Natural Gas Well Emission Reduction Demonstration Program

Final Report

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ABSTRACT

Keywords:

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Methane Reduction
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Plunger Lift
Tubing Plunger

ACKNOWLEDGMENT

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SUMMARY

The New York State Energy Research and Development Authority (NYSERDA) selected Advanced Resources International, Inc. as engineering support contractor for the NYSERDA/U.S. EPA Natural Gas Well Emission Reduction Demonstration Program. The goal of the program is to develop and demonstrate operating systems for independent producers that will increase overall well efficiency, improve well economics, and reduce the emission of methane into the environment. Advanced Resources' role in the project was to:

- Assist NYSERDA in the selection and contracting of four demonstration projects;
- Manage the demonstrations including arranging for equipment purchasing, installation, testing and monitoring;
- Conduct economic and environmental analyses of the demonstration projects;
- Complete case study reports.

Three of the four demonstration projects employed technologies related to well dewatering and the mitigation of methane emissions associated with swabbing and well blow-down operations. The fourth project entailed the installation of low-bleed controllers at two large compression facilities. Secondary goals of the program were to enlist projects that were geographically diverse (Figure 1) as well as representative of different types of producing formations. The four demonstration projects in the program are:

- Paxton Resources: Deep Gas Lift, Antrim shale, Michigan Basin
- Lenape Resources: Autocycle Controllers/Rabbit Tubing Plungers, Clinton-Medina sand, New York
- Union Pacific Resources/Anadarko Petroleum Corp.: Low Bleed Controllers, C.E. Moore and J.R. Kyle Compression Facilities, Texas
- Trinity Energy Corp.: Plunger Lift, D-J Sand, Denver-Julesburg Basin

The volumes of methane mitigated from any single demonstration project are relatively low, on the order of a few Mcf/day or less. However, the program could have a major impact on methane emissions from natural gas well systems given that over two-thirds of the wells drilled in the U.S. are by independent producers -- in New York State alone the volumes could be as much as 3 Bcf over 25 years.

Most importantly, however, from the perspective of the independent operators is that these technologies reduce operating costs and can improve well recoveries.

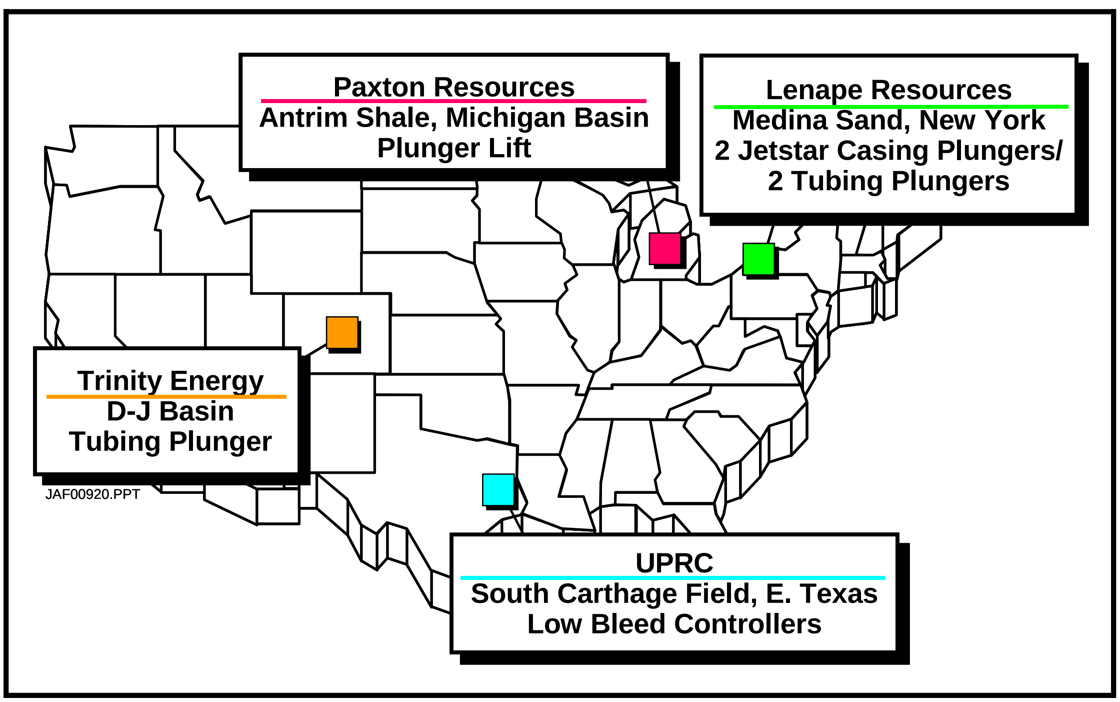

Figure 1
NYSERDA Demonstration Project Locations

PROJECT NUMBER 1

Company: PAXTON RESOURCES

Location: ANTRIM SHALE, MICHIGAN

Project: DEEP GAS LIFT/PLUNGER LIFT

COMPANY OVERVIEW

Formed in 1995 by Scott D. Lampert, President of Devonian Energy, Inc., and William J. Muzyl, President of Muzyl Oil Corporation, with the specific purpose to drill and operate Antrim Wells. The Company has grown significantly each year since its inception.

Paxton is primarily engaged in the acquisition of domestic oil and gas producing properties and development, production, and sale of natural gas, crude oil, and natural gas liquids from the 565 wells that it operates. Paxton is scheduled to drill 75 to 100 new wells per year for the next few years in a number of basins.

Paxton's current area of focus is geared toward development of the Antrim Shale in northern Michigan and exploration and development of its coalbed methane properties in the Powder River Basin of Wyoming.

Paxton is headquartered in Gaylord Michigan with offices in Lansing, Michigan and Sheridan, Wyoming.

OVERVIEW OF ANTRIM SHALE PRODUCTION IN NORTHERN MICHIGAN

While gas production was established from Michigan's Antrim Shale in the late 1930's from a handful of wells, development came much later. About 100 wells were drilled from the mid 1960's to the mid 1980's, but large-scale development did not begin until the late 1980's. With several hundred wells being drilled each year since, there have been over 6,000 wells drilled targeting the Antrim. The Antrim formation has produced over 1 Tcf in northern Michigan from approximately 395 multi well projects, and is currently producing about 18 Bcf per month.

With ever improving technology, the Antrim play is expanding into previously unproductive areas and the average production per well is increasing. Continued technological advancements promise a long life of economic production from the Antrim. A typical Antrim well will recover 820 MMcf.

The Antrim is Late Devonian black shale with unusually high quartz and organic content. It serves as both source and reservoir. While gas is found trapped within the Antrim throughout its extent in the Michigan Basin, economic production is limited to areas where the Antrim is highly fractured. Intense fracturing along the northern subcrop of the Antrim Shale provides excellent permeability in an otherwise unattractive reservoir rock. Gas is reservoired in the fractures, the microporosity of the matrix, and through adsorption to the matrix.

The Antrim Shale can be divided into 4 distinct zones: the Upper Antrim which consists of light gray to black shales of fairly low gamma ray readings on gamma ray logs, the Lachine which is black and exhibits high gamma ray readings, the Paxton which is gray with fairly low gamma ray readings, and the Norwood which is black and also exhibits high gamma ray readings.

Natural fractures are the key to the productive characteristics of the Antrim Shale. Regional geologic studies indicate that the shallower the Antrim is, the more highly fractured it is. This phenomenon is widely believed to have been caused by glacial scouring.

DESCRIPTION OF TECHNOLOGY IMPLEMENTED

Deep Gas Lift (DGL) is one of several techniques currently being used to produce water from a shallow Antrim shale well. These wells produce natural gas with associated CO2 and water that comes from natural and induced fracture networks in the shale. These fracture networks are what provide the passageways for all production to find its way to the wellbore. Once in the wellbore, the water and gases separate with the water dropping to the bottom of the wellbore where it is lifted up the tubing to surface while the gas rises up the annulus to surface. These wells produce varying amounts of water in conjunction with the natural gas and must be dewatered to reach their maximum production. Once the gas and water reach surface they are put into a gathering system of flowlines that goes to a central facility. The gas is then compressed for sales and the water is put down a disposal well. The DGL system was chosen as the preferred water production method with these criteria in mind: a system that has few moving parts, can move varying amounts of water, is corrosion resistant (CO2 and water from carbonic acid) and has low maintenance costs associated with its operation and repairs. The DGL system seemed like a natural fit and was implemented on all six wells in the Daddy Warbucks project located in Livingston Township, Otsego County, Michigan.

The components of the system include: a 2" high pressure gas lift line to the well, dual flowlines from the well to the central facility, a well with 400-500' of cased rat hole below the producing formation, 1.9" OD fiberglass tubing string, surface timer/controller, ¾" Stainless Steel (SS) side string, SS Side pocket injection mandrel, SS standing valve, and a plunger (when needed for more efficiency) (Figure 2 and Figure 3). The high pressure gas travels through the lift line to the wellhead where the surface controller regulates its flow by a manual set timer. The surface controller is set to open for a short period of time, a minute or less, so the high pressure gas can enter the side string, travel to the bottom of the tubing and push the water to surface. Once the gas pushes the column of water to surface, it follows the water into the flowline and goes back to the facility for separation, compression and recirculation back out into the lift lines. The next sequence is for controller to close for a set period of time, starting with 30 seconds. The shut time allows the water to flow back into the tubing once the tubing pressure decreases below the hydrostatic pressure of the column of water in the wellbore. This open and close cycle is continually repeated for the life of the well with the objective to get the fluid level below the producing formation. The side string pressure reading just before the controller valve opens is a good way to determine how much of a water column is inside the casing. Over time, the water production decreases, the gas production increases along with the CO_2 content of the gas. As the water production decreases the open and closed times are adjusted to compensate for a smaller column of water and longer fill time of the tubing. When the timer is closed for more than ten minutes, a plunger is dropped in the tubing making lifting the water more economical and efficient. The system is reliable and will move up to 350 bbls. water per day with very few moving parts.

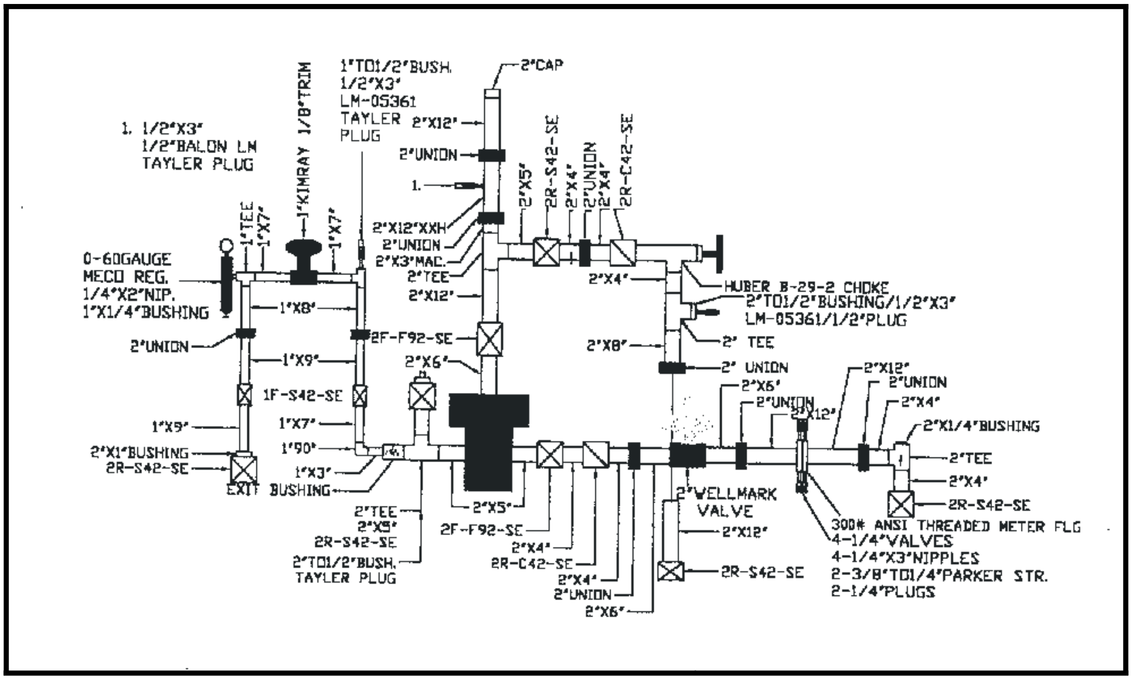

Figure 2
Schematic Diagram of Wellhead Assembly for DGL System

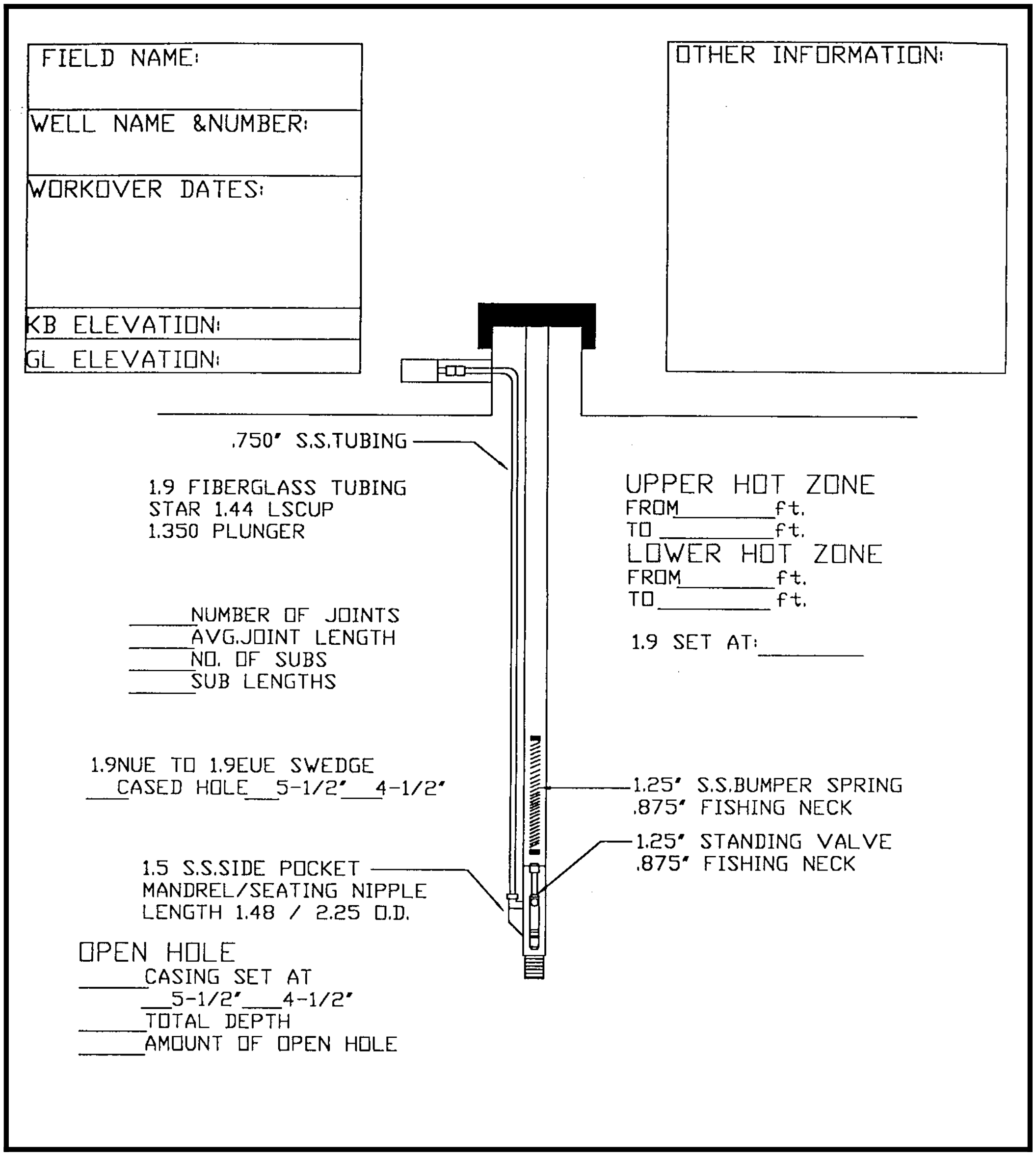

Figure 3
Downhole Configuration of DGL System

E S T I MATION OF METHANE EMISSION REDUCTIONS

The emissions that the DGL system gives off each day is 16.7 cubic feet of methane gas per well at maximum number of cycles. Over time, as the well starts dewatering, the emission volume decreases as the controller valve kicks off less and less. Eventually the timer may be kicked off a minimal amount of twice a day allowing the emissions to be less than .04 cubic foot per well per day. The only emission this system has is the bleed off on the Kimray 1" pressure open control valve that injects gas into the stainless steel sidestring. Each well will start off at the maximum cycles until the water level drops below the producing formation. After the water level is below the formation, the cycles can be cut back to take care of the daily produced water each wells makes. It can take anywhere from one month to one year to get the water below the producing formation.

The total methane emissions from a DGL system are less than 1% of those from either a conventional pumpjack system or progressive cavity (PC) pump. The methane emissions from each system were calculated as follows:

Antrim Shale Production Characteristics

Average Antrim Shale Recovery: 820 MMcf

Average Production Life: 15 Years

Daily Average: 150 Mcfd

<u>DGL System Emissions Calculations</u>

- Assume 6 months of dewatering at maximum number of cycles
- Assume 6 months of dewatering at 50% maximum number of cycles
- Assume 14 years of low rate dewatering

Emissions Calculations:

6 months x 30 days/month x 16.7 cf/day = 3,000 cf

6 months x 30 days/month x 8.35 cf/day = 1,500 cf

<u>14 years x 350 days/year x 0.04 cf/day = 196 cf</u>

Total Emissions, 15 Years = 4,696 cf or 4.7 Mcf

<u>Conventional Pumpjack System</u>

- Assume workover requires two days to complete
- Assume one workover every 1.5 years, or 10 workovers over 15 years

Emissions Calculation:

150 Mcf/day x 2 days x 10 workovers = 3,000 Mcf or 3 MMcf

<u>Progressive Cavity (PC) Pump</u>

- Assume workover requires one day to complete
- Assume one workover per year

Emission Calculation:

150 Mcf/day x 1 day x 15 years = 2,250 Mcf or 2.25 MMcf

COST SAVINGS AND BENEFITS

The operational benefits to the DGL system are it has only a few moving parts, the surface controller, plunger, (when dropped) and the ball that moves inside the standing valve. All of these components can be checked out with very little costs associated with doing so. The controller is at surface and the plunger can be caught at surface in the plunger catcher making both of these easy items to check and repair. The standing valve and plunger spring both have fishing necks on them and can be retrieved via an inexpensive wire line unit. The frequency of the wire line unit is every 1 ½ to 2 years. The potential for major mechanical problems (where you will need a rig to pull the tubing) do exist but happen about once every three years. All the major components in the wellbore, tubing (fiberglass), side sting, injection mandrel, and standing valve are all made of stainless steel so the acidic water does not have an affect on them and therefore almost no downtime or workovers from mechanical failures. The other systems use steel tubing and rods which have failures due to the acidic water eating away at them or wear out from moving that result in loss of production and costly workovers. The average DGL workover is done about once every three years compared to eighteen months for a pumpjack well and about once a year for PC pump. The average monthly LOE expense is approximately $275.00 for a DGL system compared to $450.00 for a pumpjack and $675.00 for the PC pump.

In addition to savings gained through lower operating costs, the value of the methane mitigated in the DGL system also needs to be considered. Using a conventional pumpjack would result in the loss of about 3 MMcf of methane over the life of the well. Using a constant gas price of $3.00/Mcf yields an additional $9,000 in income over the life of the well. With PC pumps, an additional $6,750 in revenue would be realized.

Other added benefits to this system is a single pumper is able to handle more DGL wells with very few movable parts compared to the other two systems that need daily checking of engines and movable parts. This results in a slightly lower pumper charge per well along with less costly repairs associated with replacing surface equipment. The DGL surface equipment is virtually maintenance free except for making sure the battery stays charged from the attached solar panel. It has very little noise associated with the system so it can be used in close proximity to residences or businesses with rarely any complaints about noise. The system is relatively small in size compared to the other systems so it receives less attention from landowners, surrounding homeowners or businesses.

PROJECT NUMBER 2

Company: LENAPE RESOURCES

Location: MEDINA SAND, NEW YORK

Project: CASING PLUNGER SYSTEM/LOGIC AUTOCYCLE/RABBIT PLUNGER SYSTEM

COMPANY OVERVIEW

Lenape Resources, Inc. is a small independent oil and gas producer with operations in Pennsylvania and New York. Lenape operates 69 gas wells in two fields producing from the Medina sand formation in Chautauqua County, New York. Production rates from these wells currently range from 1 Mcfd to 57 Mcfd, averaging just over 10 Mcfd.

Lenape's goal for participating in the program was to increase production and lower operating costs on four below average producing wells. These wells require additional labor to blow down the wells to remove produced brines from the wellbore. This process requires the wells to be open to the atmosphere allowing natural gas to be wasted.

OVERVIEW OF MEDINA SAND PRODUCTION IN NEW YORK

Natural gas has been produced in Chautauqua County, New York for many decades. The most significant gas reservoir in the area is the Silurian Age Medina Group of sediments, particularly the Whirlpool Sandstone Formation and the overlying Grimsby Formation. These two formations are separated by the intervening Cabot Head Shale Formation. In the study area, the Medina Group is found at depths from –1,450 feet to –1,800 feet, subsea. Generally speaking, the quality of the Whirlpool and Grimsby reservoirs is poor. Permeability and porosity are low. Continuity of individual sandstone beds and water saturation are variable in the Grimsby. However, natural gas is prevalent in a nearly continuous accumulation in the area, which is controlled more by stratigraphic than structural trapping mechanisms. Thus, Medina Group gas wells are characterized by a high drilling success ratio but low production rate, low ultimate recovery and a long producing life (25 years or more) at marginal economic conditions.

DESCRIPTION OF THE TECHNOLOGIES IMPLEMENTED

Two wells installed Jetstar casing plunger systems and the other two installed Logic autocycles with rabbit tubing plunger systems. The Logic autocycles are fully automated well head configurations and the Jetstars are manual wellhead configurations. Descriptions of each system are provided below.

Casing Plunger System

Automatic casing plungers combine the best features of several production methods to provide a simple economic method of removing wellbore fluids from the well and maximizing gas production. The ACS plunger is comprised of a hollow steel mandrel with an external traveling valve and 2 externally mounted rubber sealing elements. The external traveling valve is manipulated from open to closed depending upon its physical location of the well. The rubber sealing elements provide a barrier that traps reservoir pressure below the tool, separating it from the well fluids that have accumulated in the wellbore. The tool is approximately 3 feet long weighing about 65 pounds. The tool mandrel is 3.75 inches in diameter. The rubber sealing elements are manufactured with diameters ranging between 4.08 inches to 4.151 inches to accommodate various weight casings. The tool is equipped with multiple orifices which can be used to vary the rate which fluid is able to flow through the tool and thus altering the rate of descent as the tool free falls to bottom.

The ACS system includes a down hole stop that serves as the lowest point that the plunger may travel. The down hole stop determines the minimum amount of fluid volume which will remain on the formation between the top perforation and the bottomhole stop. The down hole stop may be either a casing stop or a tubing stop. The casing stop is designed to lock into the gap left in the collar between the threads of the upper and lower joints of the casing. Placement of the casing stand is predetermined by the location of the casing collars when the production casing was cemented. The casing stop is normally placed in the first or second collar above the top perforations, as indicated by the original perforating log.

A tubing stop is installed on the top of a predetermined length of freestanding centralized tubing that is lowered into the well on wireline. Electric wireline logs will provide the information to determine the length of tubing required to place the tubing stop above the top most perforations. Properly installed, both types of stands perform equally well, and the selection of stop types is often a matter of personal preference. A well which might produce significant amount of formation fines or frac sand is likely to “sand-in” a tubing stop and make it very difficult to recover.

A lubricator installed at the surface on the casing acts to catch the ACS plunger as it returns to the surface completing its’ cycle. As the ACS plunger enters the latches into the lubricator, the external traveling valve is simultaneously opened allowing gas sales to continue uninterrupted. The lubricator also serves as a storage facility, housing the plunger at the well site until the ACS plunger is dropped to begin another cycle. The lubricator can be easily “broken” open through the use of a hammer union to allow access to the ACS plunger so that routine inspection and required maintenance may be performed. A 3/8 inch orifice is installed in the lubricator to control the flow of gas from the well. This orifice is necessary to insure that the plunger is not traveling up the hole with sufficient velocity to cause the lubricator to fail when the plunger reaches the surface. The orifice also limits the velocity of gas coming up the casing so that the plunger is able to free fall to bottom in a reasonable period of time.

When engaged, the lubricator’s internal latching mechanism catches the ACS plunger as it enters the lubricator. The latch allows the operator the opportunity of retrieving the plunger for maintenance or to vary the plunger’s operation cycle. The latching mechanism can be coordinated with various timer or controller boxes to automate the operation of the ACS system. (NOTE: The above summary on casing plunger systems and the following summary on Rabbit plungers were adopted from SPE Paper 30981, "Automatic Casing Swabs: A Production System That Can Add Years of Productive Life to Wells" by Cramer and Wood, 1995).

Logic Autocycle/Rabbit Plunger System

The typical operating cycle of a rabbit plunger system well consists of cycling the well on and off with a controller box (Logic autocycle) and motor valve. Initially the well will be shut-in, and pressure and gas volume will build in the annular space between the tubing and the casing. At a predetermined time or pressure, the controller box signals the motor valve to open the sales line valve, then the gas trapped in the annulus helps push the rabbit and the fluid trapped in the tubing above the rabbit to the surface. The excess pressure that is stored in the annulus is used to overcome the producing line pressure and chase the rabbit to the surface. The body of a tubing rabbit is machined to have an external diameter slightly smaller than the internal diameter of the tubing in which it will run so that it can easily travel up and down the tubing. The tubing rabbit relies upon turbulence in the fluid immediately above the rabbit to minimize the amount of fluid that gets by the rabbit as its travels to the surface. Lacking positive pressure sealing elements, a rabbit must achieve a velocity of 800 to 1000 feet per minute to create an adequate seal between the rabbit and tubing to minimize the fluid that can get by the rabbit. If the rabbit is not able to reach the surface, it will stall and fall back to bottom along with any wellbore fluids that have not reached the surface. This increased fluid column would require additional pressure and volume to lift the rabbit on the next trip.

ESTIMATION OF METHANE EMISSIONS REDUCTIONS

Production rates for the four (4) wells targeted averaged approximately 1.4 Mcfd per well at the start of the project. The maintenance schedule required the wells to be blown down on average 3 times per week, with an open time of approximately 2 to 3 hours each time. In addition, the wells were on a swabbing schedule which required the wells to be swabbed every three years with an open time of approximately 6 hours. It was anticipated that the autocycles would eliminate the open blow period and the casing plungers would reduce the open blow period to 30 minutes. The swabbing requirement should be eliminated.

Emissions Reduction Calculation:

Blow-Down:	**1.4 Mcfd x 0.125 days x 3 times/week x 52 weeks x 25 years =**	**682.5 Mcf**
Swabbing:	**1.4 Mcfd x 0.25 days x 8 swabbings =**	**2.8 Mcf**
	Total Emissions Reduction, 1 well =	**685.3 Mcf**
	Total Emissions Reduction, 4 project wells =	**2,741 Mcf or 2.7 MMcf**

While the 2.7 MMcf of emissions reductions over 25 years for the 4 wells studied does not appear significant, if one considers that there are about 500 Clinton-Medina producing wells in New York with an average production of 10 Mcf/day, total methane emissions exceed 3.4 Bcf for New York alone over a 25 year period. At the national level, there are 192,000 stripper gas wells (wells with production rates of 60 Mcfd or less) many of which are suitable candidates for plunger lift systems. If we assume one-half of these wells are candidates for plunger lift systems and their average daily production is 30 Mcfd/well, the total annual methane emissions from these wells would be reduced by 3.5 MMcfd to 5 MMcfd per year.

COST SAVINGS AND BENEFITS

The technologies for this project were implemented to increase production, lower operating costs, and lower fugitive methane emissions to the atmosphere. The program has been successful; average well production has increased to 8.5 Mcfd from 1.4 Mcfd, operating costs have been lowered and methane emissions reduced. The economic benefits of this program on a per well basis are calculated as follows:

a. Increased Production	
7.1 Mcfd x $3.00/Mcf x 360 days/year x 25 years =	$191,700
b. Decreased Labor	
2 hrs/week x $25.00/hr x 52 weeks x 25 years =	$65,000
c. Value of captured methane	
685 Mcf x $3.00/Mcf =	$2,055.00
Total Potential Economic Benefit, per well	**$258,755**

PROJECT NUMBER 3

Company: UNION PACIFIC RESOURCES/ANADARKO PETROLEUM CORPORATION
Location: SOUTH CARTHAGE FIELD, C.E. MOORE AND J.R. KYLE COMPRESSION FACILITIES, E. TEXAS
Technology: LOW BLEED CONTROLLERS

COMPANY

The project was originally signed with Union Pacific Resources (UPR). However, in July, 2000 UPR merged with Anadarko Petroleum Corporation (APC). Anadarko Petroleum Corporation (APC) is an independent oil and gas exploration and production company, with 991 million energy equivalent barrels of proved reserves as of December 31, 1999. About 71% of the Company's total proved reserves are located in the U.S., primarily in the mid-continent (Kansas, Oklahoma and Texas) area, offshore in the Gulf of Mexico and in Alaska. APC also owns and operates gas gathering systems in its U.S. core producing areas. The Company also participates in other exploration projects in Tunisia, the North Atlantic Margin and other selected areas. The Company's subsidiaries are Anadarko Algeria Corporation, Anadarko Energy Services Company and Anadarko Gathering Company.

UPR agreed to participate in the project by replacing six (6) continuous bleed controller valves with low bleed controller valves at their C.E. Moore and J.R. Kyle Compression Facilities in the S.E. Carthage Field of East Texas. The S.E. Carthage Field produces from the Cotton Valley Formation, a tight gas sand.

OVERVIEW OF COTTON VALLEY PRODUCTION

Stratigraphically, the Jurassic Cotton Valley defines a group, of which the Cotton Valley sand (Schuler), Bossier Shale, and Cotton Valley Lime (Cilmer or Haynesville) are members. All are present throughout the basin although productivity varies. Depth to top of the Cotton Valley ranges from less than 8,000 feet by the Sabine and Monroe Uplifts, to more than 12,000 feet to the west and south.

The general stratigraphic framework of Cotton Valley Sandstone in Texas is similar to that of Travis Peak. The Cotton Valley is generally fine to very fine quartz sandstones with a minor mud matrix. Delta-front deposits are overlain by a thick wedge of braided-stream sediment that forms part of a fan-delta system or wave-dominated delta system that deposited most of the terrigenous clastic sediment of the Cotton Valley Group.

In the terminology typically applied to the East Texas Basin, “Cotton Valley” describes a group as well as a limestone and sandstone within that group. The terms “Haynesville” and “Schuler” are more frequently applied to Northwestern Louisiana. The Schuler Formation, considered to be the updip equivalent to the entire

Cotton Valley group in Louisiana, includes red sandstone and shale and is locally conglomeratic. Other usage refers to the Schuler as the sandstone unit above the Bossier Shale. In Louisiana, the Knowles Limestone, an argillaceous limestone alternating with thin shale, forms the upper-most unit of the Cotton Valley group (this unit is less well defined in Texas). The Terryville Sandstone in Louisiana is, in part, equivalent to the Cotton Valley Sandstone in Texas.

Producing Cotton Valley Sandstone is generally of two types:

- Porous and permeable blanket-geometry sandstone that readily produces gas on open-flow drillstem tests; and
- Low-porosity, low-permeability, fine-grained, massive, undifferentiated sandstones that do not flow on drillstem tests and that require massive fracture treatment for commercial production.

The blanket-geometry sandstone trend occurs only in Louisiana, and this trend was at a mature stage of development in the early 1960s. The low-permeability, massive sandstone trend occurs downdip of the blanket sandstone trend throughout much of Texas and Louisiana. Formation thickness of the Cotton Valley generally are about 1,000 to 1,400 feet in East Texas with subsea depths ranging from 7,000 feet on the northern and western margin of the basin to 7,500 feet over the Sabine Uplift to 13,000 feet on the southern basin margin.

DESCRIPTION OF THE TECHNOLOGY IMPLEMENTED

UPR/Anadarko converted constant bleed controllers to low-bleed controllers at their C.E. Moore and J.R. Kyle compression facilities in East Texas. At the C.E. Moore Facility, two continuous bleed controllers were replaced on the inlet separators and one on the compressor. At the J.R. Kyle Facility, one inlet separator valve was changed along with two compressor controller valves (Figures 4 through 7). Low bleed controllers “snap” from closed to fully open over a very short portion of the float arc and they rely on a float arm that travels through a significant arc. These controllers tend to be inexpensive, very simple, and rugged.

While the vessel is filling, the controller shuts off gas from the instrument-gas system to the motor valve.. When the liquid level in the vessel reaches the set point, the controller opens rapidly and send gas to the motor valve. When the liquid-level reaches the lower set point, the controller closes off supply and vents the motor valve and piping to atmosphere. The emissions are based on control-system volume, instrument-gas pressure, and dump frequency.

Figure 4
C.E. Moore Inlet Separators

Figure 5
C.E. Moore Compressors

JAF00920.PPT

Figure 6
J.R. Kyle 3-Stage Compressor Separator

JAF00920.PPT

Figure 7
J.R. Kyle Inlet Separator

ESTIMATION OF METHANE EMISSIONS REDUCTION

Methane emissions were reduced by about 98% after the installation of the low-bleed valves. The estimated methane emissions from the constant bleed controllers that were replaced were calculated as follow:

0.7 cf/minute x 60 minutes/hour x 24 hrs/day x 350 days/year = 352 Mcf/year

Low bleed controller emissions were calculated as follows:

0.014 cf/cycle x 1 cycle/minute x 60 minutes/hour x 24 hrs/day x 350 days/years = 7.4 Mcf/year

For the six valves replaced at the two compression facilities, these retrofits represent an emissions reduction of just over 2 MMcf/year.

COST SAVINGS AND BENEFITS

The incremental annual revenue from the installation of a single low-bleed controller is $1,034 (assuming a $3.00/Mcf gas price) or just over $6,200 for all six controller valves. At a cost of $415/unit, the cost to replace constant bleed controllers with low-bleed ones is repaid within about 3 months. Simpson and Jensen (2000) report similar economic benefits through the conversion of constant bleed to low/no-bleed controller valves at a project conducted by BP Amoco.

PROJECT NUMBER 4

Company: TRINITY ENERGY CORPORATION
Location: DENVER-JULESBURG BASIN
Project: TUBING PLUNGER LIFT SYSTEM

COMPANY OVERVIEW

Trinity Energy Corporation was founded in 1997 for the purpose of acquiring producing oil and gas properties. Trinity has interests in approximately 400 wells in Colorado, Pennsylvania and New York..

Trinity's operations in Colorado consist of approximately 100 wells ranging in depth from 5,000 to 8,100 feet. Approximately 20 of the wells operate with a pumping unit to remove oil and water from the wellbore. Several of the pumping unit wells also produce gas. A few of the pumping wells produce a quantity of gas that may be sufficient to run a tubing plunger, a method which is significantly less costly than a pumping unit and would reduce methane emissions to the atmosphere by the need for well workover.

OVERVIEW OF D-J SAND PRODUCTION

D Sand

The Upper Cretaceous D Sandstone play in the Denver Basin encompasses northeast Colorado and southwest Nebraska. Cumulative D Sandstone gas production in Colorado is 441 Bcf from 378 reservoirs, 24 of which are major (>5 Bcf). Cumulative oil production from the D Sandstone in Colorado is 168.7 million bbls. Gross thickness of the D Sandstone interval in the fairway ranges from zero depositional edge to 100 ft. Maximum depth to production of the D Sandstone reservoirs is approximately 8,200 ft in northwest Elbert County; minimum depth is about 4,000 ft in east-central Washington County. The dominant trapping mechanism is stratigraphic. Average porosity of the D Sandstone in the play's major reservoirs is 15%, average permeability is 187 md. Typical D Sandstone completions consist of running 5-1/2" production casing to total depth, selectively perforating pay zones, and stimulating with a small-volume acid frac. In tighter pay zones, operators follow the acid frac with a small to medium sand frac before placing the well in production.

Muddy (J) Sand

The Lower Cretaceous Muddy (J) Sandstone has produced 1.058 Tcf of gas in Wyoming and Colorado portions of the Denver Basin. Cumulative oil production for the Muddy (J) Sandstone in the two-state area is 298,201,041 bbls. Gas/oil ratios vary widely in individual reservoirs, but generally they are much lower in the shallower accumulations.

The Muddy (J) Sandstone in the subsurface of the Denver Basin is informally called the J or J sand by most operators and service companies. Muddy (J) Sandstone thickness ranges from a few feet to approximately 150 ft in the Denver Basin, although it generally is less than 100 ft thick (Higley and Schmoker, 1989). Production depths range from a maximum of 8,400 ft at the south edge of Wattenberg field in Adams County to a minimum of about 3,900 ft in some of the small east Washington and Logan County fields. Most Muddy (J) Sandstone production is from stratigraphic traps; however, subtle paleostructure and unconformities also have played a role in trapping production (Weimer and Sonnenberg).

Median core porosity in the Muddy (J) Sandstone decreases from 24% at depths of about 4,000 ft to 7 to 10% at depths of 9,000 ft. Median core permeability for the Muddy (J) Sandstone for the same depth range is 200 md at 4,000 ft to 0.1 md at 9,000 ft. For the basin as a whole, the channel-sandstone sequences of the Horsetooth generally have higher porosities and permeabilities than the deltaic sandstones of the Fort Collins (Higley and Schmoker, 1989).

Completion practices vary widely for the Muddy (J) Sandstone. Generally the shallower, more porous and permeable east basin wells were completed naturally or were stimulated with small acid treatments followed by moderate oil or water/sand fracs. In contrast, the deep basin, tight gas sand area of the Wattenberg Muddy (J) requires massive hydraulic fracturing to achieve commercial production.

DESCRIPTION OF TECHNOLOGY IMPLEMENTED

In the fall of 1999 Trinity installed a tubing plunger on a well that had previously only produced with the operation of a pumping unit. The tubing plunger operation has operated continuously for the past 6 months. The tubing plunger removes fluid (oil and water) from the wellbore using the natural pressure of the well. A timeclock – controller at the surface shuts the well in for a pre-determined period of time in order to allow the pressure to build up in the well. After a desired pressure level is reached, the controller opens a valve allowing the plunger to more up the tubing (with fluid above it) until it reaches the surface. The fluid is produced in to a tank and the gas is sold into a gas sales pipeline. After a certain period of gas sales, the valve is automatically closed and the plunger falls back to the bottom of the well. The cycle than starts over.

ESTIMATION OF METHANE EMISSIONS REDUCTION

Wells operated using a conventional beam pumping unit (Figure 8) in this field require workovers of the downhole pumps one to two times per year. During this well work, the well is open to the atmosphere and methane escapes to the atmosphere for a period of one to two days. On these low volume producing wells, averaging about 15 Mcfd, there is no way to economically capture the escaping methane. The goal of switching to a plunger lift system (Figure 9) was to reduce workovers as tubing plunger systems typically experience significantly fewer operational problems requiring the use of a service rig.

Figure 8
Beam Pumping Unit, Trinity Energy Corp., D-J Basin

An estimated 41 Mcfd/well of emissions would be prevented by changing from beam pumping units to tubing plunger systems as shown below:

<u>Conventional Beam Pump</u>

15 Mcfd x 2 days of open flow x 1.5 workovers/year = 45 Mcfd/year/well

<u>Tubing Plunger System</u>

15 Mcfd x 0.5 days of open flow x 0.5 workover/years = 3.75 Mcfd/year/well

COST SAVINGS AND BENEFITS

Trinity Energy estimates that annual operating costs will be lowered by approximately $4,000 using the new plunger lift system. Incremental revenues from the capture and sale of previously vented methane will be about $124/well (assuming a $3.00 gas price) or about $2,500 when all twenty wells are converted.

Figure 9
Plunger Lift System, Trinity Energy Corp., D-J Basin

REFERENCES

Simpson, D. and Jensen, J., "Vented Gas From Wellsite Control Equipment", SPE Paper 61030, SPE International Conference on Health, Safety, and Environment in Oil and Gas Exploration and Production, Stavanger, June, 2000.