surge	100	10.4	36	60 % C1, 30 % C2, 10 % C3	3.4
5 - 20 % lower burner rate	100	8.3	30	60 % C1, 30 % C2, 10 % C3	2.0
6 - 20 % faster duration of surge	100	10.4	24	60 % C1, 30 % C2, 10 % C3	2.0
7 - initial bottle composition - methane	100	10.4	30	100 % C1	2.2
8 - initial bottle composition - propane	100	10.4	30	100 % C3	4.1

Surge Bottle Economic Performance

Process simulations were also used to estimate the economic impacts of using the surge bottle. In addition to allowing VOC emission control devices to be sized for smaller peak flows of gas, the surge vessel also increases oil production. Trimeric ran process simulations for three field test sites to estimate the economics of the incremental oil production resulting from the surge vessel operation. Trimeric ran simulations for several feed compositions both with and without a surge bottle located between the separation equipment and the atmospheric storage tank. As with other simulations, Trimeric used WinSim Design II v.9.43, and the Peng Robinson equation of state was selected as the thermodynamic model. For the three sites that were modeled, the simulation results indicate that oil production could be improved by 2 to 3 percent, resulting in short economic payback periods of one year or less.

Slug Catcher Description

Another method to reduce peak flows and associated design requirements for VOC control is to employ a slug catcher upstream of the separators. Early in 2007, Trimeric and Noble engineers began discussing the concept and preparing engineering drawings for a slug catcher prototype. The prototype slug catcher is essentially a horizontal pipe sized to collect the volume of the maximum slug size. The prototype was sized to capture a 1 bbl slug of liquid. Figure 9 shows a schematic of the slug catcher. Produced oil, water, and gas enter one end of the slug catcher and the liquid and gas are separated by gravity. Gas continues to flow out the top of the exit pipe, but liquids are caught in the slug catcher. Liquids drain slowly through an external control valve designed to drain the slug catcher over a length of time sufficient to reduce the surge in liquid flow rate and thereby to reduce the resulting peak flash gas rate.

Slug Catcher Testing

A prototype slug catcher was fabricated and delivered to a test site in August 2007; however, plans for testing the slug catcher were put on hold to allow accelerated testing and development of the surge bottle. A potential drawback of the slug catcher is a high cost because the slug catcher must be rated for the high-pressure inlet conditions and requires a flanged end for maintenance. The slug catcher is also located upstream of the inlet three-phase separator, so water freezing during cold weather may be a greater operational problem that could lead to additional costs for insulation and heat tracing. One key benefit of the slug catcher is that the controls are very simple.

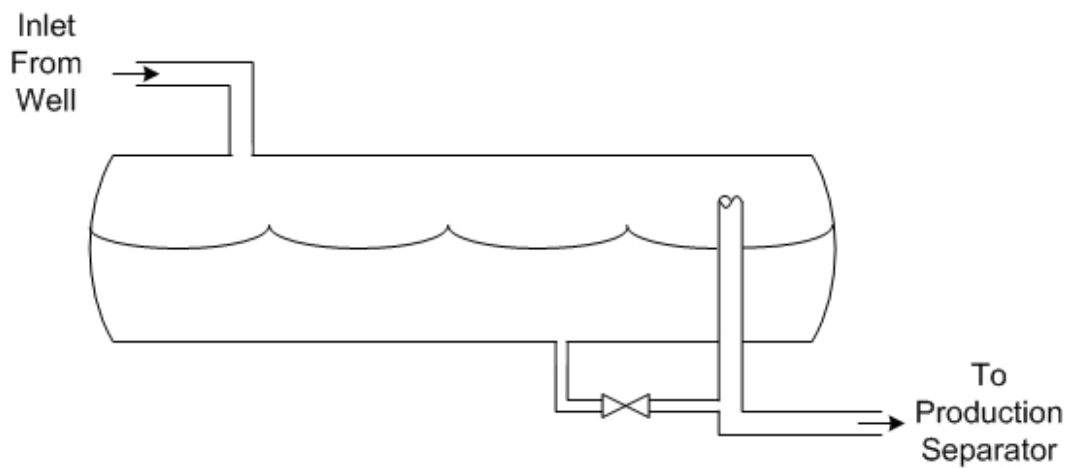


Figure 9 – Slug Catcher Schematic

Figure 10 is a picture of the prototype slug catcher, which is installed at a site with a current peak production rate of 2 to 3 bbl per well cycle. This is too high for testing the 1 bbl capacity slug catcher. Project personnel are monitoring the natural production decline at the site and testing is planned when the peak production rate drops to approximately 1 bbl per cycle.



Figure 10 – Slug Catcher in Field

Vapor Recovery Unit Testing

Two vapor recovery systems were evaluated in detail in the course of the project. The first, shown in Figure 5, is a packaged two-stage reciprocating compressor. The initial installation configuration had all low-pressure gas from the low-pressure separator of the HLP flashing to the storage tank and all vapors from the storage tank entering stage 1 of the VRU. Noble has more than 100 of these units in service at their Weld County production facilities. A goal of the project was to increase the throughput capacity of these VRUs.

The goal was accomplished by installing a surge bottle and sending vapors from the surge bottle directly to the second stage of the compressor. This reduced the load on the first stage of the compressor in two ways. First, the low-pressure gas from the HLP that would have gone to the storage tank and then to stage 1 of the VRU now went from the surge bottle directly to stage 2 of the VRU. Secondly, lower pressure liquid drained from the surge bottle to the storage tank, so fewer vapors were generated from flashing the oil to the storage tank.

The peak flow capacity of the VRU increased from 17 Mscfd in the original configuration to 32 Mscfd, with the surge bottle on-line and the with the surge bottle vapor routed directly to stage 2 of the VRU. Interestingly, the average amount of cumulative vapors collected by the VRU in a 24-hour period actually decreased from 7.5 Mscfd in the original configuration to 6.0 Mscfd with the surge bottle on-line.

The reduction in gas recovered with the surge bottle on-line indirectly confirms that the oil production rate is increased by using the surge bottle, as would be expected by adding an additional stage of pressure drop for flashing oil down to atmospheric pressure.

The second VRU evaluated in the project was a packaged unit that was integrated with a three-phase separator with two stages of pressure drop. The VRU portion of the unit had a single-stage compressor with two separate sources contributing to its inlet low pressure gas. The first source was vapor from the low-pressure separator. In fact, this system was designed to handle vapors from multiple two-stage separators so that gas from other low pressure separators at the site could be routed to the single VRU at the site. This approach improves the potential economic performance and payback period for the system. The other feed stream to the compressor was the storage tank vapors after they had been raised from near atmospheric pressure (< 1 psig) to approximately 25 psig by an eductor that used recycling glycol as the motive fluid.

This VRU was significantly more complex than the first VRU and other VOC control equipment evaluated in this project. An unacceptable number of system failures and reliability issues were encountered on two systems of this type that were evaluated for several months during this project. The manufacturer continues to work on the development and commercialization of this system. Economics could be quite favorable for this type of VRU system, provided that acceptable system reliability could be achieved and if other items such as favorable gas prices and the ability to sell the rich gas recovered by the VRU on a per Btu basis instead of on a per volume basis could be ensured. Payback periods of less than a year could be possible under the most optimal scenario.

CONCLUSIONS

The major conclusions of this paper are summarized below:

- The operation of production separators is closely linked to the optimal operation and design of associated VOC emission control equipment. Separators can be designed and operated to minimize the size of associated VOC controls while increasing revenue by reducing gas flared or burned as fuel gas.
- Field testing of separators to prove out the economics of various designs of operating strategies presents numerous operational challenges, especially for accounting and normalizing declining production rates.
- Proper sizing of flares based on peak flow rates is critical to achieving good emissions control. Peak flow rates of flash gases depend on the flow characteristics of production wells and the separator process configuration and operating conditions.
- Vapor recovery units offer the potential for improved economics and reduced emissions, but are more complex to operate than flares.
- Surge bottles and slug catchers, while introducing some additional complexity to production operations, are options for reducing peak flows and the size of emission control equipment. They also offer some potential for increased oil production due to improved oil/gas separation and reduced flashing losses.