Lessons Learned

From Natural Gas STAR Partners

INSTALLING PLUNGER LIFT SYSTEMS IN GAS WELLS

Executive Summary

In mature gas wells, the accumulation of fluids in the well can impede and sometimes halt gas production. Gas flow is maintained by removing accumulated fluids through the use of a beam pump or remedial treatments, such as swabbing, soaping, or venting the well to atmospheric pressure (referred to as "blowing down" the well). Fluid removal operations, particularly well blowdowns, may result in substantial methane emissions to the atmosphere.

Installing a plunger lift system is a cost-effective alternative for removing liquids. Plunger lift systems have the additional benefit of increasing production, as well as significantly reducing methane emissions associated with blowdown operations. A plunger lift uses gas pressure buildup in a well to lift a column of accumulated fluid out of the well. The plunger lift system helps to maintain gas production and may reduce the need for other remedial operations.

Natural Gas STAR partners report significant economic benefits and methane emission reductions from installing plunger lift systems in gas wells. Companies have reported annual gas savings averaging 600 thousand cubic feet (Mcf) per well by avoiding blowdowns. In addition, increased gas production following plunger lift installation has yielded total gas benefits of up to 18,250 Mcf per well, worth an estimated $127,750. Benefits from both increased gas production and emissions savings are well- and reservoir-specific and will vary considerably.

Method for Reducing Methane Emmissons	Potential Gas Savings from Increased Gas Production and Avoided Emissions (Mcf/yr)	Value of Natural Gas Production and Savings ($)	Cost of Implementation ($/well)	Payback (months)
Install a plunger lift system	4,700 - 18,250[2] per well	$32,900 - 127,750	$2,591 - 10,363	2 - 14

[1] Value of gas $7.00/Mcf.
[2] Based on results reported by Natural Gas STAR partners.

This is one of a series of Lessons Learned Summaries developed by EPA in cooperation with the natural gas industry on superior applications of Natural Gas STAR Program Best Management Practices (BMPs) and Partner Reported Opportunities (PROs).

Technology Background

Liquid loading of the wellbore is often a serious problem in aging production wells. Operators commonly use beam lift pumps or remedial techniques, such as venting or "blowing down" the well to atmospheric pressure, to remove liquid buildup and restore well productivity. These techniques, however, result in gas losses. In the case of blowing down a well, the process must be repeated over time as fluids reaccumulate, resulting in additional methane emissions.

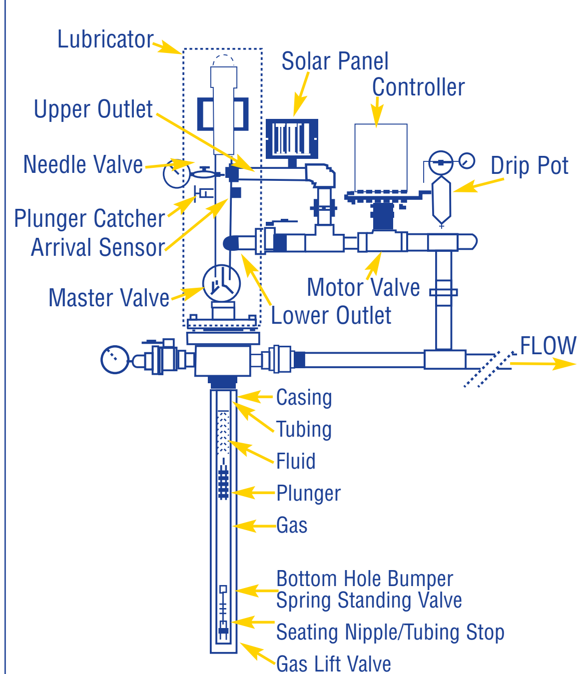
Plunger lift systems are a cost-effective alternative to both beam lifts and well blowdowns and can significantly reduce gas losses, eliminate or reduce the frequency of future well treatments, and improve well productivity. A plunger lift system is a form of intermittent gas lift that uses gas pressure buildup in the casing-tubing annulus to push a steel plunger, and the column of fluid ahead of it, up the well tubing to the surface. The plunger serves as a piston between the liquid and the gas, which minimizes liquid fallback, and as a scale and paraffin scraper. Exhibit 1 depicts a typical plunger lift system.

The operation of a plunger lift system relies on the natural buildup of pressure in a gas well during the time that the well is shut-in (not producing). The well shut-in pressure must be sufficiently higher than the sales-line pressure to lift the plunger and liquid load to the surface. A valve mechanism, controlled by a microprocessor, regulates gas input to the casing and automates the process. The controller is normally powered by a solar recharged battery and can be a simple timer-cycle or have solid state memory and programmable functions based on process sensors.

Operation of a typical plunger lift system involves the following steps:

1. The plunger rests on the bottom hole bumper spring located at the base of the well. As gas is produced to the sales line, liquids accumulate in the well-bore, creating a gradual increase in backpressure that slows gas production.

Exhibit 1: Plunger Lifts



2. To reverse the decline in gas production, the well is shut-in at the surface by an automatic controller. This causes well pressure to increase as a large volume of high pressure gas accumulates in the annulus between the casing and tubing. Once a sufficient volume of gas and pressure is obtained, the plunger and liquid load are pushed to the surface.
3. As the plunger is lifted to the surface, gas and accumulated liquids above the plunger flow through the upper and lower outlets.
4. The plunger arrives and is captured in the lubricator, situated across the upper lubricator outlet.
5. The gas that has lifted the plunger flows through the lower outlet to the sales line.
6. Once gas flow is stabilized, the automatic controller releases the plunger, dropping it back down the tubing.
7. The cycle repeats.

New information technology systems have streamlined plunger lift monitoring and control. For example, technologies such as online data management and satellite communications allow operators to control plunger lift systems remotely, without regular field visits. Operators visit only the wells that need attention, which increases efficiency and reduces cost.

Economic and Environmental Benefits

The installation of a plunger lift system serves as a cost-effective alternative to beam lifts and well blowdown and yields significant economic and environmental benefits. The extent and nature of these benefits depend on the liquid removal system that the plunger lift is replacing.

★ **Lower capital cost versus installing beam lift equipment.** The costs of installing and maintaining a plunger lift are generally lower than the cost to install and maintain beam lift equipment.

★ **Lower well maintenance and fewer remedial treatments.** Overall well maintenance costs are reduced because periodic remedial treatments such as swabbing or well blowdowns are reduced or no longer needed with plunger lift systems.

★ **Continuous production improves gas production rates and increases efficiency.** Plunger lift systems can conserve the well's lifting energy and increase gas production. Regular fluid removal allows the well to produce gas continuously and prevent fluid loading that periodically halts gas production or "kills" the well. Often, the continuous removal of fluids results in daily gas production rates that are higher than the production rates prior to the plunger lift installation.

★ **Reduced paraffin and scale buildup.** In wells where paraffin or scale buildup is a problem, the mechanical action of the plunger running up and down the tubing may prevent particulate buildup inside the tubing. Thus, the need for chemical or swabbing treatments may be reduced or eliminated. Many different types of plungers are manufactured with "wobble-washers" to improve their "scraping" performance.

★ **Lower methane emissions.** Eliminating repetitive remedial treatments and well work overs also reduces methane emissions. Natural Gas STAR partners have reported annual gas savings averaging 600 Mcf per well by avoiding blowdown and an average of 30 Mcf per year by eliminating workovers.

★ **Other economic benefits.** In calculating the economic benefits of plunger lifts, the savings from avoided emissions are only one of many factors to consider in the analysis. Additional savings may result from the salvage value of surplus production equipment and the associated reduction in electricity and work over costs. Moreover, wells that move water continuously out of the well bore have the potential to produce more condensate and oil.

Decision Process

Operators should evaluate plunger lifts as an alternative to well blowdown and beam lift equipment. The decision to install a plunger lift system must be made on a case-by-case basis. Partners can use the following decision process as a guide to evaluate the applicability and cost-effectiveness of plunger lift systems for their gas production wells.

Four Steps for Evaluating Plunger Lift Systems:

1. Determine the technical feasibility of a plunger lift installation;
2. Determine the cost of a plunger lift system;
3. Estimate the savings of a plunger lift; and
4. Evaluate the plunger lifts economics.

Step 1: Determine the technical feasibility of a plunger lift installation. Plunger lifts are applicable in gas wells that experience liquid loading and have sufficient gas volume and excess shut-in pressure to lift the liquids from the reservoir to the surface. Exhibit 2 lists four common well characteristics that are good indicators of plunger lift applicability. Vendors often will supply written materials designed to help operators ascertain whether a particular well would benefit from the installation of a plunger lift system. As an example, a well that is 3,000 feet deep, producing to a sales line at 100 psig, has a shut-in pressure of 150 psig and must be vented to the atmosphere daily to expel and average of three barrels per day of water accumulation. This well has sufficient excess shut-in pressure and would have to produce 3,600 scf per day (400 scf/bbl/1000 feet of depth times 3000 feet of depth, times 3 barrels of water per day) to justify use of a plunger lift.

Exhibit 2: Common Requirements for Plunger Lift Applications
★ Well blowdowns and other fluid removal techniques are necessary to maintain production.
★ Wells must produce at least 400 scf of gas per barrel of fluid per 1,000 feet of depth.
★ Wells with shut-in wellhead pressure that is 1.5 times the sales line pressure.
★ Wells with scale or paraffin buildup.

Step 2: Determine the cost of a plunger lift system. Costs associated with plunger lifts include capital, start-up and labor expenditures to purchase and install the equipment, as well as ongoing costs to operate and maintain the system. These costs include:

★ **Capital, installation, and start-up costs.** The basic plunger lift installation costs approximately $1,900 to $7,800. In contrast, installation of surface pumping equipment, such as a beam lift, costs between $26,000 and $52,000. Plunger lift installation costs include installing the piping, valves, controller and power supply on the wellhead and setting the down-hole plunger bumper assembly assuming the well tubing is open and clear. The largest variable in the installation cost is running a wire-line to gauge the tubing (check for internal blockages) and test run a plunger from top to bottom (broaching) to assure that the plunger will move freely up and down the tubing string. Other start-up costs can include a well depth survey, swabbing to remove well bore fluids, acidizing to remove mineral scale and clean out perforations, fishing-out debris in the well, and other miscellaneous well clean out operations. These additional start-up costs can range from $700 to more than $2,600.

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 that by the February 2006 Nelson-Farrar index number, and, finally, multiply by the appropriate costs in the Lessons Learned.

Operators considering a plunger lift installation should note that the system requires continuous tubing string with a constant internal diameter in good condition. The replacement of the tubing string, if required, can add several thousands of dollars more to the cost of installation, depending upon the depth of the well.

- ★ **Operating costs.** Plunger lift maintenance requires routine inspection of the lubricator and plunger. Typically, these items need to be replaced every 6 to 12 months, at an approximate cost of $700 to $1,300 per year. Other system components are inspected annually.

Step 3: Estimate the savings of a plunger lift. The savings associated with a plunger lift include:

- ★ Revenue from increased production;
- ★ Revenue from avoided emissions;
- ★ Additional avoided costs—well treatment costs, reduced electricity costs, workover costs; and
- ★ Salvage value.

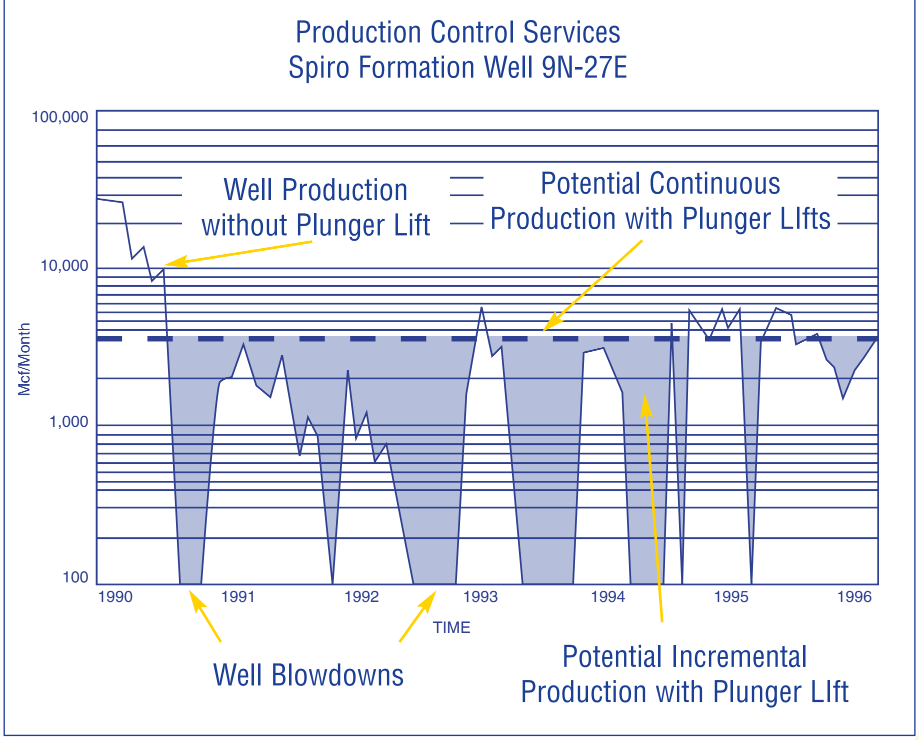
Revenue from Increased Production

The most significant benefit of plunger lift installations is the resulting increase in gas production. During the decision process, the increase in production cannot be measured directly and must be estimated. The methodology for estimating this expected incremental production varies depending on the state of the well. The methodology for continuous or non-declining wells is relatively straightforward. In contrast, the methodology for estimating the incremental production for wells in decline is more complex.

- ★ **Estimating incremental gas production for non-declining wells.** The incremental gas production from a plunger lift installation may be estimated by assuming that the average peak production rate achieved after blowdown is near the potential peak production rate for the well with fluid removed. A well log, like that illustrated in Exhibit 3, can be used to estimate the potential production increase.

In this exhibit, the solid line shows well production rate gradually, then steeply declining as liquids accumulate in the tubing. Production is restored by venting the well to the atmosphere, but then declines again with reaccumulation of liquids. Note that the production rate scale, in thousands of cubic feet per month, is a log scale. The dashed line shows the average peak production rate after liquids unloading. This is assumed to be equal to the potential peak production rate that could be achieved with a plunger lift system, typically at least 80 percent of the peak production rate after blowdown. The shaded area between the potential production (dashed-line) and the actual well production (solid-line) represents the estimate of incremental increase in gas production that can be achieved with a plunger lift system.

Exhibit 3: Incremental Production for Non-Declining Wells



★ **Estimating incremental production for declining wells or for situations in which the maximum production level after blowdown is not known.** Wells that are in decline or operated without periodic blowdowns require more detailed methods for estimating incremental production under plunger lift systems. Plunger lift installations on declining wells, for example, will require generating an improved declining curve resulting from decreased pressure at perforations. Operators should seek the assistance of a reservoir engineer to aid in these determinations (see Appendix).

Once incremental production from a plunger lift installation is estimated, operators can calculate the value of incremental gas and estimate the economics of the plunger lift installation. Exhibit 4 presents an example of potential financial returns at different levels of increase in gas production. It is important to recognize that local costs and conditions may vary. Note also that the example in Exhibit 4 does not take into account other financial benefits of a plunger lift installation project, such as avoided emissions and decreased electricity and chemical treatment costs, which are described later in this Lessons Learned. Consideration of these additional benefits may improve the already excellent financial returns of a plunger lift installation.

Exhibit 4: Example of Estimated Financial Returns for Various Levels of Incremental Gas Production from a Plunger Installation		
Incremental Gas Production (Mcfd)	**Payout Time (Months)**	**Internal Rate of Return (%)**
3	14	71
5	8	141
10	4	309
15	3	475
20	2	640
25	2	804
30	2	969

Assumptions:
Value of gas $7.00/Mcf.
Plunger system cost of $7,772 including start-up cost.
Lease operating expense of $790/year.
Production decline of 6%/year.

Source: Production Control Services, Inc.

Revenue from Avoided Emissions

The amount of natural gas emissions reduced following plunger lift installation will vary greatly from well to well, based on the individual well and reservoir characteristics such as sales line pressure, well shut-in pressure, liquids accumulation rate, and well dimensions (depth, casing diameter, tubing diameter). The most important variable, however, is the normal operating practice of venting wells. Some operators put wells on automatic vent timers, while others manually vent the wells with the operator standing by monitoring the vent, and still others open the well vent and leave, returning in hours or up to days, depending on how long it typically takes the well to clear liquids. Thus, the economic benefits from avoided emissions will also vary considerably. Such wide variability means that some projects will have much shorter payback periods than others. While most plunger lift installations will be justified by increased gas production rates alone, methane emissions reductions can provide an additional revenue stream.

★ **Avoided emissions when replacing blowdowns.** In wells where plunger lift systems are installed, emissions from blowing down the well can be reduced. Blowdown emissions vary widely in both their frequency and flow rates and are entirely well and reservoir specific. Emissions attributable to blowdown activities have been reported from 1 Mcf per year to thousands of Mcf per year per well. Therefore, the savings attributable to avoided emissions will vary greatly based on the data for the particular well being rehauled.

Revenue from avoided emissions can be calculated by multiplying the market value of the gas by the volume of avoided emissions. If the emissions per well per blowdown have not been measured, they must be estimated. In the example below, the amount of gas that is vented from a low pressure gas well at each blowdown is estimated as 0.5625 times the sustained flow gas rate. This emission factor assumes that the integrated average flow over the blowdown period is 56.25 percent of full well flow. Using this assumption, Exhibit 6 demonstrates that for an unloaded well producing 100 Mcf per day, the gas vented to the atmosphere can be estimated at 2 Mcf per hour of blowdown.

Exhibit 5: Example: Estimate Avoided Emissions from Blowdowns

Avoided Emissions per Hour of Blowdown	= (0.5625[1] × Sustained Daily Flow Rate) / 24 hrs/day
Avoided Emissions[2]	= (0.5625 × 100 Mcfd) / 24
	= 2 Mcf per hour of blowdown
Annual Value of Avoided Emissions[3]	= 2 Mcf × 12 × $7.00/Mcf
	= $168 per year

[1] Recommended methane emission factor reported in the joint GRI/EPA study, Methane Emissions From the Natural Gas Industry, Volume 7: Blow and Purge Activities (June 1995). The study estimated that at the beginning of a blowdown event, gas flow is restricted by fluids in the well to 25 percent of full flow. By the end of the blowdown event, gas flow is returned to 100 percent. The integrated average flow over the blowdown period is 56.25 percent of full well flow.

[2] Assuming a sustained daily production rate of 100 Mcfd.

[3] Assuming 1 blowdown per month lasting 1 hour.

This method is simple to use, but anecdotal evidence suggests that it produces estimates of methane emissions avoided that are unrealistically low. For an alternate method for estimating avoided emissions from blowdowns, see the Appendix.

Given the high degree of variability in emissions based on well and reservoir specific characteristics, measurement is the preferred method for determining avoided emissions. Field measurements can provide the data necessary to accurately determine the savings attributable to avoided emissions.

★ **Avoided emissions when replacing beam lifts.** In cases where plunger lifts replace beam lifts rather than blow downs, emissions will be avoided due to reduced workovers for mechanical repairs, to remove debris and cleanout perforations, to remove mineral scale and paraffin deposits from the sucker rods. The average emissions associated with workovers have been reported as approximately 2 Mcf per workover; the frequency of workovers has been reported to range from 1 to 15 per year. Due to well-specific characteristics such as flow during workover, duration of workover, and frequency of workover, avoided emissions can vary greatly.

Avoided Costs and Additional Benefits

Avoided costs depend on the type of liquid removal systems currently in place, but can include avoided well treatment, reduced electricity costs, and reduced workover costs. Avoided well treatment costs are applicable when plunger lifts replace beam lifts or other remedial techniques such as blowdown, swabbing, or soaping. Reduced electricity costs, reduced workovers, and recovered salvage value are only applicable if plunger lifts replace beam lifts.

- ★ **Avoided well treatment costs.** Well treatment costs include chemical treatments, microbial cleanups, and removal of rods and scraping the borehole. Information from shallow 1,500-foot wells show well remediation costs including rod removal and tubing rehabilitation at more than $14,500 per well. Chemical treatment costs (inhibitors, solvents, dispersants, hot fluids, crystal modifiers, and surfactants) are reported in the literature at a minimum of $13,200 per well per year. Microbial costs to reduce paraffin have been shown to be $6,600 per well per year (note that microbial treatments do not address the fluids influx problem). Each of these treatment costs increases as the severity of the scale or paraffin increases, and as the depth of the well increases.
- ★ **Reduced electricity costs compared to beam lifts.** Reduced electric operating costs further increase the economic return of plunger lifts. No electrical costs are associated with plunger lifts, because most controllers are solar-powered with battery backup. Exhibit 6 presents a range of avoided electricity costs reported by operators who have installed plunger lifts. Assuming 365 days of operation, avoided electricity costs range from $1,000 to $7,300 per year.

Exhibit 6: Electricity Costs[1] Avoided by Using a Plunger Lift in Place of a Beam Lift

Motor Size (BHP)	Operation Cost ($/day)
10	3
20	7
30	10
40	13
50	17
60	20

[1] Electricity cost assumes 50 percent of full load, running 50 percent of the time, with cost of 7.5 cents/kWh.

★ **Reduced workover costs compared to beam lifts.** Workover costs associated with beam lifts have been reported as $1,300 per day. While typical workovers may take one day, wells more than 8,000 feet deep will require more than one day of workover time. Depending on the well, from 1 to 15 workovers can be required per year. These costs are avoided by using a plunger lift.

★ **Recovered salvage value when replacing a beam lift.** If the plunger being installed is replacing a beam lift, extra income and a better economic return are realized from the salvage value of the old production hardware. Exhibit 7 shows the salvage value that may be obtained by selling the surplus pumping units. In some cases, salvage sales alone may pay for the installation of plunger lifts.

Exhibit 7: Salvage Value[1] of Legacy Equipment When Converting from Beam Lift to Plunger Lift Operations

Capital Savings from Salvaging Equipment	
Size of Pumping Unit (inch-lbs torque)	**Equipment Salvage Value ($)**
114,000	12,300
160,000	16,800
228,000	21,300
320,000	27,200
456,000	34,300
640,000	41,500

[1] Salvage costs include low estimate sale value of pumping unit, electric motor, and rod string.

Step 4: Evaluate the plunger lifts economics. A basic cash flow analysis can be used to compare the costs and benefits of a plunger lift with other liquid removal options. Exhibit 8 shows a summary of the costs associated with each option.

Exhibit 8: Cost Comparison of Plunger Lift vs. Other Options

Cost Category	Plunger Lift	Traditional Beam Lift	Remedial Treatment[1]
Capital and Startup Costs	$1,943–$7,772	$25,907- $51,813	$0
Implementation Costs:			
Maintenance[2]	$1,300/yr	$1,300–$19,500/yr	$0
Well Treatment[3]	$0	$13,200+	$13,200+
Electrical[4]	$0	$1,000–$7,300/yr	$0
Salvage	$0	($12,000–$41,500)	$0

[1] Includes soaping, swabbing, and blowing down.
[2] For traditional beam lift maintenance costs include workovers and assume 1 to 15 workovers per year at $1,300 per workover.
[3] Costs may vary depending on the nature of the liquid.
[4] Electricity costs for plunger lift assume the lift is solar and well powered.

★ **Economics of Replacing a Beam Lift with a Plunger Lift**

In Exhibit 9 the data from Exhibit 8 is used to model a hypothetical 100 Mcfd well and to evaluate the economics of plunger lift installation. The increase in production is 20 Mcf per day, yielding an annual increase in production of 7,300 Mcf. Assuming one workover per year prior to installation, the switch to a plunger lift also provides 2 Mcf of avoided emissions per year. The project profits greatly from the salvage value of the surplus beam lift equipment, yielding an immediate payback. Even if the salvage value is not recovered, the project may yield payback after only a few months depending on the well's productivity.

Exhibit 9: Economic Analysis of Plunger Lift Replacing a Beam Lift

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Value of Gas from Increased Production and Avoided Emissions[1]		$51,114	$51,114	$51,114	$51,114	$51,114
Plunger Lift Equipment and Setup Cost	($7,772)					
Plunger Lift Maintenance		($1,300)	($1,300)	($1,300)	($1,300)	($1,300)
Electric Cost per Year	$0	$0	$0	$0	$0	$0
Salvage Value Beam Lift Equipment	$21,300					
Avoided Beam Lift Maintenance (1 workover/yr)		$1,300	$1,300	$1,300	$1,300	$1,300
Avoided Beam Lift Electricity Costs (10HP motor)		$1,000	$1,000	$1,000	$1,000	$1,000
Avoided Chemical Treatments		$13,200	$13,200	$13,200	$13,200	$13,200
Net Cash Inflow	$13,528	$65,314	$65,314	$65,314	$65,314	$65,314

NPV (Net Present Value)[2] = $261,119
Payback Period = Immediate

[1] Gas valued at $7.00 per Mcf for 7,300 Mcf due to increased production and 2 Mcf from avoided emissions per event (based on 1 workover per year).
[2] Net present value based on 10 percent discount rate over 5 years.

★ **Economics of Avoiding Blowdown with a Plunger Lift**

Exhibit 10 uses data from Exhibit 8 to evaluate the economics of a hypothetical 100 Mcfd well at which a plunger lift is installed to replace blowdown as the method for removing liquid from the well. Assuming the increased production is 20 Mcf per day, the annual increase in production is 7,300 Mcf. In addition, there will be savings from avoided emissions during blowdown. Assuming 12 one-hour blowdowns per year, the avoided emissions are 24 Mcf per year.

Exhibit 10: Economic Analysis of Plunger Lift Replacing Blowdown

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Value of Gas from Increased Production and Avoided Emissions[1]		$51,268	$51,268	$51,268	$51,268	$51,268
Plunger Lift Equipment and Setup Cost	($7,772)					
Plunger Lift Maintenance		($1,300)	($1,300)	($1,300)	($1,300)	($1,300)
Electric Cost per Year	$0	$0	$0	$0	$0	$0
Avoided Chemical Treatments		$13,200	$13,200	$13,200	$13,200	$13,200
Net Cash Inflow	($7,772)	$63,168	$63,168	$63,168	$63,168	$63,168

NPV (Net Present Value)[2] = $231,684
Payback Period = 2 months

[1] Gas valued at $7.00 per Mcf for 7,300 Mcf due to increased production and 24 Mcf from avoided emissions per event (based on 12 blowdowns per year and 2 Mcf per blowdown).
[2] Net present value based on 10 percent discount rate over 5 years.

When assessing options for installing plunger lift systems on gas wells, natural gas price may influence the decision making process. Exhibit 11 shows an economic analysis of installing a plunger lift system rather than blowing down a well to the atmosphere to lift accumulated fluid at different natural gas prices.

Exhibit 11: Gas Price Impact on Economic Analysis

	$3/Mcf	$5/Mcf	$7/Mcf	$8/Mcf	$10/Mcf
Value of Gas Saved	$21,972	$36,620	$51,268	$358,592	$73,240
Payback Period (Months)	3	2	2	2	2
Internal Rate of Return (IRR)	436%	624%	813%	907%	1095%
Net Present Value (i=10%)	$120,630	$176,157	$231,684	$259,448	$314,976

Case Studies

BP (formerly Amoco) Midland Farm Field

Amoco Corporation, a Natural Gas STAR charter partner (now merged with BP), documented its success in replacing beam lift, rod pump well production equipment with plunger lifts at its Midland Farm field. Prior to installing plunger lift systems, Amoco used beam lift installations with fiberglass rod strings. The lift equipment was primarily 640 inch-lb pumping units powered by 60 HP motors. Operations personnel noted that wells at the field were having problems with paraffin plating the well bore and sucker rods, which blocked fluid flow and interfered with fiberglass sucker rod movement. Plunger lifts were seen as a possible solution to inhibit the accumulation of paraffin downhole.

Amoco began its plunger lift replacement program with a single-well pilot project. Based on the success of this initial effort, Amoco then expanded the replacement process to the entire field. As a result of the success in the Midland Farm field, Amoco installed 190 plunger lift units at its Denver City and Sundown, Texas locations, replacing other beam lift applications.

Costs and Benefits

Amoco estimated that plunger lift system installation costs-including plunger equipment and tubing conversion costs-averaged $13,000 per well (initial pilot costs were higher than average during the learning phase, and the cost of tubing conversion is included).

Amoco then calculated savings resulting from avoided costs in three areas-electricity, workover, and chemical treatment. Overall, Amoco estimated that the avoided costs of electricity, workover, and paraffin control averaged $24,000 per well per year.

★ **Electricity.** Cost savings were estimated based on 50 percent run times. Using the costs from Exhibit 6, the estimated electrical cost savings were estimated to be $20 per day.

★ **Workover**. On average, Amoco had one workover per year per well to fix rod parts. With the old beam lift systems, the cost of this operation was $4,000, averaging about $11 per day.

★ **Chemical treatment.** The biggest savings were realized from avoided chemical treatment. Amoco was able to save the approximately $13,000 per well per year for paraffin control because the plunger operation removed paraffin accumulation in the tubing.

Increased Gas Production and Revenue

For the initial plunger lift installation, Amoco realized an increase in gas production of more than 400 Mcf per day. Upon expansion of the plunger lift installation to the entire field, the company realized notable success in many wells—although some showed little or no production increase during the 30 day evaluation period. Total production increase (including both incremental production and non-emitted gas) across all wells where plunger lifts were installed was 1,348 Mcf per day. The average annual gas savings, which assumes a 6 percent production decline, was 11,274 Mcf per well or approximately $78,918 per well at 2006 prices. Exhibit 12 and Exhibit 13 summarize the initial results and first year economics of Amoco's Midland Farm plunger lift installation. In addition to the gas savings and cost savings from the plunger lift installations, Amoco realized a one-time gain from the sale of surplus pumping units and motors, resulting in additional revenue of $41,500 per installation.

Exhibit 12: Change in Production Rates due to Plunger Lift Installation in Midland Farm Field, Texas

[1]Well #	Production Before Plunger Lift			Production 30 Days After Installation		
	Gas (Mcfd)	Oil (Bpd)	Water (Bpd)	Gas (Mcfd)	Oil (Bpd)	Water (Bpd)
1	233	6	1	676	5	1
2	280	15	1	345	15	1
3	240	13	2	531	33	11
4	180	12	2	180	16	3
5	250	5	2	500	5	2
6	95	8	2	75	12	0
7	125	13	1	125	14	0
8	55	6	1	55	13	2
9	120	45	6	175	40	0
10	160	16	3	334	17	3
11	180	7	12	80	6	6
12	215	15	4	388	21	2
13	122	8	8	124	12	7
14	88	5	10	23	9	1
Avg.	167	12	4	258	16	3

[1] All wells approximately 11,400 feet deep.
Source: World Oil, November, 1995

Analysis

A summary of the costs and benefits associated with Amoco's plunger lift installation program is provided below in Exhibit 13. For the first year of operation, the company realized an average annual savings of approximately $90,200 per well at 2006 prices. In addition the company realized approximately $41,500 per well from salvage of the beam lift equipment at 2006 costs.

Exhibit 13: BP Economics of Plunger Lifts Replacing Beam Lifts							
Average Annual Gas Savings[1] (Mcf/ Year)	Value of Gas Saved per Year[2]	Plunger Lift Installation Cost per Well	Avoided Rod Workover Cost per Well per Year	Avoided Chemical Treatment per Well per Year	Avoided Electrical Costs per Well per Day	Average Savings per Well[3]	Additional Salvage Value of Beam Lift per Well
11,274	$78,918	$13,000	$4,000	$13,000	$20	$90,200	$41,500

[1] Average initial gas production = 1,348 Mcfd. Assumes 6 percent annual production decline.
[2] Gas valued at $7.00 per Mcf.
[3] Value saved is averaged over 14 wells.

ExxonMobil Big Piney Field

At Big Piney Field in Wyoming, Natural Gas STAR charter partner Mobil Oil Corporation (now merged with Exxon) has installed plunger lift systems at 19 wells. The first two plunger lifts were installed in 1995, and the remaining wells were equipped in 1997. As a result of these installations, Mobil reduced overall blowdown gas emissions by 12,166 Mcf per year. In addition to the methane emission reduction, the plunger lift system reduced the venting of ethane (6 percent by volume), C3 hydrocarbons + VOCs (5 percent), and inerts (2 percent). Exhibit 14 shows the emission reductions for each well after plunger lift installation.

Exhibit 14: Plunger Lift Program at Big Piney, Wyoming			
Well #	Pre-Plunger Emission Volume (Mcf/yr/well)	Post-Plunger Emission Volume (Mcf/yr/well)	Annualized Reduction (Mcf/yr/well)
1	1,456	0	1,456
2	581	0	581
3	1,959	318	1,641
4	924	0	924
5	105	24	81
6	263	95	168
7	713	80	633
8	453	0	753
9	333	0	333
10	765	217	548
11	1,442	129	1,313
12	1,175	991	184
13	694	215	479
14	1,416	1,259	157
15	1,132	708	424
16	1,940	561	1,379
17	731	461	270
18	246	0	246
19	594	0	594
Totals	**17,224**	**5,058**	**12,166**

Installation Tips

The following suggestions can help ensure trouble-free installation of a plunger lift system:

★ **Do not use a completion packer, because it limits the amount of gas production per plunger trip.** Without a completion packer, the entire annular void space is available to create a large compressed gas supply. The greater the volume of gas, the larger the volume of water that can be lifted.

★ **Check for tubing obstructions with a gauge ring before installation.** Tubing obstructions hinder plunger movement and may require replacement of production tubing.

★ **Capture the plunger after the first trip.** Inspection of the plunger for the presence of any damage, sand, or scale will help prevent any subsequent plunger lift operational difficulties, permitting immediate operational repair while the crew and installation equipment are mobilized.

Lessons Learned

Plunger lift systems offer several advantages over other remedial treatments for removing reservoir fluids from wells: increased gas sales, increased well life, decreased well maintenance, and decreased methane emissions. The following should be considered when installing a plunger lift system:

- ★ Plunger lift installations can offer quick paybacks and high return on investments whether replacing a beam lift or blowdowns.
- ★ Plunger lift installations can greatly reduce the amount of remedial work needed throughout the lifetime of the well and the amount of methane vented to the atmosphere.
- ★ An economic analysis of plunger lift installation should include the incremental boost in productivity as well as the associated extension in well life.
- ★ Even when the well pressure declines below that necessary to lift the plunger and liquids against sales line back pressure, a plunger is more efficient in removing liquids with the well vented to the atmosphere than simply blowing the well without a plunger lift.
- ★ Include methane emission reductions from installing plunger lift systems in annual reports submitted as part of the Natural Gas STAR Program.

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Appendix

Estimating incremental production for declining wells.

From Dake's *Fundamentals of Reservoir Engineering* (1982) we can use the following equation to calculate the increase in downhole flow for reduced pressure that may be seen when using a plunger lift. A semi-steady state inflow equation can be expressed as:

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

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

After the reservoir parameters are gathered, this equation can be solved for Q for the retarded flow with fluids in the hole (current conditions and current decline curve), and Q for no fluids in the hole (plunger lift active and improved decline curve). This is a guideline, and operators are reminded to use a reservoir engineer to aid in this determination.

Alternate technique for calculating avoided emissions when replacing blowdowns.

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

Annual Vent Volume, Mscf/yr = $(0.37\times10^{-6}) \times (\text{Casing Diameter})^2 \times$ Well Depth $\times$ Shut-in Pressure $\times$ Annual Vents

Where casing diameter is in inches, well depth is in feet and shut-in pressure is in psig. Exhibit A1 shows an example calculation.

Exhibit A1: Example: Estimate Avoided Emissions from Blowdowns	
Casing Diameter	8 inches
Well Depth	10,000 feet
Shut-in Pressure	214.7 psig
Annual Vents	52 (weekly venting)
Annual Vent Volume = $(0.37\times10^{-6}) \times 8^2 \times 10{,}000 \times 214.7 \times 52 = 2{,}644$ Mscf/yr	

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 in Exhibit 2, 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 zero psig. Partners can estimate the minimum time 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 the partner's practice and experience is to vent the wells a longer time than calculated by these methods, the conservative Annual Vent Volume can be increased by a simple ratio of the actual vent times and the minimum vent time calculated using the Weymouth equation.

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