Title Page

Report Title: Low Cost Methodologies to Analyze and Correct Abnormal Production Decline In Stripper Gas Wells

Type of Report: Quarterly Technical Progress Report

Reporting Period Start Date: 04/01/2001

Reporting Period End Date: 06/30/2001

Principal Authors: Jerry James, Gene Huck, and Tim Knobloch

Date Report was issued: July 2001

DOE Award Number: DE-FG26-99FT40699

Name and Address of Submitting Organization: James Engineering, Inc.
231 Third Street
Marietta, Ohio 45750

Disclaimer

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trade mark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Abstract

The goal of this research program is to develop and deliver a procedure guide of low cost methodologies to analyze and correct problems with stripper wells experiencing abnormal production declines.

A study group of wells will provide data to determine the historic frequency of the problem of abnormal production declines in stripper gas wells and the historic frequency of the causes of the production problems. Once the most frequently occurring causes of the production problems are determined, data collection forms and decision trees will be designed to cost-effectively diagnose these problems and suggest corrective action. Finally, economic techniques to solve the most frequently occurring problems will be researched and implemented. These systematic methodologies and techniques will increase the efficiency of problem assessment and implementation of solutions for stripper gas wells.

This seventh quarterly technical progress report further describes the data reduction and methodology to develop diagnostic tools to evaluate the cause of declines in problem wells, specifically addressing the methodology to analyze the group of wells where recent problems have occurred utilizing the data gathering forms. This report also describes the methodology to select the two wells with the greatest potential for increase and also having the most frequently occurring problem. Finally, this report describes the preliminary results of the remediation applied to the two wells selected.

Two wells selected and analyzed from a twenty-four well study group indicated that their current abnormal production decline was attributable to fluid build-up in the wellbore. Subsequent remediation work of putting both wells on pump to reduce fluid build-up in the well bore decreased the flowing bottom hole pressure and increased gas production dramatically.

A procedure guide and summary report that will also evaluate the results of the methodology and implemented procedures will be completed by August 31, 2001.

Table of Contents

List of Graphical Materials.....1

Introduction.....2

Executive Summary.....3

Experimental.....4

Results and Discussion.....5

Conclusion.....15

References.....16

Bibliography.....16

List of Acronyms and Abbreviations.....16

Appendices.....16

List of Graphical Materials

Appendix 1	Decision Tree: Triage Form for Abnormal Production Decline Review
Appendix 2	Tubing Plunger Data Collection Form
Appendix 3	Casing Plunger Data Collection Form
Appendix 4	Pumping Unit Data Collection Form
Appendix 5	Swab or Flow Well Data Collection Form
Appendix 6	Study Group Analysis Summary
Appendix 7	Vogel Inflow Performance Relationship Chart

Introduction

The goal of this research program is to develop and deliver a procedure guide of low cost methodologies to analyze and correct problems with stripper wells experiencing abnormal production declines.

A study group of wells will provide data to determine the historic frequency of the problem of abnormal production declines in stripper gas wells and the historic frequency of the causes of the production problems. Once the most frequently occurring causes of the production problems are determined, data collection forms and decision trees will be designed to cost-effectively diagnose these problems and suggest corrective action. Finally, economic techniques to solve the most frequently occurring problems will be researched and implemented. These systematic methodologies and techniques will increase the efficiency of problem assessment and implementation of solutions for stripper gas wells.

This seventh quarterly technical progress report further describes the data reduction and methodology to develop diagnostic tools to evaluate the cause of declines in problem wells, specifically addressing the methodology to analyze the group of wells where recent problems have occurred utilizing the data gathering forms. This report further describes the methodology to select the two wells with the greatest potential for increase and also having the most frequently occurring problem.

Two wells selected from a twenty-four well study group that indicated that their current abnormal production decline was attributable to fluid build-up in the wellbore. Subsequent remediation work of putting both wells on pump to reduce fluid build-up in the wellbore decreased the flowing bottom hole pressure and increased gas production dramatically.

A procedure guide and summary report that will also evaluate the results of the methodology and the implemented procedures will be completed by August 31, 2001.

Executive Summary

The goal of this research program is to develop and deliver a procedure guide of low-cost methodologies to analyze and correct problems with stripper wells experiencing abnormal production declines.

A study group of wells will provide data to determine the historic frequency of the problem of abnormal production declines in stripper gas wells and the historic frequency of the causes of the production problems. Once the most frequently occurring causes of the production problems are determined, data collection forms and decision trees will be designed to cost-effectively diagnose these problems and suggest corrective action. Finally, economic techniques to solve the most frequently occurring problems will be researched and implemented. These systematic methodologies and techniques will increase the efficiency of problem assessment and implementation of solutions for stripper gas wells.

This seventh quarterly technical progress report describes the data reduction and methodology to develop diagnostic tools to evaluate the cause of declines in problem wells, specifically addressing the methodology to analyze a group of wells where recent problems have occurred utilizing the data gathering forms. This report further describes the methodology to select the two wells with the greatest potential for increase and also having the most frequently occurring problem.

A twenty-four well study group that was experiencing abnormal production decline were reviewed utilizing the previously developed Decision Tree Triage Form and Data Collection Forms. Analysis of the study group showed that 58% of the wells experienced Fluid Accumulation Problems, 29% experienced Mechanical Failure, while 13% experienced Gathering System Restriction.

Two wells selected from the twenty-four well study group that indicated that their current abnormal production decline was attributable to fluid accumulation problems. Fluid accumulation was found to be the most frequently occurring problem, 46%, in the initial study group of 270 wells.

The C. Williams # 1 and the Lucille Richey #1 were selected from the study group of twenty-four wells. These two wells showed the greatest opportunity for improvement based upon Decision Tree Triage Form and Data Collection Form completion and analysis. Subsequent to the remediation work of putting both wells on pump to reduce fluid buildup in the wellbore decreased the flowing bottom hole pressure and increased gas production dramatically.

A procedure guide and summary report that will also evaluate the results of the methodology and the implemented procedures will be completed by August 31, 2001.

Experimental

No experimental methods, materials, or equipment were used in this phase of the research.

Results and Discussion

This report addresses the following tasks:

1. Apply Methodology to a Group of Wells Where Recent Problems Have Developed
2. Select the Two Wells with the Greatest Potential for Increase and also having the Most Frequently Occurring Problem

Each task identified above will be reviewed in detail and the methodology utilized described.

Task 1 – Apply Methodology to a Group of Wells Where Recent Problems Have Developed

“From the study group, select a number of wells with recent abnormal declines. Evaluate the cause of the decline using the methodology and the diagnostic tools developed, and evaluate the potential for increase. Using the estimated cost, evaluate the group to select the most economical candidates. Remediation strategies may include equipment changes, well-bore clean-out, line pressure restriction reductions, and reservoir stimulation.”

Based upon further analysis and the definition for abnormal well production, i.e., three months of consecutive production less than 50% of forecasted production, twenty-five wells were identified from decline curve analysis as having recent abnormal production declines. The following wells were reviewed utilizing the Decision Tree Triage Forms and the Data Collection Forms to analyze the potential source of the abnormal well decline.

Lease Name	County	Township	Well Type
1. E. Carrick #1	Noble	Brookfield	TPL
2. R. Florence #1	Washington	Salem	TPL
3. R. Krapps #1	Noble	Jackson	TPL
4. M. Pickenpaugh #3	Noble	Sharon	TPL
5. OP Combs #4B	Noble	Brookfield	TPL
6. Reed #1	Noble	Jackson	SWB
7. W. Fitzgerald #1	Guernsey	Westland	TPL
8. R. McCall #1	Muskingum	Highland	TPL
9. R. Krapps #2	Noble	Jackson	TPL
10. A. Larrick #1	Noble	Brookfield	SWB
11. Richey Dunkle #1	Morgan	Bristol	SWB
12. Richey Lucille #1	Morgan	Bristol	SWB
13. JB Bigley #1	Morgan	Manchester	SWB
14. Dee D. Dunkle #1	Morgan	Bristol	SWB
15. Richey Reed #1	Morgan	Bristol	SWB
16. OP Chritopher #26C	Guernsey	Spencer	TPL
17. Owen Reed #1	Morgan	Manchester	TPL
18. C. Williams #1	Morgan	Bristol	TPL
19. Presdee #1	Guernsey	Adams	TPL
20. M. Pickenpaugh #4	Noble	Sharon	TPL
21. John Jenkins #1	Noble	Noble	TPL
22. Ellis Miller #3	Morgan	Bristol	TPL
23. OP Brown #15B	Muskingum	Meigs	TPL
24. L. Stephenson #2	Coshocton	Adams	TPL

The following methodology was used to analyze the twenty-four well study group of wells identified as experiencing abnormal production decline as follows:

1. Complete the Decision Tree Triage Form that provides a methodology to lead the operator to the most appropriate solution.
2. Complete the Data Collection Form for the specific well type that when fully completed provides the necessary data for well analysis.
3. Apply a type decline curve to the complete production history.
4. Review or prepare a chronology of the workover history.
5. Review weekly pumper sheets for detailed fluid production history.
6. Determine the maximum obtainable production rate by decline curve analysis and/or Vogel Inflow Performance Curve Analysis.
7. Analyze all data, prepare recommendation, and estimate cost and benefit of remediation.

The Decision Tree Triage Form

The Decision Tree Triage Form, Appendix 1, provides a methodology of analysis for the production manager to evaluate the cause of abnormal production declines in stripper gas wells.

After completing the sections for date of analysis, lease name, well identification number, and artificial lift mechanism or fluid removal technology, the production manager completes Phase 1 to further identify the problem well.

Decision Tree Triage Form - Phase 1, Identify the Problem Well

Step one of Phase 1 identified how the problem well with abnormal production decline was identified. This was typically a result of a phone call when it happened, the weekly pumper meetings, or the monthly “Priority” production variance report prepared by the production manager that compared actual production to forecasted production.

Step two of Phase 1 reviewed the production decline curve and forecast to ensure that they appropriate and complete. Should the wrong production data or invalid decline forecast be applied to a production history, the “Priority” production variance report would then be incorrect. A type production decline curve was then applied to the production history for comparison purposes that identified periods of low production and specific times when production began to deviate from ideal production.

It is important to note that the complete production history of the well is invaluable. Reviewing only a portion of the well's production history often leads to invalid conclusions. Further, while gas production volumes are typically reported on a monthly basis, oil production volumes were typically only recorded when the oil was sold. It was also found that the water production histories were incomplete. All fluid production volumes are important when analyzing stripper gas wells and should always be recorded in a summary format for future reference.

Step three of Phase 1 verified the problem still existed either by talking directly to the pumper and/or reviewing the most recent weekly pumper reports. Pumper interaction is extremely important to the success of stripper gas well operation.

Step 4 of Phase 1 checked for metering inaccuracy that was completed by comparison to master meters or to review the gas chart integration statements as compared to the actual gas chart. An example could be an orifice plate change that was not changed by the chart integration company resulting in invalid chart integration.

Step 5 of Phase 1 checked for the integrity of the gas gathering system by pressuring up on the system, if necessary.

The completion of Phase 1 ensures that the problem still exists and was not a reporting or data entry error before proceeding to further analysis. The nature of stripper gas wells requires that minimum effort be expended for maximum benefit.

Decision Tree Triage Form - Phase 2, Measure the Problem

The second phase of this Decision Tree Triage Form analysis begins to gather data to allow the production manager to solve the problem of abnormal production decline.

Step 6 of Phase 2 was to issue the appropriate Data Collection Form to the respective pumper. Data Collection Forms, Appendices 2 – 5, were developed for casing plunger wells, tubing plunger wells, swab or flow wells, and pumping wells. Due to the specific nature of each fluid removal technology, information applicable to each technology was requested. Sections I, II, and III were for the field personnel to complete, while sections IV, V, VI, and VII were for the production manager to complete.

In section I of the Data Collection Form, the pumper would identify the producing formation, beginning and ending cycle surface pressure information, previous cycle information, domestic gas usage, the gas system operating pressure, and if additional wells the produce into the same gas gathering system.

It should be noted that domestic gas usage has been found to severely affect stripper gas well production since domestic gas is often supplied from the production casing to tubing annulus. This creates a pressure drop to casing side depleting storage volume and allowing fluid to build-up in the annular area instead of to the tubing.

The recording of pressure information, like fluid production information, is often neglected. All well shut-in pressures as well as the length of time shut in should be recorded in a summary format. It is recommended that if a well is not shut-in due to maintenance, then the well should be shut-in at least once per year, or at a minimum, once every two years. The pumper should also be aware of the last shut-in pressure for the well.

In section II of the Data Collection Form the pumper would specify the current production rates for the oil, gas, and water. These rates may be either by the week or by the day depending on the pumper's or company's preference. We also reviewed and summarized the past six months of pumper's reports to determine the weekly tank gauges for fluid production, and pumper's estimates of gas production.

In section III of the Data Collection Form, space was provided for the pumpers to note their comments regarding the current or future status of the well. The comments could state the reason for the mechanical failure, the location and volume of domestic gas usage or their insight as to the root problem.

The Data Collection Form was then returned within a relatively short period of time, typically one week, to the production manager at the next week's pumper's meeting. Sections IV-VII were for the production manager to complete.

Section IV of the Data Collection Form identifies the perforation intervals, and the size and depth of the tubulars in the well. In addition, the flowing bottom hole pressure and the shut in bottom hole pressure were reported if available. While most of the data necessary for the analysis of abnormal production may not seem extensive, it is often not immediately available and may have to be pursued.

Section V of the Data Collection Form is for the Vogel Chart analysis, see Appendix 7, to determine the well's productive potential. The ratio of the flowing bottom pressure to the shut in bottom hole pressure is entered on the y-axis, across to the intersection of the chart, then down to the x-axis. The x-axis provides the percentage of maximum production. For example, a well with a flowing bottom pressure of 100 psi and a shut in bottom hole pressure of 300 psi has a ratio of 0.333, and therefore producing at 83% of its maximum rate. The same well producing at 10 mcf/d has a maximum producing rate of 12 mcf/d, 10 mcf/d divided by 0.83, if the flowing bottom hole pressure was reduced to 0 psi.

Section VI of the Data Collection Form is for the forecasted rates of production based upon the lowest flowing bottom pressure the production manager determines is obtainable.

Section VII of the Data Collection Form is for data regarding the last well work. While the last well work is helpful to determine the next course of action, we also completed a

chronology of the well work performed from completion to the present. The chronology proved very valuable in the analysis of abnormal production decline. All fluid and pressure data were noted as part of the chronological record including beginning and ending fluid levels when swabbing, total and type of fluid swabbed, shut in pressures, casing and tubing pressures, test volumes, and equipment modifications.

Section VIII of the Data Collection Form is for the production manager to note their thoughts as well their recommendation for the future production of the well. A section is also provided for the proposed cost of the workover or repair. We have observed that payout is often a good indicator of the economic viability of a project.

Steps 7 and 8 of Decision Tree Triage Form - Phase 2 check for changes in the sales line pressure and fluid production respectively.

Decision Tree Triage Form - Phase 3, Solve the Problem

Based upon the information provided in Phase 2, the production manager can then evaluate what additional information may be required or equipment change may be necessary to optimize production from the stripper gas well.

From the current production data, the current flowing bottom hole pressure, and the most recent shut in bottom hole pressure, the production manager can determine the maximum productive rate for the well and whether the well is producing at an optimum production rate.

If the well is not producing at the optimum rate, then it will be necessary to determine whether the current form of production is sufficient, if modifications in the current production can be made, if production equipment changes are required, or if additional compression would be required.

The well may also need to be shut in for bottom hole pressure analysis, or may be necessary to shut in, or sell, or plug and abandon the well.

Each well in the twenty-four study group was analyzed utilizing the aforementioned methodology. A preliminary summary of the analysis performed utilizing the Decision Tree Triage Forms and the Data Collection Forms is included in Appendix 6.

The C. Williams #1 and the Lucille Richey #1 indicated to have the greatest potential for production increase and to be experiencing the most commonly occurring problem, fluid accumulation.

Task 2 - Select the Two Wells with the Greatest Potential for Increase and also having the Most Frequently Occurring Problem

“Use these two wells for the field demonstration portion of the project and install whatever equipment has been determined most efficient for the problem identified. Perform recommended procedures, then monitor the effectiveness of the enhancement program for a minimum of two months and adjust as necessary.”

The following discusses the analysis of the C. Williams #1 and the Richey Lucille #1 that were selected as the two wells with the greatest potential for production increase and also had the most frequently occurring problem, fluid accumulation. Further, the remediation strategy and the preliminary effectiveness of the enhancement program will also be discussed.

C. Williams #1

The C. Williams #1 is a Clinton formation well that at the time of analysis was being produced through 1 ½” tubing as a tubing plunger well. Abnormal production decline had been identified from Artex Oil Company’s monthly “Priority” reports.

A Decision Tree Triage Form was prepared for the well. In the Phase 1 review of the well it was found that the production decline data and associated forecast were reviewed and found correct. Further, the pumper indicated that the problem still existed.

The metering system for the C. Williams #1 however, was somewhat complicated. The C. Williams #1 and #2 were fed together with a third well through a common master meter. The third well had its own meter and gas sales from the master were first allocated to the well with its own meter then the remainder was allocated between the Williams #1 and #2.

Both the C. Williams #1 and #2 had separate meters up through 1994, therefore a good production history and established decline curves for both wells were available. The C. Williams #1 well had historically been the better of the two wells. However, a review of the casing and tubing pressures indicated that the C. Williams #2 and the third well were still producing as before, however, the C. Williams #1 was not. Further, the gas system did not indicate any unusual integrity problems at the time of analysis.

In the Phase 2 Triage analysis, a Tubing Plunger Data Collection Form was sent to the field for review and completion of sections I, II, and III.

The producing cycles were three cycles per day at 30 minutes on per cycle. That is, the well would produce for 30 minutes, be shut-in for seven hours, produce for 30 minutes, then be shut-in for another seven hours before producing again. The well had beginning and ending tubing pressures of 220 psi and 110 psi respectively, while the beginning and

ending casing pressures were 240 psi and 200 psi respectively while producing into a 35 psi gas gathering system. The pumper had reportedly later unsuccessfully tried to increase production by trying more cycles with less on time to reduce after-flow into the wellbore. Well production for the C. Williams #1 at the time of analysis was estimated to be 6 mcf per day and ½ barrel of water per day.

Continuing with the Phase 2 of the Decision Tree Triage Form analysis, the remainder of the Data Collection Form was completed by the production manager. Based upon a flowing bottom hole pressure of 200 psi and the last reported surface shut in pressure of 320 psi, the well had a FBHP to SIBHP ratio of 0.625. By utilizing Vogel's Inflow Performance Relationship Curve, the C. Williams #1 was estimated to be producing at approximately 55% of its maximum producing rate. Therefore at an estimated current producing rate of 6 mcf/d, the well could have a maximum production rate of 11 mcf/d.

When a typical Clinton Sandstone Decline curve was applied to the historical production data, it indicated that the well had been under produced since the 1990 when the tubing plunger was removed and the well converted to a casing plunger. The well was also shut-in for a period of two years due to area mining activities. Decline curve analysis indicated that the well was capable of at least 10 mcf/d.

The actual production was questionable due to the current metering arrangement, however, early time production history indicated significant production when pressure drop achieved. Pressure information collected through previous service work and this analysis confirmed that very little pressure drop is being achieved with current operations. Since the well was not able to be produced successfully by tubing plunger, casing plunger, or swabbing, the recommended method to effectively reduce the flowing bottom hole pressure was the installation of a bottom hole pump, rods, and pumping unit. Estimated cost for the remediation was \$18,000.

After the installation of the pumping unit, producing at four cycles per week and four hours per cycle, preliminary production results indicate that the well is currently averages 38 mcf/d and 2 barrels of fluid per day, almost four times greater than predicted. The reason for this positive variance is due to the prior metering and allocation of production, with the well now having its own meter into a separate system.

The preliminary results of this well remediation indicate the importance of accurate production data and a complete production history. Further results, including decline curve, will be provided in the final summary report.

An abbreviated chronology of the C. Williams #1 is as follows:

05/18/1973	Total Depth 4750', 4715' of 4 ½" casing
05/15/1973	Twenty perforations from 4,562'-4,672' in the Clinton Sandstone. Fracture stimulated with 100 gallons 15% acid, 1967 barrels of water, and 35,000# of 20/40 sand.

05/18/1973	Initial Absolute open flow 3,800 mcf/d, Initial shut in pressure, 1325 psi
06/08/1973	Producing through 4,694' of 1 ½" tubing into a 250 psi sales line, shut in casing pressure 1000 psi, flowing tubing pressure 825 psi.
07/01/1982	TOH with 1 ½" tubing, plunger in three pieces. Reran tubing.
06/26/1990	Reset tubing at 4,525', left tubing plunger out
1994-1996	Well shut in due to mining activities
08/05/1996	TOH with 1 ½" tubing, clean out well, set casing plunger stand at 4,518', install Concoyle casing plunger.
01/19/1997	Fish Concoyle, fluid level at 3,100', swab 30 barrels fluid
02/15/1997	Fish Concoyle, swab 12 barrels fluid
08/26/1997	Fish Concoyle
01/19/1998	Fish Concoyle
04/24/1998	Fish Concoyle, fish Concoyle stand, swab 15 barrels of fluid. Rerun 4,535' 1 ½" tubing
10/27/1999	Swab 11 barrels fluid, well now produced with tubing plunger
06/08/2001	Blew well down, set 1 ½" seating nipple at 4627', TIH w/ 1 ½" x 1 1/16" x 10' x 13 RHBC bottom hold down pump on 184 5/8" slim hole rods. Set pumping unit and install separate metering. Return to production.

Richey Lucille #1

The Richey Lucille #1 is a Clinton formation well that at the time of analysis was being produced through 4 ½" casing as a swab well. Abnormal production decline had been identified from Artex Oil Company's monthly Priority reports.

A Decision Tree Triage Form was prepared for the well. In a Phase 1 review of the well it was found that the production decline data and associated forecast were reviewed and found correct. Further, the pumper indicated that the problem still existed. The gas system did not indicate any integrity problems at the time of analysis.

In the Phase 2 Decision Tree Triage analysis, a Swab Well Data Collection Form was sent to the field for review and completion of sections I, II, and III.

The Richey Lucille #1 was produced twenty-four hours a day seven days a week. The average flowing casing pressure and associated gas sales line pressure was 40 psi.

Continuing with the Phase 2 Decision Tree Triage Form analysis, the remainder of the Data Collection Form was completed by the production manager. No estimate was available for the flowing bottom hole pressure since the well was a swab well, however, based upon a previous fluid level of 600' noted in service rig report, a shut in bottom hole pressure was estimated to be approximately 230 psi, assuming a 0.9 specific gravity of the fluid. Therefore no Vogel estimate was possible.

When a typical Clinton Sandstone Production Decline curve was applied to the historical production data, it indicated that the well had been under produced since the 1994 when the rods and tubing were pulled and the well converted to a swab well. Production decreased substantially following the removal of rods and tubing. Production decline curve analysis indicated that the well was capable of at 25 to 30 mcf/d, when it was presently producing an average of 8 mcf/d.

The Richey Lucille #1 could not be produced by casing plunger to maintain a minimal fluid level. Further, swabbing in 03/2000 confirmed that fluid was still present in well bore during production. Gas production subsequent to swabbing increased production approximately 20%, but the increase was not sustained. It appeared that a minimal amount of fluid in the wellbore late in the life of a well has dramatic effect on well performance. Therefore, the recommended method to effectively reduce the flowing bottom hole pressure was the installation of a bottom hole pump, rods, and pumping unit. Estimated cost for the remediation was \$18,000.

After the installation of the pumping unit, producing at two cycles per week and four hours per cycle, preliminary production results indicate that the well is currently producing at an average of 26 mcf/d, similar to that predicted by decline curve analysis.

The preliminary results of this well remediation indicate the importance of accurate production data and a complete production history. Further results, including production decline curve, will be provided in the final summary report.

An abbreviated chronology of the Lucille Richey #1 is as follows:

06/15/1974	Total Depth 4800', 4780' of 4 1/2" casing
05/15/1974	Fifteen perforations from 4,668'-4,692' in the Clinton Sandstone. Fracture stimulated with 400 gallons 15% acid, 1800 barrels of water, and 60,000# of 20/40 sand.
08/18/1974	Initial Absolute open flow 2,000 mcf/d, Initial shut in pressure, 1400 psi, 85 day average production 485 mcf/d.
05/29/1985	Put on pump, electric.
05/08/1990	Hot oil job.
11/02/1994	Pulled Rods and Tubing, set Jet Star Casing Plunger stand.
1995-1998	Producing with casing plunger, estimated, plunger pulled.
03/07/2000	Swab 600' fluid.
04/26/2001	Fished casing plunger stand, TIH w/ pump, rods and tubing.

Conclusion

The goal of this research program is to develop and deliver a procedure guide of low cost methodologies to analyze and correct problems with stripper wells experiencing abnormal production declines.

This seventh quarterly technical progress report describes the data reduction and methodology to develop diagnostic tools to evaluate the cause of declines in problem wells, specifically addressing the methodology to analyze the group of wells where recent problems have occurred utilizing the data gathering forms. This report further describes the methodology to select the two wells with the greatest potential for increase and also having the most frequently occurring problem. Finally, this report evaluates the results of the methodology and the implemented procedure.

The analysis of twenty-four well study group that were experiencing abnormal production utilizing the Decision Tree Triage form and the Data Collection Forms again showed that fluid accumulation is the predominant cause of abnormal production decline in stripper gas wells. Analysis of the study group showed that 58% of the wells experienced Fluid Accumulation Problems, 29% experienced Mechanical Failure, while 13% experienced Gathering System Restriction. In the initial study group of 270 wells, 46% of the wells were found to have fluid accumulation as the most frequently occurring problem.

Two wells selected from the twenty-four well study group that indicated that their current abnormal production decline was attributable to fluid build-up in the wellbore. Subsequent to the remediation work of putting both wells on pump, preliminary results indicate that gas production has increased dramatically.

The Decision Tree Triage Form and Data Collection Forms when completed provide a stripper gas well operator with a methodology to consistently review, analyze and correct wells experiencing abnormal production decline.

A procedure guide and summary report that will also evaluate the results of the methodology and implemented procedures will be completed by August 31, 2001.

References:

Not applicable.

Bibliography:

Not applicable

List of Acronyms and Abbreviations:

Not applicable.

Appendices:

Appendix 1	Decision Tree: Triage Form for Abnormal Production Decline Review
Appendix 2	Tubing Plunger Data Collection Form
Appendix 3	Casing Plunger Data Collection Form
Appendix 4	Pumping Unit Data Collection Form
Appendix 5	Swab or Flow Well Data Collection Form
Appendix 6	Study Group Analysis Summary
Appendix 7	Vogel Inflow Performance Relationship Chart

Appendix 1

Stripper Gas Well Decision Tree Analysis Abnormal Production Decline Triage Form

Date of Analysis ____ / ____ / ____
Lease ____
Well ID Number ____
Artificial Lift Mechanism ____

Step	Phase I: Identify the Problem Well	Yes	No
1.	Identify Abnormal Production Decline from “Priority”	_____	_____
2.	Review Production Decline Curve and Forecast	_____	_____
3.	Check with Pumper to Verify Problem Still Exists	_____	_____
4.	Check for Metering Inaccuracy	_____	_____
5.	Check Integrity of Gas Gathering System	_____	_____
	Phase II: Measure the Problem		
6.	Prepare Data Collection Form	_____	_____
7.	Check for Change in Sales Line Pressure	_____	_____
8.	Check for Change in Fluid Production	_____	_____
	Phase III: Solve the Problem		
9.	Check Flow Performance Chart: Vogel IPR Curve	_____	_____
10.	Is Well Producing at Optimum Production Rate?	_____	_____
11.	Optimize Fluid Removal Methodology	_____	
12.	Review for Compression	_____	
13.	Shut In for Bottom Hole Pressure Analysis	_____	
14.	Review to Shut In, to Sell, or to Plug and Abandon	_____	
15.	No further Analysis Required, Continue to Produce	_____	

Appendix 2

Stripper Gas Well

Data Collection Form for Problem Well Analysis

Lease Name and Well No: _____
Date: / /

Tubing Plunger, TPL

I. Field – Well Information

Producing Formation _____

Tubing Pressure: Begin/End _____ / _____ Psi

Casing Pressure: Begin/End _____ / _____ Psi

Tubing Plunger System style _____

Cycles per Day/Min On _____ / _____ Min

Date Cycles Last Adjusted _____ / _____ / _____

Previous Cycles per Day/ Min On _____ / _____ Min

Domestic Gas Usage Yes / No

Gas Gathering System Operating Psi _____ Psi

Additional Cycling in Gathering System _____

II. Field – Current Rate of Production

Oil, Bbl Oil per Week / Day	___BOPW/ ___BOPD
Gas, Mcf per Week / Day	___MCFW/ ___MCFD
Water, Bbl Water per Week	BWPW/ BWPD

III. Field – Comments and Recommendations

IV. Analytical Data

Perforated Interval(s)	_____
Casing Size	_____ In
Tubing Size	_____ In
Depth of Tubing	_____ Ft
Sales Line Size	_____ In
Sales Line Length	_____ Ft
Flowing Bottom Hole Pressure(FBHP)	_____ Psi
Last Shut In date and Pressure(SIBHP)	_____ Psi

V. Vogel Chart Analysis

Ratio of FBHP/SIBHP _____
 Estimated Maximum Production Rate
 BOPD MCFD

VI. Forecasted Rates of Production

Oil, Bbl Oil per Week / Day ___BOPW/ ___BOPD
Gas, Mcf per Week / Day MCFW/ MCFD

VII. Date and Description of Last Well Work

VIII. Comments and Recommendations

Estimated Cost of Recommendation	\$ _____
Estimated Daily MCFEQ Increase	\$ _____
M\$ per MCFDEQ	\$ _____
Estimated Payout, Months	

Appendix 3

Stripper Gas Well Data Collection Form for Problem Well Analysis

Lease Name and Well No: _____
Date: ____/____/____

Casing Plunger, CPL

I. Field – Well Information

Producing Formation _____
Flowing Casing Pressure _____ Psi
Casing Plunger Style _____
Trips per Week _____
Cycles per Day / Min On _____ / _____ Min
Domestic Gas Usage Yes / No
Gas Gathering System Operating Psi _____ Psi
Additional Cycling in Gathering System _____
Last Fluid Level Shot: Date/Depth _____ / _____ Ft

IV. Analytical Data

Perforated Interval(s) _____
Casing Size _____ In
Flow Intermittent / Continuous
Stand Depth _____ Ft
Sales Line Size _____ In
Sales Line Length _____ Ft
Flowing Bottom Hole Pressure(FBHP) _____ Psi
Last Shut In date and Pressure(SIBHP) _____ Psi

V. Vogel Chart Analysis

Ratio of FBHP/SIBHP _____
Estimated Maximum Production Rate
_____ BOPD _____ MCFD

II. Field – Current Rates of Production

Oil, Bbl Oil per Week / Day _____ BOPW/ _____ BOPD
Gas, Mcf per Week / Day _____ MCFW/ _____ MCFD
Water, Bbl Water per Week _____ BWPW/ _____ BWPD

VI. Forecasted Rates of Production

Oil, Bbl Oil per Week / Day _____ BOPW/ _____ BOPD
Gas, Mcf per Week / Day _____ MCFW/ _____ MCFD

VII. Date and Description of Last Well Work

III. Field – Comments and Recommendations

VIII. Comments and Recommendations

Estimated Cost of Recommendation \$ _____
Estimated Daily MCFEQ Increase \$ _____
M\$ per MCFDEQ \$ _____
Estimated Payout, Months _____

Appendix 4

Stripper Gas Well Data Collection Form for Problem Well Analysis

Lease Name and Well No: _____
Date: ____/____/____

Pumping Unit Well, PJEM or PJGE

I. Field – Well Information

Prime Mover _____
Producing Formation(s) _____
Flowing Tubing Pressure _____ Psi
Flowing Casing Pressure _____ Psi
Pump Schedule _____
Stroke Length _____ In
Unit Speed _____ SPM
Date Cycles Last Adjusted ____/____/____
Previous Cycles _____
Domestic Gas Usage Yes / No
Gas Gathering System Operating Psi _____ Psi
Last Fluid Level Shot Date / Depth ____/____ Ft

II. Field – Current Rates of Production

Oil, Bbl Oil per Week / Day ____BOPW/ ____BOPD
Gas, Mcf per Week / Day ____MCFW/ ____MCFD
Water, Bbl Water per Week ____BWPW/ ____BWPD

III. Field – Comments and Recommendations

IV. Analytical Data

Perforated Interval(s) _____
Casing Size _____ In
Tubing Size _____ In
Rod Size _____ In
Pump Description _____
Depth of Tubing _____ Ft
Sales Line Size _____ Ft
Sales Line Length _____ Ft
Flowing Bottom Hole Pressure (FBHP) _____ Psi
Last Shut In date and Pressure (SIBHP) ____/____ Psi

V. Vogel Chart Analysis

Ratio of FBHP/SIBHP _____
Estimated Maximum Production Rate
____ BOPD ____ MCFD
____ BOPD ____ MCFD

VI. Forecasted Rates of Production

Oil, Bbl Oil per Week / Day ____BOPW/ ____BOPD
Gas, Mcf per Week / Day ____MCFW/ ____MCFD

VII. Date and Description of Last Well Work

VIII. Comments and Recommendations

Estimated Cost of Recommendation \$ _____
Estimated Daily MCFEQ Increase \$ _____
M\$ per MCFDEQ \$ _____
Estimated Payout, Months _____

Appendix 5

Stripper Gas Well Data Collection Form for Problem Well Analysis

Lease Name and Well No: _____
Date: ____/____/____

Swab Well, SWB or Flowing Well, FLW

I. Field – Well Information

Producing Formation _____
Flowing Tubing Pressure _____ Psi
Flowing Casing Pressure _____ Psi
Date Last Swabbed ____/____/____
Fluid Recovered _____ Bbls
Domestic Gas Usage Yes / No
Gas Gathering System Operating Psi _____ Psi
Last Fluid Level shot Date / Depth ____/____ Ft

IV. Analytical Data

Perforated Interval(s) _____
Casing Size _____ In
Tubing Size _____ In
Depth of Tubing _____ Ft
Sales Line Size _____ In
Sales Line Length _____ Ft
Flowing Bottom Hole Pressure(FBHP) _____ Psi
Last Shut In date and Pressure(SIBHP) _____ Psi

V. Vogel Chart Analysis

Ratio of FBHP/SIBHP _____
Estimated Maximum Production Rate
_____ BOPD _____ MCFD

II. Field – Current Rate of Production

Oil, Bbl Oil per Week / Day ____ BOPW/ ____ BOPD
Gas, Mcf per Week / Day ____ MCFW/ ____ MCFD
Water, Bbl Water per Week ____ BWPW/ ____ BWPD

VI. Forecasted Rates of Production

Oil, Bbl Oil per Week / Day ____ BOPW/ ____ BOPD
Gas, Mcf per Week / Day ____ MCFW/ ____ MCFD

VII. Date and Description of Last Well Work

III. Field – Comments and Recommendations

VIII. Comments and Recommendations

Estimated Cost of Recommendation \$ _____
Estimated Daily MCFEQ Increase \$ _____
M\$ per MCFDEQ \$ _____
Estimated Payout, Months _____

Appendix 6

Study Group Analysis Summary

Lease Name	Well Type	Major Cause of Abnormal Decline	Remediation Strategy	Estimated Cost	Forecasted
Production					
1. E. Carrick #1	TPL	Mechanical Failure – Hole in 4 1/2” Casing	Repair and Return to Production	\$18,000	35 mcf
2. R. Florence #1	TPL	Gas System restriction	Continue to Review	\$15,000	Unknown
3. R. Krapps #1	TPL	Mechanical Failure – Hole in 4 1/2” Casing	Repair and Return to Production	\$18,000	10 mcf
4. M. Pickenpaugh #3	TPL	Mechanical Failure – Hole in 4 1/2” Casing	Repair and Return to Production	\$18,000	10 mcf
5. OP Combs #4B	TPL	Mechanical Failure – Hole in 4 1/2” Casing	Repair and Return to Production	\$18,000	12 mcf
6. Reed #1	SWB	Mechanical Failure – Hole in 4 1/2” Casing	Repair and Return to Production	\$5,000	10 mcf
7. W. Fitzgerald #1	TPL	Fluid Accumulation	Run Tubing and Tubing Plunger	\$10,000	7 mcf
8. J. McCall #1	TPL	Gas System Restriction	Continue to Review	\$0	
9. R. Krapps #2	TPL	Mechanical Failure – Hole in 4 1/2” Casing	Repair and Return to Production	\$18,000	10 mcf
10. A. Larrick #1	SWB	Fluid Accumulation	Run Tubing and Tubing Plunger	\$10,000	10 mcf
11. Richey Dunkle #1	SWB	Fluid Accumulation	Run Tubing and Rods, PJG	\$18,000	7 mcf
12. Richey Lucille #1	SWB	Fluid Accumulation	Run Tubing and Rods, PJG	\$18,000	20 mcf
13. JB Bigley #1	SWB	Fluid Accumulation	Run Tubing and Tubing Plunger	\$10,000	5 mcf
14. Dee D. Dunkle #1	SWB	Fluid Accumulation	Run Tubing and Rods, PJG	\$18,000	10 mcf
15. Richey Reed #1	SWB	Fluid Accumulation	Swab	\$1000	
16. OP Chritopher #26C	TPL	Fluid Accumulation	None, Well Optimized	\$0	
17. Owen Reed #1	TPL	Gas System Restriction	Continue to Review, PJG	\$18,000	7 mcf
18. C. Williams #1	TPL	Fluid Accumulation	Run Tubing and Rods, PJG	\$18,000	40 mcf
19. Presdee #1	TPL	Fluid Accumulation	Run Tubing and Rods, PJG	\$18,000	15 mcf
20. M. Pickenpaugh #4	TPL	Fluid Accumulation	Run Tubing and Rods, PJG	\$18,000	10 mcf
21. John Jenkins #1	TPL	Fluid Accumulation	Domestic Gas Issue	\$0	
22. Ellis Miller #3	SWB	Fluid Accumulation	Run Tubing and Tubing Plunger	\$10,000	10 mcf
23. OP Brown #15B	TPL	Mechanical Failure – Hole in 4 1/2” Casing	Repair and Return to Production	\$5,000	10 mcf
24. L. Stephenson #2	SWB	Fluid Accumulation	Run Tubing and Rods, PJG	\$18,000	\$0

Appendix 7