Lessons Learned
from Natural Gas STAR Partners

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells

Executive Summary

When first completed, many natural gas wells have sufficient reservoir pressure to flow formation fluids (water and liquid hydrocarbon) to the surface along with the produced gas. As gas production continues, the reservoir pressure declines, and as pressure declines, the velocity of the fluid in the well tubing decreases. Eventually, the gas velocity up the production tubing is no longer sufficient to lift liquid droplets to the surface. Liquids accumulate in the tubing, creating additional pressure drop, slowing gas velocity, and raising pressure in the reservoir surrounding the well perforations and inside the casing. As the bottom well pressure approaches reservoir shut-in pressure, gas flow stops and all liquids accumulate at the bottom of the tubing. A common approach to temporarily restore flow is to vent the well to the atmosphere (well "blowdown"), which produces substantial methane emissions. The *U.S. Inventory of Greenhouse Gas Emissions and Sinks 1990—2008* estimates 9.6 billion cubic feet (Bcf) of annual methane emissions from venting of low pressure gas wells.

At different stages in the life of a gas well, various alternatives to repeated well venting can be deployed to move accumulated liquids to the surface. These options include:

- ★ Foaming agents or surfactants
- ★ Velocity tubing
- ★ Plunger lift, operated manually or with 'smart' well automation
- ★ Downhole pumps, which include reciprocating (beam) pumps and rotating (progressive cavity) pumps.

Natural Gas STAR Partners report significant methane emission reductions and economic benefits from implementing one or more lift options to remove accumulated liquids in gas wells. Not only are vented methane emissions reduced or eliminated, but these lift techniques can provide the additional benefit of increased gas production.

Economic and Environmental Benefits

Method for Reducing Natural Gas Losses	Volume of Natural Gas Savings and Incremental Production[1] (Mcf/well/year)	Value of Natural Gas Savings and Additional Production (Mcf/well/year)			Implementation Cost[1] (2010 $/Well)	Project Payback (years)		
		$3 per Mcf	$5 per Mcf	$7 per Mcf		$3 per Mcf	$5 per Mcf	$7 per Mcf
Use Foaming Agents	500 – 9,360	$1,500 - $28,080	$2,500 - $46,800	$3,500 - $65,520	$500 - $9,880	0 to 7	0 to 4	0 to 3
Install Velocity Tubing	9,285 – 27,610	$27,855 - $82,830	$46,425 - $138,050	$64,995 - $193,270	$7,000 - $64,000	0 to 3	0 to 2	0 to 1
"Smart" Well Automated Controls for Plunger Lift[2]	800 – 1,463[2]	$2,400 - $4,389	$4,000 - $7,315	$5,600 - $10,241	$5,700 - $18,000	1 to 8	1 to 5	1 to 4
Install Rod Pumps and Pumping Units[2]	973 – 2,040[2]	$2,919 - $6,120	$4,865 - $10,200	$6,811 - $14,280	$41,000 - $62,000	6 to 22	4 to 13	3 to 10

[1]Based on results reported by Natural Gas STAR Partners
[2]Does not include incremental gas production. Includes only potential gas savings from avoided well venting.

By avoiding or reducing well blowdowns, Partners report annual methane emissions savings that range from 500 thousand cubic feet (Mcf) per well to more than 27,000 Mcf/well. The benefit of increased gas production will vary considerably among individual wells and reservoirs, but can be substantial. For example, Partners report that increased gas production following plunger lift installation yielded as much as 18,250 Mcf per well.

Technology Background

Most gas wells will have liquid loading occur at some point during the productive life of the well. When this occurs, a common course of action to improve gas flow includes:

- ★ Shutting–in the well to allow bottom hole pressure to increase,
- ★ Swabbing the well to remove accumulated fluids,
- ★ Venting the well to the atmosphere (well blowdown),
- ★ Installing an artificial lift system.

'No-Emissions' Solutions for Liquid Loading in Gas Wells:

- ★ Foaming Agents/ Surfactants
  - – Low cost/ low volume lift method
  - – Applied early in production decline, when the bottom hole pressure still generates sufficient velocity to lift liquid droplets
- ★ Velocity Tubing
  - – Low maintenance, effective for low volumes lifted
  - – Somewhat expensive to acquire and install
  - – Often deployed in combination with foaming agents
- ★ Plunger Lift
  - – Long lasting
  - – Less expense to install and operate than a pumping unit
  - – Often, plunger lift cannot produce a well to its economic limit (abandonment).
  - – Challenging to operate effectively; requires more time and expertise to manage.
- ★ Rod Pumping Units
  - – Can be deployed in applications to remove greater liquid volumes than plunger lift.

Swabbing and "blowing down" a well to temporarily restore production can vent significant methane emissions, from 80 to 1600 Mcf/year per well. The process must be repeated as fluids reaccumulate, resulting in additional methane emissions. Operators may wait until well blowdown becomes increasingly ineffective before implementing some type of artificial lift. At this point, the cumulative methane emissions from a well could be substantial.

Natural Gas STAR Partners have found that applying artificial lift options early in the life of a well offers significant emissions savings and economic benefits. Each method for lifting liquid in a well has advantages and disadvantages for prolonging the economic life of a well. Total gas savings and methane emission reductions that result from reducing or eliminating well venting will vary for each well depending on flow line operating pressure, reservoir pressure, liquid volume, specific gravity and the number of blowdowns eliminated.

Fluid Removal Options for Gas Wells

Foaming Agents

The use of foam produced by surfactants can be effective for gas wells that accumulate liquid at low rates (Exhibit 1). Foam reduces the density and surface tension of the fluid column, which reduces the critical gas velocity needed to lift fluids to surface and aids liquid removal from the well. Compared to other artificial lift methods, foaming agents are one of the least costly applications for unloading gas wells. Foaming agents work best if the fluid in the well is at least 50 percent water. Surfactants are not

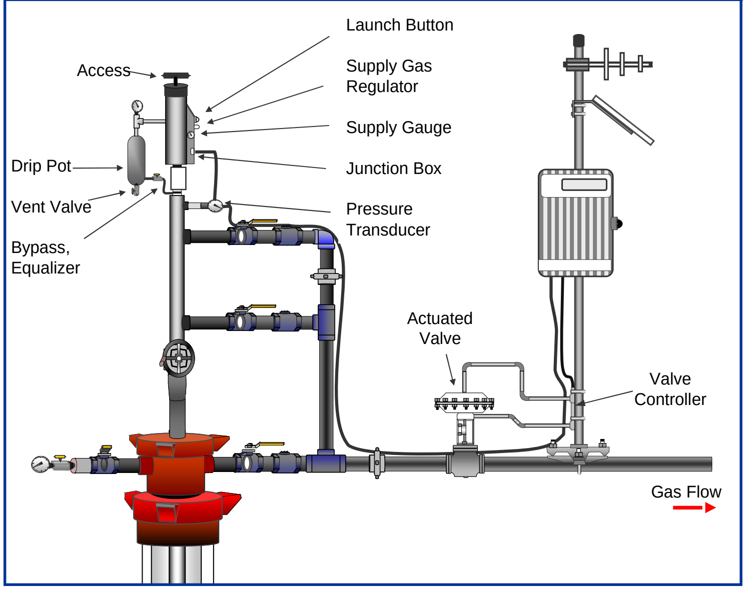
Exhibit 1: Liquid Foaming Agent

Source: S. Bumgardner, Advanced Resources International, inc.

effective for natural gas liquids or liquid hydrocarbons.

Surfactants are delivered to the well as soap sticks or as a liquid injected directly into the casing-tubing annulus or down a capillary tubing string. For shallow wells, the surfactant delivery can be as simple as the operator periodically pouring surfactant down the annulus of the well through an open valve. For deep wells, a surfactant injection system requires the installation of surface equipment, as well as regular monitoring. The surface equipment includes a surfactant or 'soap' reservoir, an injection pump, a motor valve with a timer (depending on the installation design), and a power source for the pump (Exhibit 2). No equipment is required in the well, although foaming agents and velocity tubing may be more effective when used in combination.

Exhibit 2: Soap Stick Launcher with Automatic Controller



Source: S. Bumgardner, Advanced Resources International, inc.

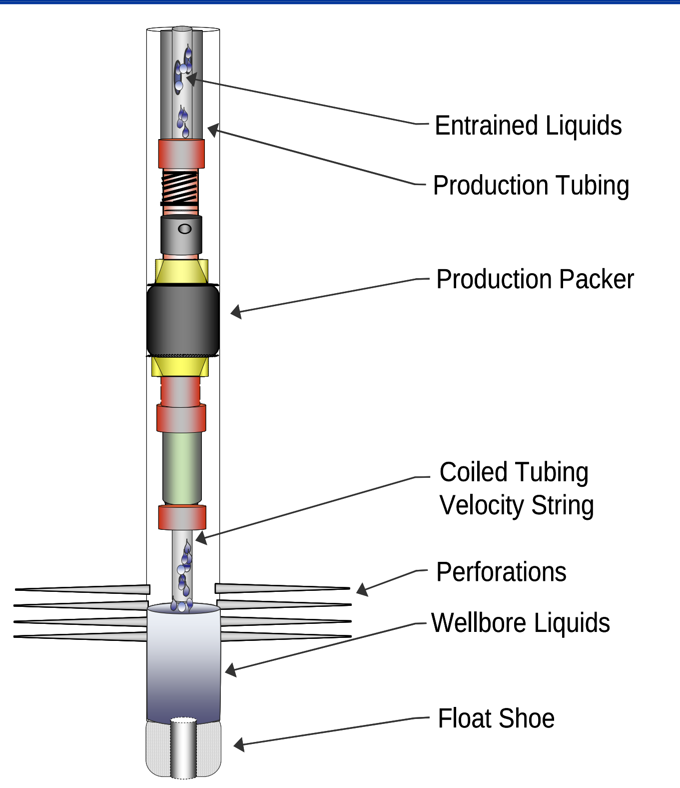
Electric pumps can be powered by AC power where available or by solar power to charge batteries. Other pump choices include mechanical pumps that are actuated by the movement of another piece of equipment or pneumatic pumps actuated by gas pressure. Different pump types have different advantages with respect to reliability, precision, remote operation, simplicity, maintenance frequency, efficiency, and equipment compatibility.

Velocity Tubing

The velocity at which gas flows through pipe determines the capacity to lift liquids. When the gas flow velocity in a well is not sufficient to move reservoir fluids, the liquids will build up in the well tubing and eventually block gas flow from the reservoir. One option to overcome liquid loading is to install smaller diameter production tubing or 'velocity tubing'. The cross-sectional area of the conduit through which gas is produced determines the velocity of flow and can be critical for controlling liquid loading. A velocity string reduces the cross-sectional area of flow and increases the flow velocity, achieving liquid removal while limiting blowdowns to the atmosphere.

Exhibit 3 shows that the conduit for gas flow up a wellbore can be either production tubing, the casing-tubing annulus or simultaneous flow through both the tubing and the annulus. In any case, a 2004 study estimated that gas velocity must be at least 5 to 10 ft/sec (300 to 600 ft/min) to effectively remove hydrocarbon liquids from a well, and at least 10 to 20 ft/ sec (600 to 1200 ft/min) to move produced water. As a rule of thumb, gas flow velocity of 1,000 feet per minute is needed to remove liquid. These figures assume used pipe in good condition with low relative roughness of the pipe wall.

Exhibit 3: Velocity Tubing



Source: S. Bumgardner, Advanced Resources International, inc.

The installation of a velocity string is relatively simple and requires calculation of the proper tubing diameter to achieve the required velocity at the inlet and outlet pressures of the tubing. Velocity tubing to facilitate liquid removal can be successfully deployed in low volume gas wells upon initial completion or near the end of their productive lives. Candidate wells include marginal gas wells producing less than 60 Mfcd. Installation of velocity tubing requires a well workover rig to remove the existing production tubing and place the smaller diameter tubing string in the well.

Coiled tubing may also be used, allowing for easier installation and the application of a greater range of tubing diameters as small as 0.25 inches. Coiled tubing can be applied in wells with lower velocity gas production due to better relative roughness characteristics of the tubing and the absence of pipe joint connections. Studies indicate that seamed coiled tubing provides better lift characteristics due to the elimination of turbulence in the flow stream because the seam acts as a "straightening vane".

Plunger Lift with 'Smart' Well Automation

Plunger lifts are commonly used to lift fluids from gas wells. A plunger lift system is a form of intermittent gas lift that uses gas pressure buildup in the casing-tubing annulus to push a steel plunger and a column of fluid above the plunger up the well tubing to the surface. Exhibit 4 shows a conventional plunger lift installation on a gas well.

Exhibit 4: Plunger Lift

Source: Chesapeake Energy

The operation of a plunger lift system relies on pressure buildup in a gas well during the time that the well is shut-in (not producing). The well shut-in pressure must significantly exceed the sales line pressure in order to lift the plunger and load of accumulated fluid to the surface against the sales line backpressure. A companion Lessons Learned paper, *Installing Plunger Lift Systems in Gas Wells,* discusses the installation, gas savings and economics of plunger lift systems. The focus of the present Lessons Learned paper are the incremental gas savings obtained from installing 'smart' automation systems to better manage the operation of plunger lift installations on a field-wide or basin-wide scale.

Most plunger systems operate on a fixed time cycle or on a preset differential pressure. Regardless of activation system (manual, fixed time cycle, or preset pressure differential), a valve mechanism and controller at the surface cause gas volume and pressure to build up in the wellbore initiating the plunger release cycle. At this point, the surface valve closes and the plunger drops to the bottom of the well. Once adequate pressure is reached, the surface valve opens and the plunger rises to the surface with the liquid load. Insufficient reservoir energy, or too much fluid buildup can overload a plunger lift. When that occurs, venting the well to the atmosphere (well blowdown) instantaneously reduces the backpressure on the plunger and usually allows the plunger to return to the surface.

Automated control systems optimize plunger lift and well unloading operations to prevent overloading (plunger cannot overcome backpressure and rise to the surface) and underloading (plunger rises to quickly, possibly damaging equipment) therefore reducing or eliminating well venting. "Smart" automated control systems combine customized control software with standard well control hardware such as remote terminal units (RTUs) and programmable logic controllers (PLCs) to cycle the plunger system and lift fluids out of the tubing. The artificial intelligence component of a smart automation system monitors the tubing and sales line pressures and allows the PLC to "learn" a well's performance characteristics (such as flow rate and plunger velocity) and to build an inflow performance relationship (IPR) curve for the well. The frequency and duration of the plunger cycle is then modified to optimize well performance.

Data analysis combined with wellhead control technology is the key to an effective gas well "smart" automation system. A smart automation system stores historical well production data allowing the program to learn from experience by monitoring and analyzing wellhead instrument data. The control system relays wellhead instrument data to a central computer, tracks venting times, and reports well problems and high-venting wells, all of which allow custom management of field production.

The components of a smart well automation system that must be installed on each gas well include:

- remote terminal unit with PLC,
- tubing and casing transmitters,
- gas measurement equipment,
- control valve, and
- plunger detector.

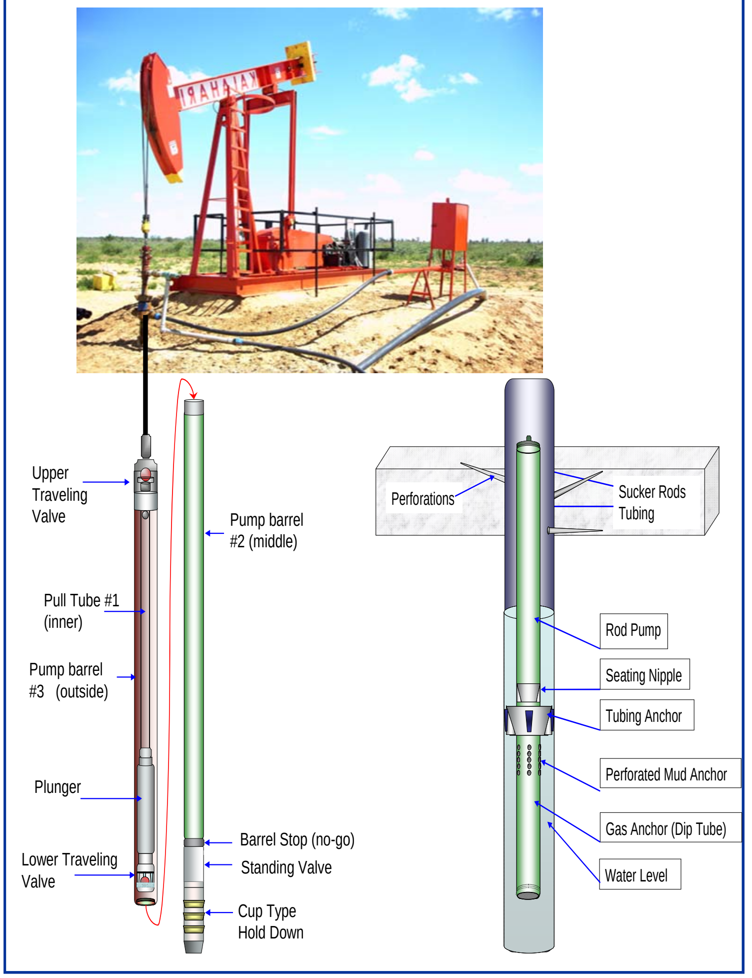
Automated controllers at the wellhead monitor well parameters and adjust plunger cycling. These typically operate on low-voltage, solar batteries. Exhibit 5 illustrates typical wellhead equipment and telemetry for plunger lift automated control systems. A host system capable of retrieving and presenting data is also required for continuous data logging and remote data transition. Operators configure all controls and send them to the RTU from the host system. Engineering time is needed to customize the control software and optimize the system. Field operating practices and protocols must be flexible to quickly address well performance deficiencies and operating problems.

Partners have found that optimized plunger lift cycling to remove liquids can decrease the amount of gas vented by up to 90+ percent. Methane emission savings from reduced well venting is a significant benefit that can add up to huge volumes when applied on a field or basin scale.

Exhibit 5: Typical Wellhead Equipment and Telemetry for Automated Control Systems for Plunger Lift

Source: BP

Exhibit 6: Diagram of a Sucker Rod Pump and Pump Jack



Source: S. Bumgardner, Advanced Resources International, inc.

Rod Pumps and Pumping Units

A downhole positive displacement, reciprocating rod pump with surface pump unit can be deployed in the later stages of a well's life to remove liquids from the wellbore and maximize production until the well is depleted (Exhibit 6). Pumping units can be installed when there is insufficient reservoir pressure to operate a plunger lift. The units can be manually controlled by the field pumper, or very low volume wells may be operated with a timer.

Pumping units not only eliminate the need to vent the well to unload fluids but also extend the productive life of a well. Methane emissions can be further reduced by operating pumping units with electric motors, rather than natural gas-fueled engines. The annual fuel requirement for a typical pumping unit is approximately 1,500 Mcf per unit, of which 0.5 percent is emitted as unburned methane (8 Mcf per unit per year).

A well workover rig is required to install the downhole rod pump, rods, and tubing in the well. Field personnel must be trained for rod pump operations and proper maintenance of the surface equipment. Excessive wear of the rods and tubing can be a major expense for rod pump applications where solids are produced or down hole corrosion is a problem.

A common problem with reciprocating pumps in gas wells is gas locking of the rod pump valves, which prevents the pump from delivering fluid to the surface at the design rate. The presence of free gas in the subsurface sucker rod pump decreases the volumetric pump efficiency and can prevent the pump from lifting fluid. This is not a problem found in progressive cavity pumps as there are no valves to gas lock.

Economic and Environmental Benefits

Implementation of fluid removal options and artificial lift provide economic and environmentally beneficial alternatives to well blowdown. The major benefit of the various fluid removal options is extending the productive life of a well. The full scope of environmental and economic benefits depend on the type of artificial lift system and the remaining productive capacity of the well. Several benefits described below, are realized with the progressive application of fluid removal options in gas wells.

- ★ **Improved gas production rates and extended well life.** Fluid removal and artificial lift systems conserve reservoir energy and boost gas production. Regular fluid removal generally extends the economic life of declining wells resulting in more continuous gas production, improved gas production rates, and incremental ultimate recovery.
- ★ **Reclaims vented gas to sales.** Avoiding well blowdown reclaims the value of gas that would otherwise be vented to the atmosphere.
- ★ **Reduced pollution.** Eliminating well blowdown and gas venting eliminates a significant source of methane and other air pollutant emissions.
- ★ **Lower well maintenance costs and fewer remedial treatments.** Overall well maintenance costs can be reduced by eliminating the cost of a workover rig for swabbing wells. Other savings occur when well blowdowns are significantly reduced or eliminated.

Four Steps for Evaluating Artificial Lift Options:

1. **Determine the technical feasibility of various artificial lift options.**
2. **Determine the cost of various options.**
3. **Estimate the natural gas savings and production increase.**
4. **Evaluate and compare the economics of artificial lift options.**

Decision Process

The decision to implement any type of liquid removal option during the life-cycle of a gas well should be made when the value of the estimated incremental gas production exceeds the cost of the fluid removal option. When one fluid removal approach becomes ineffective and uneconomic, another can be deployed. If venting a well is the current fluid removal approach, the application of foaming agents, velocity tubing or plunger lift should be evaluated before well blowdowns become too frequent, less effective and costly. Natural Gas STAR Partners can use the following decision process as a guide to evaluate the application, safety, and cost effectiveness of fluid removal and artificial lift installations.

Step 1: Determine the technical feasibility of a fluid removal option or artificial lift installation.

Various data and criteria should be evaluated to select a fluid removal approach that is both technically feasible and cost effective. These data include IPR (inflow performance relationship) curves; reservoir pressure; gas and fluid production flow rates; fluid levels in the well; the desired flowing bottom hole pressure and casing pressure; production tubing size, the downhole condition of the well; other mechanical limitations of the well and production site; and the capabilities and training of field personnel.

Appendix A (Exhibit A1 and A2) shows the Turner relationship and Lee relationship between critical flow rate (critical gas velocity), and flowing pressure for various sizes of production tubing. If the relationship between flow rate and pressure falls below a line specifying a size of production tubing, a well will not flow liquids to the surface for the indicated tubing size. If flow rate vs pressure falls on or above the line for a specified tubing size, a well meets or exceeds the critical flow rate for the specified tubing size and the well is able to unload fluid to the surface. Exhibits A1 and A2 can be used as starting points to estimate whether a fluid removal or artificial lift option is likely to be effective. Following are some technical considerations that enter into the decision process for each fluid removal option:

- ★ **Foaming Agents.** Partners typically use foaming agents early in the life of gas wells when the wells begin to load with formation water and the liquid production rate is comparatively low. Foaming works best if the liquid in the wellbore is mainly water, and condensate content is less than 50 percent. Foaming agents may also be used in combination with other well treatments that reduce salt and scale build up, or may be applied in combination with velocity tubing.

- ★ **Velocity Tubing**. Velocity tubing strings are appropriate for natural gas wells with relatively small liquid production and higher reservoir pressure. Low surface pipeline pressure relative to the reservoir pressure is also necessary to create the pressure drop that will achieve an adequate flow rate. The depth of the well affects the overall cost of the installation, but is usually offset by the higher pressure and gas volume in deeper wells. Velocity tubing can also be a good option for deviated wells and crooked well bores. Rod pumped wells with deviation and or dog legs that become uneconomic due to high failure rates and servicing costs may also be candidates for velocity strings.

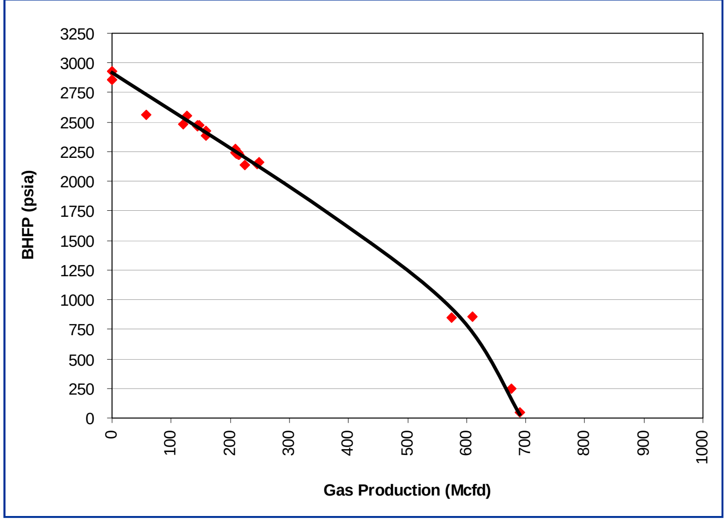
Indicators of Liquid Loading in Gas Wells:

1. Construct an IPR curve and evaluate the production efficiency of the well.
2. Monitor production curves for each well on a regular basis. Liquid loading is indicated if the curve for a normally declining well becomes erratic and the production rate drops.
3. Compute the critical gas velocity (flow rate) at which liquid can no longer be lifted in the tubing (see Appendix)
4. Critical velocity vs. flowing tubing pressure can be constructed for various tubing diameters.

Determining the feasibility of installing a velocity tubing string is relatively straightforward. An inflow performance relationship (IPR curve) is calculated to establish the flow regime in the well tubing, as shown in Exhibit 7. The diagram shown in Exhibit 7 illustrates the relationship between gas production and the bottom hole flowing pressure (BHFP). Gas flow is evaluated and the velocity relationships for various sizes of tubing are developed to determine the appropriate diameter for use in each well. As a rule of thumb, a gas flow velocity of approximately 1,000 feet per minute is the minimum necessary to remove fresh water. Condensate requires less velocity due to its lower density while more dense brine requires a higher velocity.

Once the velocity string is installed, no other artificial lift equipment is required until the reservoir pressure declines to the point that

Exhibit 7: Example of Inflow Performance Relationship Curve for Evaluating Fluid Removal Options



Source: S. Bumgardner, Advanced Resources International, inc.

velocities of 1,000 feet per minute are no longer possible in the tubing. The introduction of a foaming agent to the bottom of a tubing string will extend the effective life of a velocity string below the 1,000 feet per minute velocity required to lift water by reducing the density of the column that is lifted. This only applies to water lifted from the well tubing since condensate is not affected by a surfactant.

★ **"Smart" Well Automation of Plunger Lift.** Candidate wells for plunger lift generally do not have adequate downhole pressure for the well to flow freely into a gas gathering system. Like pumping units, plunger lifts are used to extend the productive life of a well. Installation is less expensive than rod pumps, but plunger lifts may be difficult to operate.

Conventional plunger lift operations rely upon manual, on-site adjustments to tune a plunger cycle time. When a plunger lift becomes overloaded, the well must be manually vented to the atmosphere to restart the plunger. A "smart" well automation system enhances plunger performance by monitoring parameters such as tubing and casing pressure, well flow rate and plunger cycle frequency (travel time). Data for each well are relayed to a host computer where operators review the data and address any performance deficiencies or operating problems. This helps to optimize plunger lift performance, improve gas production, and reduce well venting.

Optimum plunger lift performance generally occurs when the plunger cycle is frequent and set to lift the smallest liquid loads. Small liquid loads require lower operating bottom hole pressure, which allows for better inflow performance. As with velocity tubing, a desirable velocity for a plunger to ascend in tubing is in the range of 500 to 1,000 ft per minute.

★ **Pumping Units.** Rod pump installations for gas wells can be costly to install and operate, but can extend well life, increase ultimate recovery, increase profits and reduce methane emissions. A rod pumping application for gas wells must be carefully designed to ensure trouble-free installation of the pumping units, minimize installation costs, and maximize operating cost savings by reducing mechanical wear and the need for well servicing.

Technical considerations for a rod pump application include the amount of pump capacity required, the pump setting depth in the well, and the type and gravity of the fluid in the hole (brine, fresh water, hydrocarbon, hydrogen sulfide, carbon dioxide, etc.). These factors influence the components of a rod pump installation, including rod pump materials, rod string size and grade, pumping unit design, size of the prime mover (motor), pump speed and stroke length. Resources available for evaluating and designing rod pump applications for gas wells include American Petroleum Institute and various Society of Petroleum Engineers publications; commercial pumping unit vendors; and computer design models. In general, rod pump installations for gas wells have lower fluid volumes than for oil wells. Operating costs can be minimized by correctly sizing the artificial lift and pumping as slow as possible while maintaining a pumped-off condition. The use of pump-off controllers are also effective by matching the pump displacement to the volume of fluid entering the well bore.

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

Step 2. Determine the cost of fluid removal options.

Costs associated with the various fluid removal options include capital, start-up and labor expenditures to purchase and install the equipment, as well as ongoing costs to operate and maintain the systems.

★ **Foaming Agents.** Partners report upfront capital and start-up costs to install soap launchers ranging from $500 to $3,880 per well. Monthly cost for the foaming agent is $500 per well, or approximately $6,000 per year. As such, typical costs can vary between $500 and $9,880.

★ **Velocity Tubing.** One Partner reports total capital and installation costs of at least $25,000 per well, which includes the workover rig time, downhole tools, tubing connections and supervision. Another Partner has deployed velocity tubing in more than 100 wells and reports total installation costs ranging from $8,100 per well to $30,000 per well. Based on Partner experiences, typical costs will vary between $7,000 and $64,000 per well.

- **"Smart" Well Automation of Plunger Lift.** Two Partners report implementing "smart" automation systems to control plunger lift operations. One operation is fairly small, consisting of 21 wells. The second is a basin-wide deployment on more than 2,150 wells. Reported upfront costs for the smaller installation is $6,300 per well. Total cost over 5 years reported for the larger automation project is $12,200,000 or approximately $5,700 per well. Typical costs will vary between $5,700 and $18,000 depending on the complexity of the "smart" automation system. These costs would be incremental over the cost of installing a plunger lift system.

- **Pumping Units.** Capital and installation costs include the use of a workover rig and crew, for approximately one day, sucker rods, rod guides and pump costs, and the cost of the pumping unit and motor. Other start-up costs can include miscellaneous clean out operations to prepare the well to receive a down hole pump and sucker rods.

  Partners report that location preparation, well clean out, artificial lift equipment, and a pumping unit can be installed for approximately $41,000 to $62,000 per well. The reported average cost of the pumping unit alone appears to range from approximately $17,000 to $27,000. Most companies have surplus units in stock that can be deployed at the expense of transportation and repair, or may purchase used units.

Step 3. Estimate the savings from various fluid removal options.

The total savings associated with any of the fluid removal and artificial lift options include:

- Revenue from incremental increased gas production;
- Revenue from avoided emissions;
- Additional avoided costs such as well treatment and workover costs, and reduced fuel and electricity;
- Salvage value.

Revenue from Increased Production

The most significant benefit of deploying foaming agents, velocity tubing or a pumping unit is to extend the productive life of the well by decreasing the abandonment pressure of the reservoir and increasing the cumulative gas production. The benefit of automating a plunger lift system is to optimize the plunger cycle. Most of the increase in gas production is realized by the initial decision to install plunger lifts. Installing a 'smart' automated control system provides some incremental increase in gas production over a plunger lift system operated manually or by a timer, but the most significant benefit is the emissions avoided from repeated well blowdowns and the reduction in personnel time required at the well.

The fluid removal options are evaluated based on the incremental gas production predicted by well blowdowns. For wells that are not on production decline, the incremental gas production from installing velocity tubing or artificial lift can be estimated by assuming the average peak production after a well blowdown event represents the incremental peak production that will be achieved after the fluid removal option is implemented in the well.

The more common evaluation is for a well already experiencing production decline. In such a case, estimating incremental gas production from implementing a fluid removal/ artificial lift method is more complex and requires generating a new "expected" production and decline curve that would result from reducing the back pressure at the well perforations. This requires well-specific reservoir engineering analyses, a basic example of which is provided in Appendix B.

Once the incremental gas production from implementing a fluid removal approach is estimated, operators can

Exhibit 8: Gas Production Increase from Application of Foaming Agents — One Partner's Experience

- One Gas STAR Partner reports injecting foaming agent into 15 wells using soap sticks.
- Incremental gas production of individual wells increased an average of 513 Mcf per well per year.
- Annual incremental gas production for the entire project was 7,700 Mcf.
- Total cost for the project was $8,871 in 2010 dollars.
- At nominal gas prices ranging from $3.00/ Mcf to $5.00/ Mcf, the value incremental gas production ranges from approximately $23,100 to $38,500/ year and project payback occurs in 3 to 5 months.

calculate the value of the incremental gas and estimate the economics of the application. Exhibit 8 is an example of the potential revenue from increased gas production using foaming agents. Note that Exhibit 8 does not include other benefits such as avoided blowdown emissions and operations cost savings.

Revenue from Avoided Emissions

Emissions from venting gas to the atmosphere vary in both frequency and flow rates, and are entirely well and reservoir specific. The volume of natural gas emissions avoided by reducing or eliminating well blow-downs will vary due to individual characteristics such as sales line pressure, well shut-in pressure, fluid accumulation rate, and well dimensions (such as depth and casing and tubing diameters). Another key variable is an operator's normal practice for venting wells. Some operators put wells on automatic vent timers. Some wells are vented manually with personnel standing by monitoring the blow-down. In some cases, wells are open to vent and unattended for hours or days, depending upon the time it typically takes the well to clear liquids. The economic benefits of avoided emissions will vary considerably, and some projects will have significantly shorter payback periods than others.

Partner-reported annual emissions attributable to well blowdowns vary from 1 Mcf per well to several thousand Mcf per well, so methane emissions savings attributable to avoided emissions will also vary according to the characteristics and available data for the particular wells being vented. Exhibit 9 illustrates the range of avoided emissions reported by various Partners after applying specific fluid removal and artificial lift strategies in their operations.

Revenue from avoided emissions can be calculated by multiplying the sales price of the gas by the volume of vented gas. If well emissions have not been measured, they can be estimated. The volume of emissions from well venting can be estimated by constructing an IPR curve to predict the open flow potential of the well based on reservoir pressure, depth, tubular sizes, and fluid constituents. Other operator methods are discussed in Appendix C. The volume of gas released during well blow-down is dependent on the duration of the event, wellhead temperature and pressure, size of the vent line, the properties of the gas, and the quantity of water produced.

Four approaches to estimating well blow-down emissions are provided in Appendix C. None of the estimations discussed in Appendix C provide the "exact" result in an absolute sense, but they are accurate enough for effective management of producing gas wells. One emission estimation approach calculates well blow-down volume as a function of venting time, normal production rate, well volume and gas properties. Another approach uses

Exhibit 9: Comparison of Partner-Reported Costs and Emissions Savings for Fluid Removal/Artificial Lift Options

Fluid Removal Approach	Installation Costs ($/well)	Incremental Gas Production (Mcf/well/year)	Avoided Methane Emissions from Swabbing/ Blowdown[2] (Mcf/Well/Year)	Other Potential Cost Savings ($/well)
Use Foaming Agents	$500 - $9,880 *(installation of soap launcher);* $500/month *(surfactant)*	365 – 1,095	178 – 7,394	$2,000 *(eliminate well swabbing)*
Install Velocity Tubing	$7,000 - $64,000	9,125 – 18,250	146 – 7,394	$2,000 - $13,200 *(eliminate well swabbing & blowdown)*
"Smart" Well Automated Controls for Plunger Lift[1]	Partner reported average cost = $5,700 - $18,000	Not reported by Partners *(5,000 Mcf estimated for average U.S. gas well by assuming a 10-20% increase in production)*	Partner reported = 630 – 900 *(500 Mcf estimated for average U.S. well by assuming 1 % of annual production)*	$7,500 *(reduces labor cost to monitor plunger lift installations in the field)*
Install Rod Pumps and Pumping Units	$41,000 - $62,000	Not reported	769 – 1,612	$22,994 *(salvage value at end of well life)*

[1]Incremental cost, gas production and methane emissions savings for installation of automated plunger lift control system.
[2]Assumes methane content of natural gas at wellhead is 79 percent, unless reported otherwise.

pressure transient analysis to extrapolate gas flow rate from wellhead pressure. A final approach installs an orifice meter on a vent line and measures specific vent volume over time. The resulting vent rates expressed in Mcf/minute are averaged by producing formation and extrapolated from the initial subset of wells measured to the larger well population.

Avoided Costs and Other Benefits

Avoided costs and additional benefits depend on the type of fluid removal/ artificial lift system currently applied in the well and the new system to be deployed. These can include avoided chemical treatments, fewer well workovers, lower fuel costs and lower daily operations and maintenance costs. Partners report using foaming agents to replace well swabbing for a savings of approximately $2,000 annually per well. EPA's Natural Gas STAR Partners report that "smart" well automated control systems for plunger lifts have reduced the labor cost for field monitoring by approximately $7,500 per well. Velocity tubing eliminates well swabbing, well blowdowns and chemical treatments, the cost of which are reported to range from a few thousand to more than $13,000 per treatment.

Step 4. Evaluate the economics of fluid removal options.

Basic cash flow analysis can be used to compare the costs and benefits of the various fluid removal options. Exhibit 9 is a summary of the installation costs, gas savings and reduced methane losses associated with each fluid removal approach that have been reported by Natural Gas STAR Partners. Cash flow analyses based on Partner-reported experience and data are provided in Exhibit 10 for installing velocity tubing strings and in Exhibit 11 for "smart" well automated control systems for plunger lift.

Partner Experience

This section highlights specific experiences reported by Gas STAR Partners with the selected fluid removal options for gas wells.

Install Velocity Tubing Strings.

One Partner reported installation of velocity tubing in two Gulf Coast wells during 2008. Total installation cost in 2008 was $25,000 per well, which included a workover rig to remove and replace tubing, downhole tools, connections and supervision. Due to low inflation between years 2008 and 2010, the installation cost in 2010 dollars is only slightly higher than 2008.

The velocity tubing installation in these wells improved gas production by 25 Mcfd to 50 Mcfd, which equates to annual incremental gas production of approximately 9,125 Mcf to 18,250 Mcf per well. In addition, gas savings from eliminating well swabbing is 160 Mcf per year per well. Methane content of gas at the well head is 91 percent, so the estimated reduction in methane losses are 146 Mcf per well. Velocity tubing also eliminated annual swabbing costs of approximately $2000 per well per year. Exhibit 10

Exhibit 10: Economic Analysis of Velocity Tubing Installation Replacing Periodic Swabbing

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Value of Gas from Increased Production[1]		$36,500	$36,500	$36,500	$36,500	$36,500
Value of Gas from Avoided Emissions[2]		$640	$640	$640	$640	$640
Velocity Tubing Installation Cost	($25,000)					
Avoided Swabbing Cost		$2,000	$2,000	$2,000	$2,000	$2,000
Net Annual Cash Flow	**($25,000)**	**$39,140**	**$39,140**	**$39,140**	**$39,140**	**$39,140**

Internal Rate of Return = 155%
NPV (Net Present Value)[3] = $112,156
Payback Period = 8 months

[1] Gas valued at $4.00/ Mcf for 9,125 Mcf/well (25 Mcfd) due to increased gas production
[2] Gas valued at $4.00/Mcf for 160 Mcf /well of avoided gas emissions due to elimination of well swabbing
[3] Net present value based on 10 percent discount rate over 5 years

provides a cash flow analysis of this Partner's velocity tubing installation replacing well swabbing.

Install "Smart" Automated Control Systems on Plunger Lifts

Two Partners have applied "smart" well automated control systems at plunger lift installations. One Partner—BP—initiated an automation project in 2000, and in 2001 began installing automated plunger lift control systems across their San Juan Basin operations. BP justified the project based on gas and methane emissions savings resulting from a 50 percent reduction in well venting between 2000 and 2004. By 2007, BP implemented automated control systems for more than 2,150 wells equipped with plunger lift which resulted in average methane emissions savings of 900 Mcf per well. Total cost for the "smart" automation systems was $12.2 million. Total gas venting was reduced from approximately 4 billion cubic feet of gas per year (Bcf) to approximately 0.8 Bcf.

Another Natural Gas STAR Partner found that a substantially smaller application of "smart" automated controls for plunger lift can be similarly effective. An automated control system was implemented for 21 wells equipped with plunger lifts. Total gas savings are 16,800 Mcf per year, or 800 Mcf per well. Assuming a methane content of 79 percent, estimated annual methane emissions savings are 632 Mcf per well.

The wide range in upfront capital and installation costs for components of plunger lift automated control systems are indicated in Exhibit 9. The host computer and communication system can be quite costly ($50,000 to $750,000) depending upon the size of the project, but as more plunger lift-equipped wells are added, the unit cost for the automated control system is significantly reduced. The two Natural Gas STAR Partners report approximate unit costs for plunger lift automated control systems of $6,800 and $5,950 per well, respectively. Exhibit 11 provides a basic cash flow analysis of "smart" well automated control systems for plunger lift based on

Exhibit 11: Economic Analysis of "Smart" Well Automated Control Systems for Plunger Lift for Hypothetical Onshore Gas Field[1]

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Value of Gas from Increased Production[2]		$220,000	$220,000	$220,000	$220,000	$220,000
Value of Gas from Avoided Emissions[3]		$40,000	$40,000	$40,000	$40,000	$40,000
Install RTUs at Wells, $ ($11,000/well x 20 wells)	($220,000)					
Install Host Computer / Communication ($50K - - $750K)	($200,000)					
Avoided Labor Cost for Field Monitoring ($7500/well x 20 wells**)**		$150,000	$150,000	$150,000	$150,000	$150,000
Net Cash Inflow	**($420,000)**	**$410,000**	**$410,000**	**$410,000**	**$410,000**	**$410,000**

Internal Rate of Return = 94%
NPV (Net Present Value)[4] = $1,031,111
Payback Period = 12.3months

1 Assumes production from average US gas well is 50,000 Mcf/Year
2 Gas valued at $4.00/Mcf for 5,000 Mcf /well of increased gas production due to optimized plunger lift operation; equivalent to 10% of production for average US onshore gas well. Assumes 20 wells in project.
3 Gas valued at $4.00/Mcf for 500 Mcf of gas savings due to reduced well blowdown/venting; equivalent to 1% of production for average US onshore gas well. Assumes 20 wells in project.
4 Net present value based on 10 percent discount rate over 5 years

generic assumptions about potential increased gas production and methane emissions savings for the average onshore natural gas well in the United States.

Install Pumping Units on Wells Lifting Low Water Volumes

ConocoPhillips installed pumping units on 45 low-pressure gas wells in 2003 to remove low water volumes from the wells and prevent them from loading up. This installation eliminated routine venting of the wells for up to one hour per day. The primary benefit of installing pumping units on these wells is the incremental gas production gained by extending the productive life of the wells. The Partner reported gas savings of 973 Mcf per well from the elimination of well blowdowns as a secondary, but not insignificant, benefit. The pump jacks at this installation are powered by electric motors rather than natural gas engines, which contributes to fewer methane emissions and lower maintenance costs.

ConocoPhillips reported total gas savings of 43,780 Mcf for the project or approximately 973 Mcf per well per year. At a nominal gas price of $4.00 to $5.00/Mcf, this corresponds to savings of approximately $3,892 to $4,865 per unit, or $175,140 to $218,900 per year for the entire project consisting of 45 wells. Assuming a methane content of 79 percent, this project has reduced methane losses by 34,586 Mcf per year.

Total capital and installation costs for the downhole pumps and surface pumping units were estimated to be $62,000 per well in 2003 or the equivalent of $73,332 in 2010 dollars. The total cost in 2003 included $45,000 for site preparation, downhole equipment, and installation plus an average cost of $17,000 per pumping unit. The project was expanded in subsequent years. ConocoPhillips reported a total of 100 pumping units installed from 2005 through 2007. During this time, the average reported upfront installation cost declined to approximately $38,000 per unit in 2010 dollars. Assuming a nominal gas price of $4, the vented gas savings alone pays back the typical pumping unit installation for this project in less than 10 years.

Nelson Price Indexes

In order to account for inflation in equipment and operating & maintenance costs, Nelson-Farrar Quarterly Cost Indexes (available in the first issue of each quarter in the *Oil and Gas Journal*) are used to update costs in the Lessons Learned documents.

The "Refinery Operation Index" is used to revise operating costs while the "Machinery: Oilfield Itemized Refining Cost Index" is used to update equipment costs.

To use these indexes in the future, simply look up the most current Nelson-Farrar index number, divide by the February 2006 Nelson-Farrar index number, and, finally multiply by the appropriate costs in the Lessons Learned.

Lessons Learned

- For natural gas wells, a progression of fluid removal options are available to unload accumulated fluid, boost gas production, extend well life and reduce or eliminate the need for well venting.
- Options for removing accumulated wellbore fluids from gas wells range from relatively low cost application of surfactants, appropriate for wells with low fluid production and significant remaining reservoir energy, to installing pumping units and downhole rod pumps on wells with depleted reservoir pressure and significant water production.
- The best approach will depend on the where a well is performing along the continuum of its productive life.
- Well blowdown and swabbing can release large volumes of natural gas to the atmosphere, producing significant methane emissions and gas losses.
- Fluid removal approaches presented in this paper can reduce the amount of remedial work needed during the lifetime of a well, eliminate well blowdowns, and increase the ultimate recovery of the well while minimizing methane emissions to the atmosphere.
- If a well is in production decline, the fluid removal alternatives discussed here will increase gas production in most cases or at least arrest the decline.
- This increased gas production should be captured in analyses of cash flow and future economic benefit when evaluating fluid removal options for gas wells. In most cases, increased gas production is the primary benefit from implementing any or all of the fluid removal options.

★ Methane emissions and gas savings from the elimination of well venting is generally a secondary, but significant, benefit, which may cover all or most of the upfront installation costs for a fluid removal technology.

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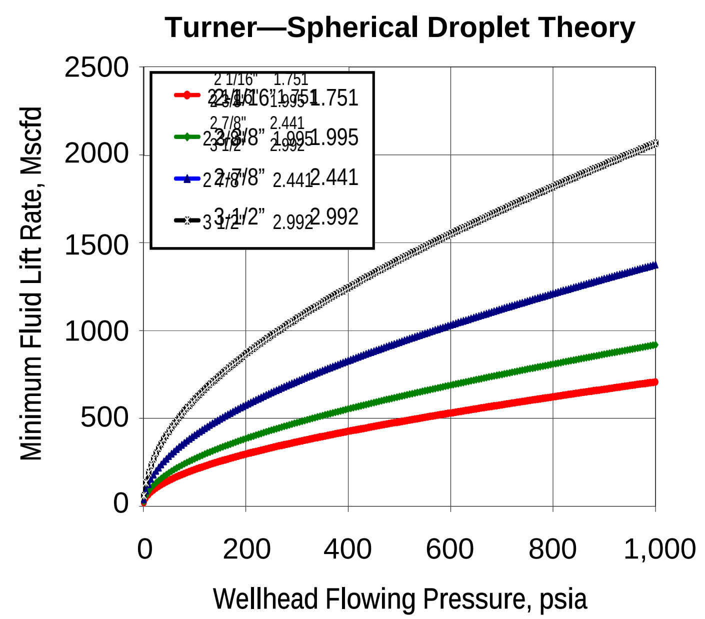
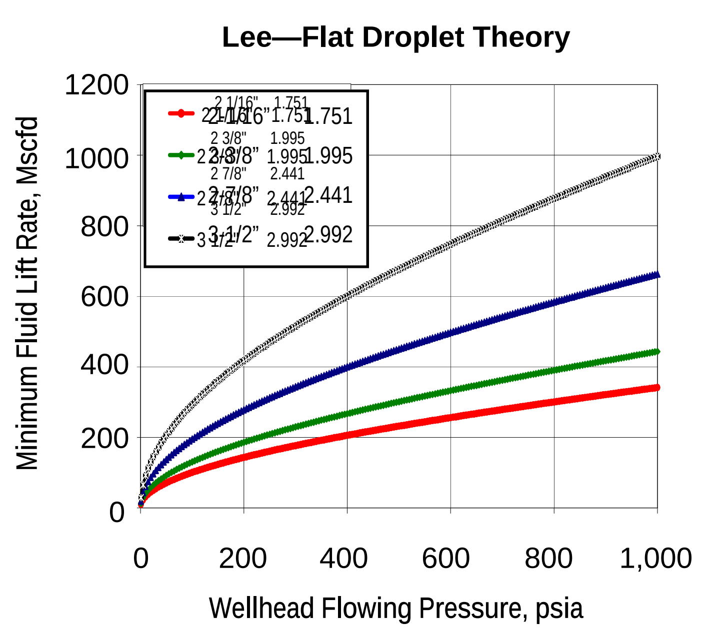
APPENDIX A: Estimating the Critical Flow Rate to Remove Liquids from Production Tubing

Exhibit A1: Turner Unloading Rate for Well Producing Water



Source: S. Bumgardner, Advanced Resources International, inc.

Exhibit A2: Lee Unloading Rate for Well Producing Water



Source: S. Bumgardner, Advanced Resources International, inc.

APPENDIX B: Estimating Incremental Production for Declining Wells

From Dake's Fundamentals of Reservoir Engineering (1978) the following analytical model can be used to estimate increased gas flow into a well in response to reducing back pressure on the perforations by removing accumulated liquids. The semi-steady state inflow equation is:

$$\mathbf{m(p_{avg})-m(p_{wf})=[(1422 \times Q \times T)/(k \times h)] \times [\ln(r_e/r_w)-3/4+S)] \times (8.15)}$$

Where,

$m(p_{avg})$ = real gas pseudo pressure average

$m(p_{wf})$ = real gas pseudo pressure well flowing

Q = gas production rate

T = absolute temperature

k = permeability

h = formation height

r_e = external boundary radius

r_w = wellbore radius

S = mechanical skin factor

Incremental production achieved by implementing various artificial lift options can be estimated by solving this equation for `Q' calculated for retarded flow with fluids in the hole (current conditions and current decline curve), and comparing to `Q' calculated for the condition of no fluids in the hole (artificial lift active and improved decline curve). This discussion is intended as a guide for estimating the potential impact of fluid removal alternatives, and is not a substitute for thorough reservoir engineering analyses of specific wells.

APPENDIX C: Alternate Techniques for Estimating Avoided Emissions When Replacing Blowdowns

Simple Vent Volume Calculation

A conservative estimate of well venting volumes can be made using the following equation:

Annual Vent Volume, Mscf/yr = (0.37×10^{-6})*(Casing Diameter^2)*(Well Depth)*(Shut-in Pressure)*# of Annual Vents)

Where, casing diameter is in inches, well depth is in feet and shut-in pressure is in psia. If the shut-in pressure is not known, a suitable surrogate is the casing pressure at the surface.

This is the minimum volume of gas that would be vented to atmospheric pressure from a well that has stopped flowing to the sales line because a head of liquid has accumulated in the tubing equal to the pressure difference between the sales line pressure and well shut-in pressure.

If the well shut-in pressure is more than 1.5 times the sales line pressure, as required for a plunger lift installation, then the volume of gas in the well casing at shut-in pressure should be minimally sufficient to push the liquid in the tubing to the surface in slug-flow when back-pressure is reduced to sales line pressure.

Partners can estimate the minimum time needed to vent the well by using this volume and the Weymouth gas-flow formula (worked out for common pipe diameters, lengths and pressure drops in Tables 3, 4 and 5 in *Pipeline Rules of Thumb Handbook*, Fourth Edition, pages 283 and 284). If a Partner's practice is to open and vent the wells for a longer time than calculated by these methods, the Annual Vent Volume calculated by this equation can be scaled up according to the ratio of the actual vent time versus the minimum vent time calculated using the Weymouth equation.

Natural Gas STAR Partner, BP, has reported three approaches to estimating well venting and completion emissions, which include: 1) a more detailed version of the vent volume calculation method above, 2) pressure transient analysis, and 3) installing an orifice meter on the vent line.

Detailed Vent Volume Calculation

The detailed vent volume calculation is a function of venting time, normal production rate, and "well blowdown value" that represents the volume of gas in a well under an assumption of line pressure.

**Vent Volume(Mcf) =
((Vent Time – 30 min)*(1/1440)* Production Rate) + (Well Blowdown Volume)**

**Well Blowdown Volume (Mcf) =
(well depth*3.1416*(casing diameter/2)^2) * ((tubing press + atmospheric press)/14.7) * (520/(Temp+460))/ Z/ 1000**

Variables:

- production rate, Mcf per day
- well depth, ft
- atmospheric pressure, psia
- shut-in tubing pressure, psig
- temperature of gas in pipeline, ^{o}F
- diameter of production casing, ft
- compressibility, Z

A limitation of the vent volume calculation method is that it does not account for either the volume or weight of a column of fluid in the wellbore at the time of venting.

Pressure Transient Analysis

This method is based on observations of wellhead pressure versus flow rate for a specific set of wells which are used to develop a linear expression of gas flow rate versus wellhead pressure. This relationship is then applied to pressure transient data during blowdown to extrapolate Mcf versus time for the venting period. All data are evaluated using pressure data analysis software to extrapolate total vented volumes based on the blowdown time, pipe diameter and the decline in well head pressure during the process. An advantage of this approach is that it accounts for choke flow and is tailored to specific wells. Limitations of the approach are that it fails to account for very large influx into the reservoir and the observations data set may not be representative of the formation. To make the data set more representative, it is recommended that the data include at least one point within the following 5 ranges:

- ★ $P \leq 25$ psia
- ★ 25 psia $< P \leq 60$ psia

- ★ 60 psia < P ≤ 110 psia
- ★ 110 psia < P ≤ 200 psia
- ★ 200 psia < P

Orifice Metering of Blow Down

For this approach, an orifice meter is installed on a vent line and flow rates are measured directly during blowdown. An advantage of this approach is the precision of the data that are obtained, potentially offering meaningful comparisons of vent volumes between well types, well completions or producing formations.

A limitation of the approach is that results obtained from a 'study population' or small subset of producing wells will likely be extrapolated to a larger field or producing area, and the original study wells may not be representative of field operations as a whole.

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EPA provides the suggested methane emissions estimating methods contained in this document as a tool to develop basic methane emissions estimates only. As regulatory reporting demands a higher-level of accuracy, the methane emission estimating methods and terminology contained in this document may not conform to the Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart W methods or those in other EPA regulations.