Design Development and in Well Testing of a Prototype Tool for in Well Enhancement of Recovery of Natural Gas Via use of a Gas Operated Automatic Lift Pump

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By

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Brandywine Energy and Development Co. (BEDCO)

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Title of Project: "Design Development and in Well Testing of a Prototype Tool for in Well Enhancement of Recovery of Natural Gas" Via use of a 'Gas Operated Automatic Lift Pump"

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Abstract

A 'Gas Operated Automated Lift Pump' has been conceptually developed constructed in prototype and determined to be applicable for use in removing fluids from "stripper wells" thereby increasing production of natural gas. Bench scale and laboratory test of the key tool component, the automated pressure controlled valve assembly, has established the potential applicability of a prototype tool in watered out stripper wells. Tool applicability is targeted to operating conditions of 50 to 600 psi down hole pressure with brine and fluid lift capacity varying from 0.1 to 6.0+ BBL/ tool cycle. In field precursor testing of a pilot predecessor tool of larger dimensions and weight than that targeted for fabrication and deployment as part of the SWC program has shown promising results. A precursor field test of tool [s] have shown improved natural gas production 1.6 X to 2.4X, regular automatic cycling of tool [1 Trip each 1 – 1.5 Day] and auto lifting of brines [0.33 – 1.5Bbl/cycle] from a brine producing natural gas stripper well. Field testing of the above referenced designed prototype tool for this phase of the project showed similar brine production [0.25 to 1 Bbl/ tool run with 1 to 2 day cycles] and frequency of tool cycles during the early period of field trials. Field trials of the new prototype tool evidenced metallurgy problems in materials construction compatibility resulting in premature actuator failure and decreasing frequency of tool runs and lesser quantity of fluids production with each subsequent tool trip. Field and laboratory analysis have diagnosed the problem and designed a remedy for further in field-testing. This premature failure was diagnosed as corrosion on one of the actuator components. The problem occurred as a function of miniaturizing of components to achieve a desired, "well tender friendly" smaller tool configuration. Additional lab trials and in field testing of the smaller prototype tool with a modified more corrosive resistant actuator are scheduled for the 4th calendar quarter of 2002. This work will be conducted by BEDCO as part of its on going commitment to establish working G.O.A.L. Tool technology to assist in the production of gas and oil from the nations aging stripper wells. This work will be supported by the SWC and NYSERDA in a follow on award for field trials of G.O.A.L. PetroPump Tools.

The cost of the G.O.A.L. PetroPump and the attendant well head modifications in comparison to the improvements of gas production achieved by the prototype tools, at current market prices of $3.00 Mcf, suggest a potential payback on capital investment of 1 to 1.5 years.

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INTRODUCTION

The following is the final report under DOE NETL Prime Award No. DE-FC26-00NT41025, Subcontract No.2052-BEDC-DOE-1025 on the development of a prototype tool for the automatic lifting of brines with subsequent improved gas flow production from watered out stripper wells. This feat is accomplished through the use of an on tool automated pressure-sensing/ actuating value that is preset to pass through a predetermined volume of brine with subsequent lifting of that brine to a surface process unit and brine tank. The energy for that lift is powered solely by in well geologic formation pressure.

EXECUTIVE SUMMARY

More than 8% of the US natural gas production is derived from "Stripper Wells" averaging approximately 15-mcf/ day. Much of the United States and the world's natural gas producing wells suffer from declining and restricted production due to the presence and build up of brines in the well bore. Conventional techniques for addressing and or removal of the brine are cumbersome and costly. The scope of this project is to develop an alternative technology [total fluids pump] for the automatic lifting of that brine/ fluid to the surface using in well down hole pressure to activate an in tool valve. This sensing control valve is automatically held open by an internal pressure sensing mechanism allowing the tool to drop into the fluid column in the well. Passage ways through the tool allow passage and accumulation of brine atop the tool to a preset column thickness at which time the on tool pressure sensing mechanism closes the tool valve. This closure is accomplished via the combined hydrostatic pressure of the brine atop the tool and system backpressure. An in well down hole seal of the tool to the casing is accomplished by a set of dual flex cups which surround the tool and make circular contact with the well casing. Subsequently tool and fluid column are lifted to the surface driven by below tool formation pressure [in well below tool pressure].

In the work completed to date on this project BEDCO has confirmed the need for and applicability of an automated tool, which will remove, accumulated fluids [brines] from gas wells and increase gas flow. BEDCO has confirmed these needs and results of increased gas yield post brine removal from wells via meetings, work sessions, well records review, interviews with well field owners and operators and preliminary production response from predecessor tools. These owners and operators currently use sundry methods of brine removal to produce gas from their stripper wells. Interviews with both well owners and operators speak to a common problem in production of natural gas from stripper wells using conventionally available techniques. That problem being, that current production techniques and tools for removal of fluids [Brines] leads to intermittent and often irregular production of gas from stripper wells and certain process unit problems such as winter icing. A need for regular automated fluid removal and more uniform gas production is desired and needed.

BEDCO has produced and bench tested a prototype tool to meet industry needs and simulated in field testing with a 98% adherence/ correlation to the designed tool plan.

BEDCO has further begun to define the numbers and types of wells applicable for such an automated tool through technical work and review sessions evaluating tens to hundreds of "stripper wells' production records with a regional natural gas producer. The number of wells for which the technology is applicable in the Appalachian Region, in the tools current configuration [i.e. sized for 4 to 6 inch ID wells], are numbered in the high thousands. Through out the country, and with further miniaturization of certain tool components the, wells for which the technology is applicable number into the tens of thousands.

The completed work to date on bench tools and prototype tools for field use has focused on tool design and construction of durable materials that are tolerant of down well physical and chemical conditions. To that end materials of construction are Hastelloy, 316 stainless steel for all tool body parts and condensate tolerant synthetics materials for tool sealing cups and BUNA-N materials for automated valve seats. Tooling and machining of components, assembly processes for components and current generation production prototypes are so configured to match with or lend themselves to standard oil and gas field specifications and conditions of service tool [s] availability and technician capability. A field demonstration tool of 32" in length and 42# of total weight has been manufactured and is under ongoing bench testing to determine performance characteristics and simulate in well/ in field-testing. Installation for this new tool design in a chosen Lenape Resources Inc. natural gas well # 52 occurred in March 2002. The well physical characteristics are show in Table 1 - 1 in the Appendix.

It has been determined from predecessor [larger] tool testing that variable tool response is necessary to optimize the performance to low pressure wells and low volume fluid production from certain stripper wells. To address such needs BEDCO has developed bench test apparatus for mock up tool configurations to simulate and address the need for variable stroke and valve seat configuration design to address variable well conditions related to geology conditions and life cycle of the well. Further this apparatus has been and is used to calibrate assembled tools for in field-testing. As noted previous, in field tool testing with prior generation pilot tools has confirmed this need and ability to adjust the tool to wells with lower down hole to well head pressure differentials and lighter brine [fluids] loads. It is also apparent from this testing that smaller pressure sensor control mechanisms would allow for construction of a smaller tool and accommodate a wider selection of candidate wells. Producers express interest for a 2 to 2.5" diameter tool.

Development of real time metrics which will quantify the results of the tool deployment and in well testing as well as provide detailed information for refinement of construction and operation of the tool are critical to the project success. We have determined that the oil and gas industry has begun to address these needs with a limited number of first generation continuous data loggers targeted to collect some of the key pressure and flow data associated with operating wells. BEDCO has further 'in field" deployed and initiated configuration of one such data logger unit on a test well to confirm its use and applicability to the "Prototype Tool".

EXPERIMENTAL

SIMULATION AND ANALYSIS

Analytic modeling was developed to assess candidate fluid lift pump configurations. Analytic simulations indicated that the pressure at which a sensor controlled valve will closed is controlled, to a first order, by the sensor-actuator compression ratio, spring force plus valve and shaft weight, and the initial sensor-actuator charge pressure and charge temperature. Additionally it was concluded analytically, that the pressure at which a sensor-actuator controlled valve will open, once closed, is related, to a first order, only to the ratio of the sensor-actuator cross-sectional area to the valve cross-sectional area, the pressure above the valve, and the pressure below the valve. Based on these understandings, various valve and sensor-actuator geometry were analyzed and alternative configurations and operating strategies were evaluated.

DEVELOPMENT TESTING

A development test program was designed to correlate the analytic modeling and to provide calibrations for development of fluid lift pumps.

The test vehicle consisted of a tubular section containing, and supporting, a sensor-actuator assembly. This was attached to a cylindrical valve seat assemble. A valve shaft was attached to the lower [free] end of the sensor-actuator in such a way that as gas pressure [forces] compressed the sensor-actuator the valve head was pulled up into the valve seat. Upper and lower pressure caps were attached to the cylindrical assembly. Bottled nitrogen plus control valves and gauges completed the test set up. Testing was also conducted with test items immersed at pressure under water. The results indicate no significant difference between water and air [gas] testing.

Tests were initiated with the sensor-actuator-controlled valve in the open position. Gas pressure was increased below the valve, filling and pressurizing the total test vehicle, until the sensor-actuator assembly compressed closing the valve. This simulated the fluid pump descending into the well, being exposed to the flow pressure and hydrostatic fluid pressure, and eventually shutting in the well. The testing established the validity of the analytic modeling of in-well valve closing providing an analytic basis for design modifications.

Each test was continued to simulate the fluid pump arriving at the well head. The pressure above the sensor-actuator-controlled valve was bled off; corresponding to that which would be dissipated into the tank and sales line as the fluid pump approached the surface. The pressure above the sensor-actuator, in the test vehicle, was varied parametrically from one to five atmospheres to assess the validity of the analytical modeling. The pressure below the valve, and sensor-actuator, was reduced until the valve opened. This represented the reduction of well flow pressure that would result as the gas was discharged from below the liquid pump. Once again, the experimental data was in good agreement with analytic predictions of the conditions necessary for valve opening. Analytic modeling was used to evaluate alternative fluid pump designs and operating strategies.

FLUID PUMP CONFIGURATIONS

Two sensor-actuator diameters and several valve head configurations were tested over a range of simulated operating conditions. A liquid pump design was tentatively selected, fabricated and tested. Sensor-actuator compression ratios were varied (stroke adjustments) and sensor-actuator charge pressures were selected parametrically to characterize the liquid pump development model. Figure 1 represents sample results of development testing for the selected configuration (hundreds of test have been conducted with a variety of configurations).

FIGURE 1 Gas Operated Automatic Liquid Pumping System (fluid pump)

Bench testing of TOOL #1 with a reduced stroke. August 10, 2001

Summary: Calibration testing of Tool #1 was conducted with a reduced stroke of about 1.05"

Test Results: (Pressure are PSIG) Stroke about 1.05 inches (+\- .02")

Charge Pressure	Valve Closing Pressure	Pressure above Valve At Valve Opening	Opening Pressure	Absolute Pressures Calculations Pcharge	Pclose	Popen	Po/Pc	Pa/Pc
20	58	20	32	34.70	72.70	46.70	0.64	0.48
20	58	0	20	34.70	72.70	34.70	0.48	0.20
20	55	0	18	34.70	69.70	32.70	0.47	0.21
20	56	0	18	34.70	70.70	32.70	0.46	0.21
20	55	30	40	34.70	69.70	54.70	0.78	0.64
20	55	30	40	34.70	69.70	54.70	0.78	0.64
20	57	20	32	34.70	71.70	46.70	0.65	0.48
30	70	30	43	44.70	84.70	57.70	0.68	0.53
30	70	30	44	44.70	84.70	58.70	0.69	0.53
30	73	30	44	44.70	87.70	58.70	0.67	0.51
30	70	50	59	44.70	84.70	73.70	0.87	0.76
30	70	60	65	44.70	84.70	79.70	0.94	0.88
50	106	50	66	64.70	120.70	80.70	0.67	0.54
50	107	30	51	64.70	121.70	65.70	0.54	0.37
50	107	20	42	64.70	121.70	56.70	0.47	0.29

In all testing, the calculated absolute pressure ratios (that is, valve opening pressure/valve closing pressure, and pressure above the valve at opening/valve closing pressure) can be characterized by a straight line plot, the slope being determined by the ratio of the sensor-actuator effective cross-sectional area to the valve seating cross-sectional area.

Specifications have been developed for the fabrication of two alternative sensor-actuator configurations; one with a reduced diameter (1.70" vs. 2"), and both with longer available strokes (20% increase). Discussions are in process with suppliers.

RESULTS AND DISCUSSIONS

The project has been broken down into six major tasks. Those work tasks and the status of activities on those tasks are outlined below:

1.0 COMPLETE DESIGN OF PROTOTYPE TOOL

1.1 The project senior engineering, senior manufacturing and scientific personnel have conducted meetings and work sessions with field engineering/ well operations personnel to outline field durability needs, assembly, adjustment, ease of installation and service specifications for the prototype tools. Findings to date indicate the obvious needs for chemical compatibility with down hole chemistry. This is addressed via the use of Hastelloy, 316 stainless steel metallurgy and valve seat [Buna N] and sealing cup chemistry that will be tolerant of both brine and condensate. Additional findings go to near term application of the tool in 4 inch casing wells and longer term application of tool use in tubing of 2.5 inch or smaller diameter. Immediate needs for the 4 inch cased wells need to address tool total weight, total length, and assembly/ deployment/disassembly of tool components in the field.

1.2 Specific elements that have been addressed are the length, weight and tool diameter to allow for maximum use in varying type of wells and minimum amount of reconfiguration of well head and associated cost. Ancestral tools were in excess of 6 feet in length and 105 pounds in weight. Operating predecessor prototypes for the tool under current design/construction reduced length to 46 inches and weight to ~54 pounds. The tool constructed and bench testing for deployment and testing for the SWC 2002 project is 32" in length and weighs ~ 42 pounds. This design and construction configuration allows ease of deployment of the G.O.A.L. PetroPump and retrieval by a well tender with minimal changes in configuration to a typical well head lubricator.

1.3 Another specific element determined in field meetings for tool modification is the component assembly characteristics. Field assembly, disassembly and adjustment must be possible with the fewest number of field tools and personnel to assist. To that end, tool design and construction has been simplified and addressed to oil and gas industry standards. This includes only three- [3] field serviceable disconnects and these are constructed with standard 6 pitch General Acme threads. Components have been reduced from 27 or more in predecessor tools to 14. Basic material for the tool body is commercially available durable 316 stainless steel. Minimum steps for tool assembly and large milled tool flat areas [wrench flats] complete the simplified design and assembly. This design/ construction/ assembly approach all lends itself to service and maintenance work by standard industry tools [i.e. 36" and 48" pipe wrench, 18" and 24" adjustable wrench and 3# and 5# hammer].

1.4 Field and bench testing has lead to further tool modification of valve seal mechanism improving simulated and field confirmed results with the SWC new designed tool.

1.4 Project senior engineering, manufacturing and scientific personnel have conducted work sessions and have completed a prototype tool in conjunction with the specialized machining firm of Eagle Tool and Die. The tool has completed bench testing and well simulation testing. The, "user friendly", smaller tool was installed in a test wells in March 2002. To achieve the above referenced reduced size and weight of tool, senior engineering designed for the use of a new design and constructed [20 % smaller diameter] self actuating control mechanism for the automated control valve. This major change in design and construction fostered other reductions and size leading to the decreased tool length of ~15" from predecessor tools to the current 32" prototype for SWC in well demonstration and decrease in weight of ~12 pounds to a current weight of ~42 pounds. These represent significant changes, which lend them self to one-man installation and ease of use and retrieval. In process drawings and list of materials stock for machining of components have been simplified in form and reduced in total numbers of components to 14 from 27. The drawings and materials stock list are completed. The documents have been reviewed by the joint team to determine the possibility of further simplification and reduction in component parts. Valve actuator protection against over-pressurization from ambient forces down well was determined as a potential factor in tool operations and design/ construct compensated.

1.5 Project senior engineering in conjunction with the manufacturing director have designed, constructed, modified and refined a bench testing device on which the prototype tool has and was tested prior to and post in field testing. Lab testing of varying pressure [equating to differing in well brine head/ pressure] simulations has been tested to confirm viability and operational integrity of the constructed bench testing equipment and tool critical components. Changes in the actuator stroke and seating area of the self actuating valve assemble have been subject to test to allow for and confirm potential for operation in low pressure and small brine/ fluid load environments.

1.6 Specifications and modifications to the pressure sensing [valve control] device for the operation of the in tool automatic valve have been developed from the above completed meetings, work sessions and test stand work with specific reference to targeted installation wells.

2.0 CONSTRUCT AND BENCH TEST PROTOTYPE TOOL

2.1 The prototype tool was constructed and bench tested against design parameters to which it adhered with greater than 98% correlation. The tool was in lab modified to accommodate learned information from predecessor on going field test to avert over pressurization by ambient forces in down hole conditions. Well operation simulation testing is on going as part of company QA/QC and product evolution.

3.0 SELECT CANDIDATE WELLS

3.1 Meetings and work sessions with Lenape Resources Inc. have been conducted to assemble a list of candidate wells and choose a well for testing of the "Prototype Tool".

3.2 Starting with a list of more than 200 operating and shut in stripper wells a short list of more than 50 wells was assembled. This short list was further refined to 2 target wells. From those two alternative wells, LRI # 52 was chosen for testing.

3.3 Considerations evaluated in choosing LRI # 52 include total yield over time since completion, current yield, and history of fluid production, decline curves and previous testing database.

- As noted above, two alternative test wells were considered. LRI # 52 and LRI #29 were subsequently evaluated for field tool use and evaluation.
- Data on these wells is shown in the appendices
- LRI # 52 had been previously tested with predecessor tools and has the most complete available history of technical data for evaluation and comparison of the many variables associated with gas production which makes it a technical favorite for testing and analysis. The well however is associated with a sales/ gathering system which periodically [especially during low commercial gas demand] that pressures up to in excess of 100 psi versus normal operating pressures of 50 psi making gas production from the well under those conditions onerous.
- Well LRI # 29 as a candidate has less data base and history of close watched operations, but has an advantage of being produced into a sales line with an LRI owned/ operated compressor station which theoretically can minimize wide/ wild swings of back-pressure on the system.

3.5 Associated data on water/ brine production on these wells and other back up candidate wells is continuing to be assembled along with well response [production] information related to intermittent or regular removal of those brines. The final choice of test well was made upon data review and completion of tool assembly with in field-testing initiated in March of 2002 on well # 52.

4.0 TEST WELL PRODUCTION

4.1 Quantification of gas production before, during and post "Prototype Tool' deployment is a key element on the development of metrics to confirm applicability and success of the tool. Current technology on most wells for quantification of gas yield and pressure is performed by analogue instrumentation. This analogue instrumentation is tied to a specific orifice plate size in the well process unit and recorded on a circular 'pie' chart. The charts are subsequently integrated and quantified by third party off site contractors at a later date.

4.2 The project scientist and engineers have assembled some of this analogue data as it relates to the target well for in field-testing and continue to assemble review and interpret this historic data. Production from this well meets targeted test parameters. Those parameters include down hole pressure and historic production challenges which between the period of 1994 to 1999 showing low to no gas production from this well # 52 prior to physical swabbing / brine removal with a work over rig to remove several tens of barrels of brine.

4.3 In field process production data from a larger and heavier predecessor tool is also undergoing analysis and was used in final fabrication of the SWC prototype test tool and wellhead modification parameters. Reduced data to date from this predecessor tools shows an increase gas production from [2] two stripper wells of >1.6X to 2.4X. Regular tool automatic cycles at 1cycle each 1-1.5 days with 0.3 to 0.8 barrels of fluid produced per cycle @ 15 to 20 cycles/ month yielding 8 to 10 barrels/ month of brine are recorded. In well and at well head operating conditions evidence typical pressure ranges expected for the SWC test of 50 to 60 psi backpressure and down hole pressure conditions of 100 to 150 psi.

4.4 Real time comprehensive data collection of well head, process unit and sales line pressure and flow are critical to thorough comprehension of well and tool operation. To that end BEDCO has acquired and deployed a digital recording data logger to capture this type of information. Digital data loggers can collect comprehensive "real time" data at the well head and the process unit. Technical information was first assembled on manufactures and suppliers of continuous recording digital data loggers [well head computers] to collect and log both volume yield and pressure through out the well head and process unit system.

4.5 Bids were solicited for the purchase of a unit most applicable to project needs.

4.6 A successful bidder/ supplier of the well head data logger has been selected. The unit wellhead computer, solar panel and battery] has been purchased installed and field-tested.

4.7 The components of the unit have been field installed on a chosen data collection/ confirmation well in the Lenape Resources System. Unit software and sensors have been installed and calibrated. Results to date show accurate relative correlation with analogue recording charts on the well and the ability to collect and recorded data in digital form on as frequent as 1-minute intervals. Down load of system data via cellular link has been proven viable. Soft ware challenges in manipulating the data for accurate/ absolute correlation/ comparison on a 1 to 1 basis were worked on by BEDCO and the equipment manufacturer to achieve in field data collection/ recording and telephonic down loading success.

4.9 Preliminary field recorded data has been retrieved, downloaded and formatted for correlation with the analogue data from the well. An example of incremental data being recorded is presented in Figure 2. Daily summary data is also available.

Figure 2

HOURLY REPORT
FLOW AUTOMATION CORP.
HOUSTON, TEXAS
DATE: 08/03/01
TIME: 05:20:33

METER NAME: METER RUN #1

CONFIGURATION DATA

Contract Hour	08:00	Spec. Gravity	0.6	Mole % CO2	0.0
Mole % N2	0.0	Energy Content	1000.0	Pipe Diameter	1.987
Orifice Bore	0.375	Tap Config.	Flange	Tap Location	Downstream
Temperature Base	60.0	Pressure Base	14.65	Atmos. Pressure	14.7
Low DP Cut-Off	0.5	Fpv Method	AGA8 Gross	2530 Method	2530-1992
Fwv Method	Manual	Fwv Factor	1.0	Water Content	1.0
Well Stream	Enabled	Well Stream Val.	1.0		

DATE	TIME	VOLUME MSCF	ENERGY MMBTU	AVG SQRT (DP * AP)	AVG. DP IN H20	AVG. P PSIG	AVG. T DEG. F
07/17/01	08:00	0.1699	0.1699	9.18453	1.31	51.6	1.89
07/17/01	08:30	0.1874	0.1874	9.71828	1.47	51.46	1.86
07/17/01	09:00	0.1871	0.1871	9.68400	1.46	51.3	1.84
07/17/01	09:30	0.1874	0.1874	9.68333	1.47	51.02	1.79
07/17/01	10:00	0.2043	0.2043	10.45441	1.73	50.06	1.62
07/17/01	10:30	0.1855	0.1855	9.60922	1.49	49.5	1.51
07/17/01	11:00	0.1714	0.1714	9.05914	1.32	49.46	1.5
07/17/01	11:30	0.1781	0.1781	9.23295	1.36	49.73	1.54
07/17/01	12:00	0.1902	0.1902	9.81453	1.53	50.06	1.59
07/17/01	12:30	0.1855	0.1855	9.48633	1.43	50.07	1.58
07/17/01	13:00	0.1693	0.1693	9.09532	1.32	50.15	1.6
07/17/01	13:30	0.1245	0.1245	8.77455	1.22	50.9	1.73
07/17/01	14:00	0.1014	0.1014	7.63768	0.87	53.57	2.2
07/17/01	14:30	0.2102	0.2102	10.66151	1.69	54.2	2.32

4.8 The "Data Logger" programming is being further addressed to provide more application to project needs.

4.10 Software and formatting components were reviewed and modified to meet project data needs. Additional considerations for future use include transducer outputs and event indicators (surface arrival and departure of the fluid pump) are being considered for incorporation in the status reports.

5.0 EVALUATION OF PERFORMANCE

5.1 Well # 52 tool installation took place in March of 2002 with, testing in March, April, May, June and July of 2002. Gas gathering system pressure back up / increases in sales line backpressure were coincident with tool installation in March of 2002 and made initial tool runs and data interpretation awkward. Sales line compressor shut down [s] and service work effectively "pressured out" the tool from running for the first several weeks of operation and testing. During this period line pressures measured at 65 to 70 psi. Well head shut in pressure for LRI # 52 during this same period measured as low as 85 psi. In general a 12-psi pressure differential between well and sales line is required to operate the tool. Tool runs during this period were sporadic and variable in terms of fluid production and post tool run gas production. Fluids production with tool runs varied from 0 [zero] to 0.33 Bbls per run. Gas production for the period varied from a high of 14. 7 mcf/d to a low of 7 mcf/d. At the maximum value the gas production and fluid production were similar to the predecessor BEDCO tool and much higher [>60%] than the standard casing plunger used in this well in 2000 and previous years. At the low production of 7 mcf/d the tool and well were producing on average 1 mcf/d less than the average production achieved by the standard casing plunger. All yields were greater than production historically achieved using tubing alone.

5.2 Observations of prototype tool runs, brine production and gas production from well # 52 during this period of unusually unstable line pressures over several months indicated a general decline in fluid production and decrease in gas production post each tool run. In all two different tools [the second tool at BEDCO cost and expense, as it was not budgeted for in the SWC work plan] were subject to in well/ in field-testing. Both evidenced a similar pattern of performance in well # 52. As such, this portion of the test was reluctantly terminated in early August of 2002 and the tools were returned to BEDCO facility for preliminary evaluation. Physical observations of the prototype tool valve assembly indicated a misalignment of the valve and valve seat. This mis-alignment appeared to stem from the size reduction efforts, which removed certain valve stem guides. This misalignment alone did not preclude tool operations when bench tested both pre and post well installation and operations. The second more profound discovery of ex-situ well, in laboratory, testing was the appearance of slow pressure loss from the actuator assembly. This pressure loss was observed to occur over a period of hours to days on the tools used and retrieved from well # 52. As the actuator is a sealed system, the immediate source of the leakage/ failure was not readily apparent. The actuators were returned to the manufacturer for destructive analysis testing. Upon arrival at the manufacturer, the actuators were first re-subjected to a water bath pressure test to confirm absence of integrity as found in the BEDCO facility. Confirmation of pressure leakage from the assembly was made. The actuators were subsequently disassembled and examined under high magnification. This examination revealed corrosion holes in the actuator. The location of the corrosion holes were located on the stainless steel side of a Hastelloy- stainless weld line. Both tool actuators showed a similar failure pattern. Research into the problem shows an elevated corrosion index potential between Hastelloy and stainless steel metals. This corrosive potential in the construction of the actuator was compounded by the welding of the stainless steel to the Hastelloy and certain physical restrictions in the fluid passage through the actuator which caused brine [15 – 20 % NaCl] to accumulate adjacent to the welds where the corrosion effects were concentrated.

5.3 Tool design modifications have been made. These modifications include a support mechanism for the valve and valve seat assembly, which will improve alignment and increase concentricity of valve and seat in the tool. This should further reduce potential for seating problems or leakage of the valve once closed and sealed. The more important remedy is a metallurgy change in the contact area [reduce corrosive index potential] between the stainless steel end fitting and the Hastelloy actuator. This metallurgy change has been coupled with a physical modification to the actuator which eliminates blind passages in the tool, which can trap brine and there by concentrate their corrosive effects. BEDCO has self-funded these design modifications and manufacturing of new actuators outside of the SWC sponsorship on the project. Delivery of the new actuators, lab and field-testing are targeted for November 2002.

5.4 Post the determination of the prototype [smaller tool] actuator under performance in August of 2002, BEDCO re-installed a predecessor larger tool in well # 52 to confirm applicability of the technology. This earlier version, larger, somewhat more cumbersome, tool was deployed in late August of 2002. The tool was set with an increased actuator pressure to accommodate accumulated brine not removed during the previous testing. The tool target was to retrieve 0.75+ Bbl of brine on each tool run. Observations during the month of September 2002 showed 5 to 7 tool runs per week yielding 0.75 to 1.0 Bbl of brine per trip. Gas yield after each of the trips has averaged 17.5 mcf/d. The brine production is ~ 2 fold greater than during previous tool test and gas yields ~ 15 to 20% greater. Comments by the well tender post the old tool re-deployment were, "gee that well just gets better and better". Similar results were achieved during the first 3 weeks of October 2002.

5.5 Qualitative evaluation and limited comparison of conventional brine removal techniques commonly deployed in similar wells to the chosen test well is given below as a compilation of information in an anecdotal format developed from interviews with well operators.

Existing methods for brine removal in area Medina Fm. wells more commonly include:

[Note: These methods are common to other Geologic Fm. and wells]

- Periodic swabbing with a "work over" rig to remove accumulated brines and temporarily restore gas flow, requiring a normal two man complement, appropriate swabbing tools, equipment and investment of several hours total time for a 3000 to 4000' well.
- Installation of casing swabs that operate by dropping of the mechanical operated casing swab to a preset stand. When the tool strikes the stand it mechanically closes a valve regardless of the height of column of fluid atop the tool and regardless of the pressure below the tool to lift fluid column and tool weight to the surface. These types of tools normally require manual release and often man assisted recovery.
- Installation of smaller diameter tubing in 4 to 6 inch wells [commonly 1.5 to 2.5" internal diameter tubing] targeted to allow older production gas wells with declining volume and reducing pressure to lift accumulating fluid from the well to the surface via capillary action in the smaller tubing. This technical approach is often employed with the periodic shut in of the well to increase down hole pressure to a level sufficiently high that upon reopening of the well will purge the tubing of the brine/ fluid column. This method also often employs the use of surfactants "soap sticks" to disperse the brine into a foam and "lighten" the fluid column for purging to the surface, the process unit and the brine tank.

- Tubing rabbits are another technology deployed to produce gas from these types of stripper wells via the periodic purging of fluids from the tubing column. The rabbits are in general a smaller version of the mechanical swab tools with similar associated challenges of mechanical and man-assisted operation.

All these above technology assisted improvements for fluid removal have a common need for manpower assistance and or some add on well external pressure or electronic activated semi-automated controller. Dropping and retrieval of tools [casing swabs and rabbits] involve the need for periodic service [release and retrieval] by a well tender, down time on the well production and or some external assistance such as mechanical or electric timers for dropping of tools. Periodic swabbing by a work over rig is the most labor intensive and least cost effective of all methods. Tubing and soaping to lift fluids similarly results in well production down time during periods of well shut in to build pressure to purge the well and also require appropriate manpower.

Interviews with well tenders and operators alike when questioned, what dictates the frequency of servicing a well where one or the other of the above technology is deployed? Most record a common refrain, "When there is sufficient time to get to it [the well]". As such production is highly dependent upon the frequency of service by the operator and punctuated by periods of non-production and spike production.

One such interview on frequency of service and method of operation with a well tender of more than 30 years experience focused on his experience with the most comparable [albeit not operationally comparable to the design and preliminary operational results of the G.O.A.L. PetroPump] technologies of casing swabs/ mechanical swabs/ 'dumb swabs. Questions posed to operator were simply when and how do you decide to deploy or "Drop" a mechanical swab tool and what do you do if problems arise with it cycling/ returning to the surface with brine:

- The candid response was, as a conscientious operator he tries to inspect the well every two days and make a qualitative determination of well production and wellhead pressure. At such time as he determines from his inspection and interpretation of the process unit analogue volume/ flow production chart, pressure reading at the process unit and possibly a well head pressure reading that production and pressure are not acceptable [i.e. gas flow volume down and pressure down based upon qualitative assessment], the mechanical swab tool is physically released from the catcher to the well.
- The well is then next inspected one or two days in the future. The inferred reasoning on this lapse in time frame is that the tender has previous empirical experience indicating that is the approximate time it takes for the tool to make a 'run' [i.e. return to the surface with fluid] in that the mechanical tool must drop completely through the accumulated fluid column to the well stand to set the tool/ close the mechanical valve before it can initiate a run. This presupposes that the fluid column is sufficiently short and the behind mechanical tool pressure sufficiently great to lift both mechanical tool and column of fluid to the surface for processing.
- If/ when the mechanical swab tool does not return to the surface the base interpretation and common empirical experience indicates that this is due to the fact that the pressure behind the tool is insufficient to lift tool and fluid column atop the tool.

- Follow up actions to retrieve a stalled mechanical swab tool can vary and usually evolve from the simplest response of "shutting in" the well to build down hole pressure for 0.5 to 1.0 day [s] with subsequent release of the pressure rapidly directly to the brine tank. More involved and evolved actions can include the addition of a surfactant, shut in of well to build pressure and subsequent purge to brine tank to the more complex action of tool retrieval techniques using other mechanical equipment and tools.
- This non regular purging of the well of the fluids and often long periods of low to no gas flow resultant from stalled mechanical swab tools is referenced to periodically lead to down stream effects such as winter icing of the process unit further reducing gas output from the well.
- The well tenders' summary of operation of wells with mechanical casing swabs is that it tends to produce gas from the well in an uneven and punctuated manner. There are further frequent periods of well down time leading to less overall gas production than the well is capable of were the brine uniformly and regularly removed.

5.3 Project Schedule

Task Performed	[2001] Months [2002] [06/01]-07-08-09-10-11-12-[01/02]-04-06-08-10
Design Tool	>>>>>>>xxxxx C
Construct Prototype	>>>>>>xxxxxxxxxxxxxx C
Select Candidate Well [test]	>>>>>xxxxxxxxxxxxxxxxxC
Bench Test Tool	>----------xxxxxxxxxC
Test Well Production	>>>>>>>>>xxxxxxxxxxxxC
Evaluation of Performance	>>>>>>>>>>>xxxxxxC
Evaluate/ Estimate/ Recommend	>>>>xxxxxxC

Key: >>>> -Original scheduled time frame
xxxx -Revised time frame to complete
C -Completed task

6.0 EVALUATE ECONOMICS

6.1 Potential economic payback from the use of the GOAL PetroPump is estimated below from results of predecessor tool production increases in the LRI # 52 well. This data used in the base calculations was derived from operations in 2001 and early 2002. As noted above in section 5.4, redeployment of the predecessor tool in well # 52 has improved production in the month of September and October 2002 to an average of 17.5 mcf/d. As such all values noted below for payback and increases of production could be projected to improve by 15 to 20%.

6.2 Estimates of Payback from Production

Assumptions: * "Tool" Cost and Well Modifications @ $8950.00
* LRI # 52 Monthly Average Production with Tubing @ 98 mcf
* LRI # 52 Monthly Average Production with 'casing plunger' @ 252 mcf
* Value of gas @ $3.00 mcf

Table 6-2

Ave. Prod. using GOAL Pump	Ave. Prod. using tubing in 1995	Average Prod. Using 'casing plunger'	Payback @ $3 mcf vs tubing production	Payback @ $3 mcf vs 'casing plunger production
381 mcf [5 mo.]	98 mcf	252 mcf	~10 months	~25 months

Note: Average production for September and October of 2002 for this well using the GOAL PetroPump were averaging 17.5mcf/d or ~ 500 mcf/ month

It must be noted that the yields of the well tested is very small [~3 mcf/day of gas via tubing at initiation of test] in comparison to the average gas stripper well in the US @ 15 mcf/ day. These wells, even with the improvements yielded by the G.O.A.L Petropump are at or below the average US gas stripper well production. Application of the Tool in wells with greater production potential [i.e. the average stripper well] which have need for regular automatic brine [fluids] removal should yield better results and quicker payback on capital invested in the tool. The current cost of the Tool at approximately $9000 complete with wellhead modifications for installation is elevated. This is due to proprietary construction materials and techniques. Production of Tool in a commercial manner should reduce cost and payback on capital investment for the Tool user. Finally the uniqueness of the G.O.A.L PetroPump and its on Tool self-actuating controls to regulated frequency and volume of fluid removal from wells differs greatly from casing plungers producing superior results in these test and has its own unique market niche.

6.3 Cost Comparisons to Other Alternatives

Cost comparison of the G.O.A.L. PetroPump to the common used equipment for fluid removal from gas wells in the depth range of 3000' to 6000' would include:

- Pump Jack/ Beam Lift, associated sucker rod, tubing and down hole pump can have capital cost in the range of $10,000 - $40,000. Operating cost for pump jacks range from $2000 to $10,000/ year depending on volume and type of fluids produced, maintenance, replacement parts and service required.

- Tubing string production could have $8,500 to $15,000 capital cost dependant on tubing diameter and operating cost ranging in the $1500- $3000/ year for manpower & surfactants.

- Casing plungers' capital cost with the necessary well head modifications to receive the unit are in the range of $3500 to $5000 capital. Additional capital cost for well head controllers for any attempt at automation of casing plungers is also needed [as opposed to man assisted runs], at $1000 to $5000. Operating cost would include manpower at a minimum of $500 to $1000/ year to $2000- $3000/ year on manual run tools. Work over cost to retrieve drowned and or stuck tools are not herein quantified but typical rig/ day cost are $750- $1000.

- Tubing plungers [Rabbits] base requirements include the installation of a tubing string at $8,500 to $15,000 as noted above plus the capital cost of a Tubing plunger at $2000 without any automation to $6000 with automation [semi] controls. Operating cost are not dissimilar to casing plungers noted above at $1000 to $3000.

Further with respect to casing plungers and tubing plungers, they do not operate in the same or similar fashion to the G.O.A.L. PetroPump with on Tool controls and down hole/ up hole smart Tool technology.

In terms of applicability of this G.O.A.L. Tool to wells in the test area of New York State. It was determined that approximately 3,523 gas wells and approximately 529 active oil wells exist in Chatauqua County, New York. Based upon our exposure to the wells in the area it is likely that 50% or more of these wells will have fluid production related problems in the life of the wells. It is further likely they will require some form of tool related technology to produce gas and or oil. Assuming the G.O.A.L. PetroPump Tool would serve 1/3 of the wells in need of tools for enhanced production some 500 to 600 wells would be candidates for the GOAL tool in Chatauqua County. Projecting those numbers to the entire state of New York production could mean more than 1500 tools for state of New York wells.
Assuming only an 8-mcf/d increase per well [in range of test increases] at $3/ mcf could yield $13,000,000 in gas value and a pay back on 1500 tools at $9000/ tool in a one year time period

6.1 Over the recent years several organizations have begun to evaluate the number of stripper gas and oil wells in the United States which exist and are troubled by water production. BEDCO's preliminary review of the number of wells for which the technology being developed may be applicable is derived from several sources. Those specifically referenced here in are:

  - National Survey – Marginal Oil and Gas Report by IOGCC [Annual]
  - Ohio and West Virginia Survey – University of Kentucky by E. Choong
  - New York – IOGANY Marginal Well Study sponsored by NYSERDA 2000

6.3 Details of these survey and more specific analysis will be developed and presented in the final report post in field testing of the tool. A GRI study by Spears indicates > 200,000 stripper wells in North America producing < 25 barrels of fluid/ day. Our preliminary analysis conservatively estimates applicability for the technology too more than 50,000 water producing gas stripper wells in the US. Potential applicability for application to stripper oil wells should be evaluated by separate analysis and testing, however a very conservative estimate could be made at 40,000 oil stripper wells.

CONCLUSION

The need for and applicability of a Gas Operated Automated Lift PetroPump [A Smart Swab Tool] for removal of fluids from stripper wells remains a sound goal and desirable tool for the oil and gas wells of America and the world. Key elements of such a tool are abilities to work in varying geologic environments of pressure, depth, fluid production, in well chemistry and operating conditions. Current target wells require the tool to be readily deployable and serviceable in 4" ID wells with but minor structural changes to the well head and process units to be economically viable.

Future needs of such a Gas Operated Automated [lift] Tool will target wells with 2.5" diameter tubing and or open hole/ large diameter completion wells or open hole completions that are readily retrofit with isolation packers and continuous smaller diameter tubing than the nominal open hole diameter of 6.25".

Bench and test stand testing of varying automated valve closure assemblies and engineering calculations indicate potential operating ranges for the prototype tool at 50 to 600+ [psi] and potential fluid lift of 0.1 to 6_-+ bbl's per tool cycle. Field trials of a prototype tool have confirmed the ability to operate in the lower half of these bench-tested values.

Automated computerized well head data loggers show they can record varying location pressures at the well head and process unit as well as continuous volume of production have evolved to a point to be applicable for in field continuous recording of operating conditions of the prototype tool. This data can serve to act as basis of tool adjustment for optimum performance and to target tool components for upgrade and improvement.

Field trials of this data logger technology on a typical target well have shown both promise of results, need for modification of software formatting and beneficial results of such modifications. These results to date indicate their applicability to meet the needs of quantifying 'real time' the effectiveness and operation of such an automated gas lift tool.

Review of operations records of a regional gas producer [i.e. total yield, current yield and decline curves] in conjunction with precursor [non GOAL PetroPump] tool testing have identified a number wells which can benefit in terms of production increases from use of an automated fluid removal tool. On a national basis tens of thousands of stripper wells appear applicable for use of the technology to improve production. Production increases even if half of the predecessor and prototype tool results can amount to tens of millions of dollars worth of additional recovered energy resources at modest well head re-configuration and G.O.A.L. PetroPump cost which could be recovered with in 1 to 3 years based upon recent prototype tool test results. Tool modifications and improvements can make the tool more durable and better functioning to further increase performance and shorten pay back on capital tool investment.

Appendix 1

Table 1 - 1 Tested Well # 52

Test Period	1996/1997	2001/2002
Completion date	11-1-83	11-1-83
Formation	Medina [Grimsby/ Whirlpool]	Medina [Grimsby/ Whirlpool]
Geology	Sandstone [tight]	Sandstone [tight]
Total Depth	3,343 feet	3,343 feet
Perforations	3,127 – 3,229 feet	3,127 – 3,229 feet
Casing size	4.5"	4.5"
Production prior to test	3 mcf/d via tubing	8mcf/d w/ casing plngr. tool
Well head pressure	320 c/ 60 t psig	180 psig
Line pressure [sales]	60 psig	55 psig
Bottom Hole Temperature	97 deg. F	-----

Table 1 – 2 Candidate Test Well # 29

Test Period	2002
Completion Date	1982
Formation	Medina [Grimsby/ Whirlpool]
Geology	Sandstone [tight]
Total Depth	2390
Perforations	2299 – 2370
Casing size	4.5"
Production prior to test	~9 mcfd w/ std. casing plunger tool
Well head pressure	150 psi
Line pressure [sales]	Variable 25 to 45 psi
Bottom Hole temperature	?

Appendix 2

Attachment C in Original Proposal with Noted Modifications to Reflect Actual Expenditures by BEDCO

	Requested & Received from SWC	Proposed Cost Share by BEDCO	Expended Cost Share by BEDCO
Salaries and Wages	$16,790--	$35,143--	$155.518--
Fringe Benefits	--	--	--
Materials and Supplies	$4,700--	--	--
Equipment	$14,600--	--	--
Travel	$4,220--	$2,170--	$2170--
Publication/ Information Dissemination	--	$2,500--	$2,500--
Other direct Cost [Misc.	--	$3,250--	$3,250--
Prototype tools/ spares and modifications	$12,500-	--	--
Work over Rid/ Fitters	$5,990--	--	--
Facilities and Administration	$1,200--	$5,760--	$5,760--
Totals	$60,000-	$47,653— [44.5%]	$155,518— [73.6%]

Note: Total combined expenditures by SWC and BEDCO on the project are $215,518.00