EPA
United States
Environmental Protection
Agency

Air and Radiation
(6202J)

EPA430-B-01-004
July 2001

LESSONS LEARNED

FROM NATURAL GAS STAR PARTNERS

NaturalGas
EPA POLLUTION PREVENTER

INSTALLING PLUNGER LIFT SYSTEMS IN GAS WELLS

Executive Summary

In mature gas wells, the accumulation of fluids in the wellbore can impede and, in some cases, halt production. To keep gas flowing, accumulated fluids are commonly removed 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). As a result of these remedial operations, large volumes of methane are emitted into the atmosphere.

Installing a plunger lift system is a cost-effective alternative for removing liquids, and has the additional benefit of increasing production and significantly reducing methane emissions associated with blowdown and other remedial operations. A plunger lift uses the well's remaining productive energy to lift the immobile fluid column out of the well. By removing gas well liquids, the plunger lift system helps to maintain production levels and eliminates the need for traditional remedial treatments.

Natural Gas STAR partners have reported 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 $54,750. Benefits from both increased gas production and emissions savings are well- and reservoir-specific and will vary considerably.

Action	Volume of Gas From Emissions Savings and Avoided Emissions (Mcf/year)	Value of Saved Gas[1] ($)	Average Cost of Implementation ($/well)	Payback
Install a plunger lift system	4,695 - 18,250[2]	$14,085 - $54,750	$5,000	< 6 months

[1] Value of gas $3.00/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). The installation of plunger lift systems in gas wells often yields significant reductions in gas emissions and can extend well life.

LESSONS LEARNED
FROM NATURAL GAS STAR PARTNERS

NaturalGas
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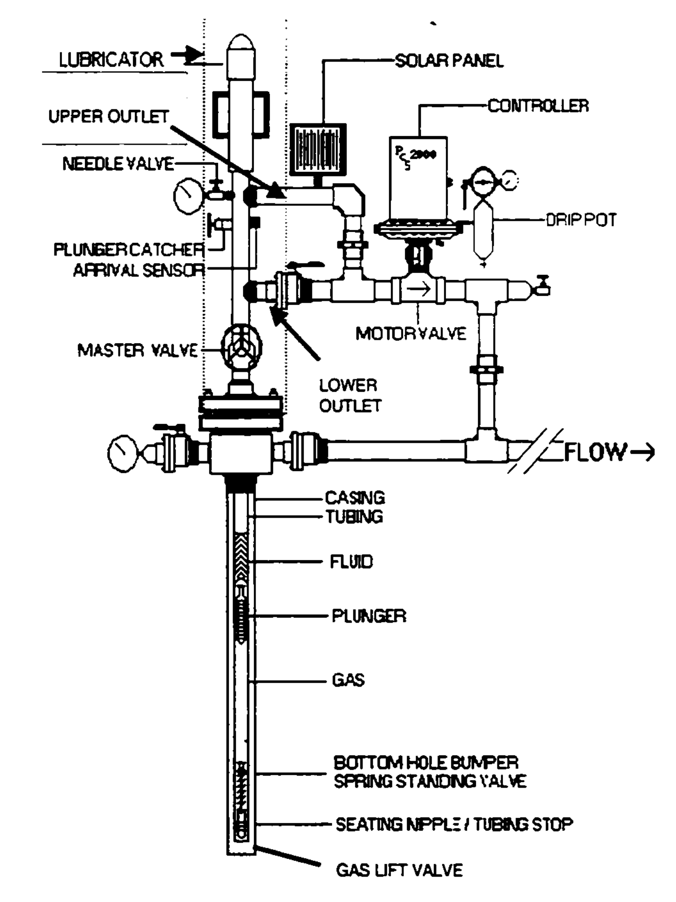
INSTALLING PLUNGER LIFT SYSTEMS IN GAS WELLS

Technology Background

Liquid loading of the wellbore is often a serious problem in aging production wells. Operators commonly use beam lifts 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 re-accumulate, resulting in additional methane emissions.

Plunger lift systems are a cost-effective alternative to 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 a swab or steel plunger to lift fluids up the well tubing to the surface. The plunger serves as both an interface between the liquid and gas to minimize liquid fallback and as a scale and paraffin scraper. Exhibit 1 depicts a typical plunger lift system.

Exhibit 1: Plunger Lift Schematic



Source: Production Control Services

The operation of a plunger lift system relies on the natural buildup of pressure during the shut-in of a wellbore. The gas pressure is used to force 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. In general, the operation of a typical plunger lift involves the following steps:

1. The plunger begins near the bottom of the well on the bottom hole bumper spring.
2. Annulus gas pressure opens a downhole gas lift valve and creates the differential pressure necessary to lift the plunger and liquid load to the surface.
3. Gas and produced liquids flow through the upper outlet in the plunger lift lubricator.
4. The gas lift valve closes downhole.
5. The plunger arrives in the lubricator and partially seals off the lower lubricator outlet.
6. Gas that has lifted the plunger is produced through the lower lubricator outlet.
7. As gas is produced, the lifting force on the plunger is released and the plunger drops downhole to the bumper spring.
8. The cycle repeats.

Economic and Environmental Benefits

The installation of a plunger lift system serves as a cost-effective alternative to beam lifts and well blowdowns that yields significant economic and environmental benefits. The extent and nature of these benefits depends 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 significantly less than the cost of beam lift equipment. Costs do not increase with depth, provided production tubing is part of the original well completion.

☆ **Lower well maintenance versus repetitive remedial treatments.** Overall maintenance is reduced because repetitive remedial treatments such as swabbing or well blowdowns become unnecessary with the continuous operation of the plunger lift.

☆ **Continuous production-improving gas rates and efficiency.** Plunger lift systems can conserve the well's lifting energy and increase gas production. By replacing well blowdowns, ongoing fluid removal permits the well to produce gas continuously and avoid periods of halted gas production. In some cases, the continuous removal of fluids yields higher daily gas production rates, often above the previous decline curve.

☆ **Reduced paraffin and scale buildup.** In wells where paraffin or scale buildup is a problem, the motion of the plunger may prevent particulate buildup inside the tubing. Thus, the need for chemical or swabbing treatments may be reduced or eliminated. This is advantageous when the plunger lift is replacing a beam lift system as well as well blowdowns.

☆ **Lower methane emissions.** Eliminating repetitive remedial treatments and well workovers also reduces methane emissions. Gas STAR partners have reported annual gas savings averaging 600 thousand cubic feet (Mcf) per well by avoiding blowdowns 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 workover costs. Moreover, wells that move water continuously out of the wellbore have the potential to produce more condensate and oil.

Decision Process

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

Decision Process for Evaluating Installation of Plunger Lift Systems:

1. ***Determine the technical feasibility of a plunger lift installation.***
2. ***Determine the cost of a plunger lift.***
3. ***Estimate the savings achieved by plunger lift installation.***
4. ***Compare the overall costs and benefits of plunger lifts vs. other techniques.***

Step 1: Determine the technical feasibility of a plunger lift installation. Plunger lifts are applicable in wells that have sufficient gas volume and gas pressure to move liquids with some assistance. Exhibit 2 lists four common situations in which plunger lifts are appropriate at a well. Vendors can supply written materials designed to help well operators ascertain whether a particular well would benefit from the installation of a plunger lift system.

Exhibit 2: Common Plunger Lift Applications

☆ Wells in which atmospheric blowdowns are necessary to restore production.

☆ Wells with a gas-to-liquid ratio of 400 scf/bbl per 1,000 feet of depth or greater.

☆ 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 installing and operating a plunger lift. Costs associated with plunger lifts include capital and labor expenditures to purchase and install the equipment, as well as ongoing costs to operate and maintain the system. These costs include:

☆ **Capital costs.** A typical plunger lift system costs approximately $1,500 to $6,000. In contrast, installation of surface pumping equipment, such as a beam lift, costs between $20,000 and $40,000. Operators considering installing a plunger lift should note that the system requires a continuous tubing string with a constant internal diameter in good condition. The replacement of the tubing string, if required, can considerably add to the cost of installation.

☆ **Operating costs.** Plunger lift maintenance requires routine inspection of the lubricator spring and plunger. Typically, these items need to be replaced every 6 to 12 months, at an approximate cost of $500 to $1,000 per year. Other system components are inspected annually.

Step 3: Estimate the savings achieved by plunger lift installation. The savings associated with a plunger lift include:

- ☆ Revenue from avoided emissions;
- ☆ Revenue from increased production;
- ☆ Avoided well treatment costs when plunger lifts replace beam lifts or other techniques such as blowdown, swabbing, or soaping; and
- ☆ Recovered salvage value, reduced electricity costs, and reduced workover costs when replacing a beam lift.

Revenue from Increased Production

One of the most significant benefits of plunger lift installations is the resulting increase in gas production. During the decision making 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 straight forward. In contrast, the methodology for estimating the incremental production for wells in decline or wells where periodic blowdown data is not collected, is more complex.

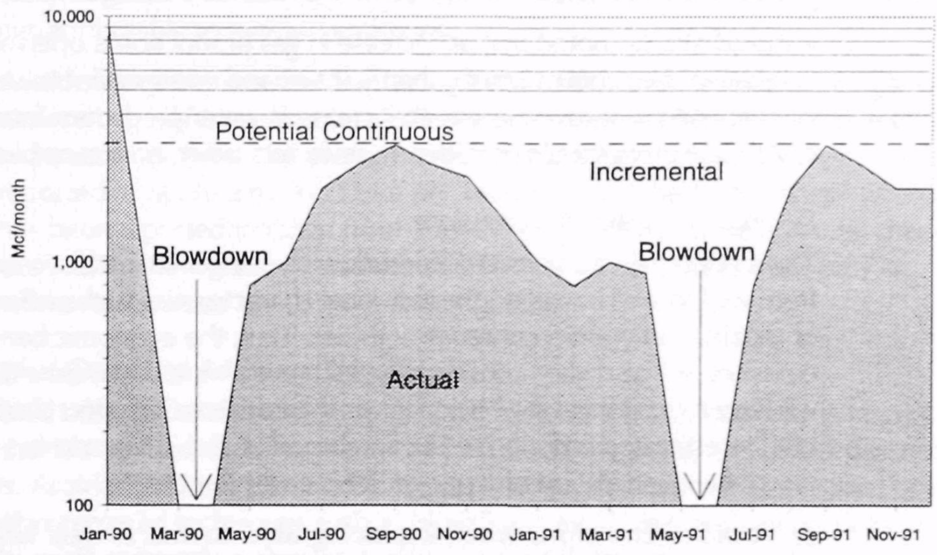
- ☆ **Estimating incremental gas production for non-declining wells.** For wells that are not in decline (i.e., wells that maintain relatively constant flow rates when clear of fluid accumulation), incremental gas production may be estimated by assuming that the highest level of production achieved after blowdown is what the continuous production rate would be if plunger lift systems were installed. Incremental production is the difference between average current production and potential continuous production, a calculation illustrated and described in Exhibit 3.

Exhibit 3: Estimating Incremental Production for Non-Declining Wells

1. Estimate the level of production under continuous production by taking the maximum level of production achieved after each blowdown and multiplying by the number of months in the period being examined.
2. Sum the actual production of all months in the period being examined.
3. Subtract the result of step 2 from the result of step 1.

Exhibit 4 depicts a theoretical production curve for a non-declining well, interrupted by periods of fluid accumulation. These are times when gas would have been produced using a plunger lift system. The exhibit shows the rapid resumption of production after fluid accumulations have been cleared by blowdowns. The maximum production rate after blowdown is assumed to be equal to the potential continuous production rate using a plunger lift system. The white area below the potential continuous line is the incremental gas production resulting from using plunger lift systems.

Exhibit 4: 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 decline curve resulting from decreased pressure at perforations. Operators should use a reservoir engineer and appropriate resources such as Dake's *Fundamentals of Reservoir Engineering* (1982) to aid in these determinations (see Appendix).

Once the volume of incremental production has been estimated, operators can convert this volume into a dollar value or an associated return on investment. Exhibit 5 presents the resulting financial returns at different increases in production levels. It is important to

Exhibit 5: Financial Returns at Varying Levels of Gas Sales Increases

Gas Sales Increase (Mcfd)	Payout Time (months)	Internal Rate of Return (%)	Return on Investment (%)
3	28	38	350
5	16	69	580
10	8	144	1,150
15	5	219	1,730
20	4	294	2,310
25	3	369	2,880
30	3	444	3,460

Assumptions:
Value of Gas $3.00/Mcf
Plunger system cost of $6,000
Lease operating expense of $600/mo
Production decline of 6%/yr
Discount rate of 15%

Source: Production Control Services, Inc.

recognize that local costs and conditions may vary. In addition, in some cases, it is possible that an increase in gas production may not be realized, or the well will continue to decline. Engineers are advised to use this exhibit only as a guideline.

It should also be noted that an increase in gas production is often accompanied by an increase in the production of other fluids-oil and water. An increase in oil production can provide more revenue, but an increase in water production increases disposal costs. Operators should consider these factors when evaluating plunger lift installations.

Revenue from Avoided Emissions

The amount of emissions reduced following plunger lift installation will vary greatly from well to well based on the individual characteristics such as flow rate, frequency of repairs, and duration of repair activities. Thus, the economic benefits from avoided emissions will also vary considerably. Such wide variability means that some projects will have much longer payback periods than others. Operators should carefully calculate the estimated emissions reduction based on the characteristics of each well to determine if installation of a plunger lift is cost-effective.

☆ **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 gas flow 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 6: Estimating Avoided Emissions from Blowdowns

Avoided Emissions per Hour of Blowdown	= (0.5625[1] x Sustained Daily Flow Rate) ÷ 24 hrs/day
Avoided Emissions[2]	= (0.5625 x 100 Mcfd) ÷ 24 = 2 Mcf per hour of blowdown
Annual Value of Avoided Emissions[3]	= 2 Mcf x 12 x $3.00/Mcf = $72 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.

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 blowdowns, emissions will be avoided due to reduced workovers. The average emissions associated with workovers have been reported as approximately 2 Mcf per workover and 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 workovers 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 $11,000 per well. Chemical treatment costs (inhibitors, solvents, dispersants, hot fluids, crystal modifiers, and surfactants) are reported in the literature at a minimum of $10,000 per well per year. Microbial costs to reduce paraffin have been shown to be $5,000 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 increase, 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. There are no electrical costs with plunger lifts because most controllers are solar-powered with battery backup. Exhibit 7 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 7: 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 $1,000 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 8 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 8: 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	9,500
160,000	13,000
228,000	16,500
320,000	21,000
456,000	26,500
640,000	32,000

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

Step 4: Compare the overall costs and benefits of plunger lifts versus other techniques. A basic cash flow analysis can be used to compare the costs and benefits of a plunger lift with other liquid removal options. Exhibit 9 shows a summary of the costs associated with each option.

Exhibit 9: Cost Comparison of Plunger Lift vs. Other Options

Cost Category	Plunger Lift	Traditional Beam Lift	Remedial Treatment[1]
Capital Costs	$1,500 - $6,000	$20,000 - $40,000	$0
Implementation Costs			
Maintenance[2]	$1,000/yr	$1,000 - 15,000/yr	$0
Well Treatment[3]	$0	$10,000+	$10,000+
Electrical[4]	$0	$1,000 - $7,300/yr	$0
Salvage Value of Old Equipment	$0	($9,000 - $32,000)	$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 $1,000 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 10, the data from Exhibit 9 is used to model a hypothetical 100 Mcfd well and 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. If the salvage value is not recovered, the project may yield payback after only a few months depending on the well's productivity.

Exhibit 10: 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 (Mcf)[1]		$21,906	$21,906	$21,906	$21,906	$21,906
Plunger Lift Installation	($5,000)					
Plunger Lift Maintenance		($1,000)	($1,000)	($1,000)	($1,000)	($1,000)
Electric Cost per Year	$0	$0	$0	$0	$0	$0
Salvage Value Beam Lift Equipment	$16,500					
Avoided Beam Lift Maintenance (1 workover/yr)		$1,000	$1,000	$1,000	$1,000	$1,000
Avoided Beam Lift Electricity Costs (10HP motor)		$1,000	$1,000	$1,000	$1,000	$1,000
Avoided Chemical Treatments		$10,000	$10,000	$10,000	$10,000	$10,000
Net Cash Inflow	$11,500	$32,906	$32,906	$32,906	$32,906	$32,906

NPV (Net Present Value)[2] = $123,854
Payback Period[3] = Immediate

[1] Gas valued at $3.00 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.
[3] If the salvage value is not recovered, the payback period will vary from 1 to 6 months depending on well productivity.

Economics of Avoiding Blowdown with a Plunger Lift

Exhibit 11 uses data from Exhibit 9 to evaluate the economics of a hypothetical 100 Mcfd well where 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 11: Economic Analysis of Plunger Lift Replacing Blowdown						
	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Value of Gas From and Increased Production Avoided Emissions (Mcf)[1]		$21,972	$21,972	$21,972	$21,972	$21,972
Plunger Lift Installation	($5,000)					
Plunger Lift Maintenance.		($1,000)	($1,000)	($1,000)	($1,000)	($1,000)
Electric Cost per Year	$0	$0	$0	$0	$0	$0
Avoided Chemical Treatments		$10,000	$10,000	$10,000	$10,000	$10,000
Net Cash Inflow	($5,000)	$30,972	$30,972	$30,972	$30,972	$30,972

NPV (Net Present Value)[2] = $102,189
Payback Period = <6 months

[1] Gas valued at $3.00 per Mcf assuming 7,300 Mcf due to increased production and 24 Mcf in avoided emissions per event (based on 12 blowdowns per year).
[2] Net present value based on 10 percent discount rate over 5 years.

Case Studies

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 had been using beam lift installations with downhole 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 such as paraffin coming out of suspension and plating on 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. Later, as a result of the success in the Midland Farm field, Amoco installed 190 plunger lift units in its Denver City, Texas 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 approximately $10,000 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 $20,000 per well per year.

- ☆ **Electricity.** Cost savings were estimated based on 50 percent run times. Using the costs from Exhibit 7, the estimated electrical cost savings per day were estimated at $20.
- ☆ **Workover.** On average, Amoco had one rod workover per year per well to fix rod parts. With the old beam lift systems, the cost of this operation was $3,000, averaging about $8 per day.
- ☆ **Chemical Treatment.** The biggest savings were realized from avoided chemical treatment. Amoco was able to save the approximately $10,000 per well per year that had been necessary for paraffin control because the plunger operation prevented accumulation in the wellbore.

Increased Gas Production and Revenue

At the initial well at which a plunger lift was installed, Amoco realized an increase in gas production of over 400 Mcf per day. Upon expansion of the replacement process 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—with a value of $4,044 per day, or $33,822 per year - assuming a 6% straight line decline in production (see Exhibit 12 on next page).

In addition, Amoco gained additional revenue through the sale of surplus pumping units and motors, resulting in additional income of $32,000 per installation.

Analysis

A summary of the costs and benefits associated with Amoco's plunger lift installation program is provided below in Exhibit 13. Overall, the company realized an average savings per well of approximately $44,700.

Exhibit 13: Amoco Economics of Plunger Lifts Replacing Beam Lifts

Gas Volume Saved Per Day (Mcf)	Value of Gas Saved Per Year[1]	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	Salvage Value of Beam Lift Per Well	Average Savings Per Well[2]
1,348	$33,822	$10,000	$3,000	$10,000	$20	$32,000	$44,700

[1] Gas valued at $3.00 per Mcf.
[2] Value saved is averaged over 14 wells.

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.

Mobil 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 all of its 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 (see next page) presents 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	1,458	0	1,458
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	753	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 plunger lift system is free to use the entire annular void space to create a large gas cushion. A larger gas cushion will allow more gas to be produced when the gas pressure pushes the plunger to the surface.

☆ **Shut in the well the day before installation.** This allows the casing pressure to build up and may eliminate the need for swabbing to reduce the liquid weight on the plunger.

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

☆ **Position the tubing as close to the perforations as possible.** If the tubing is placed above or below the perforations, the gas cushion must act against what could be a significant hydrostatic pressure column. Proper tubing placement maximizes gas production.

☆ **Capture the plunger after the first trip.** Inspection of the plunger for the presence of any damage, sand, or scale will deter 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.

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Appendix

From Dake, *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.

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