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Abstract

A study group of 376 Clinton Sand wells in Ohio provided data to determine the historic frequency of the problem of abnormal production declines in stripper gas wells and the causes of the abnormal production decline. Analysis of the historic frequency of the problem indicates over 70% of the wells experienced abnormal production decline. The most frequently occurring causes of abnormal production declines were determined to be fluid accumulation (46%), gas gathering restrictions (24%), and mechanical failures (23%). Data collection forms and decision trees were developed to cost-effectively diagnose the abnormal production declines and suggest corrective action. The decision trees and data collection sheets were incorporated into a procedure guide to provide stripper gas well operators with a methodology to analyze and correct abnormal production declines. The systematic methodologies and techniques developed should increase the efficiency of problem well assessment and implementation of solutions for stripper gas wells.

This final technical progress report provides a summary of the deliverables completed to date, including the results of the remediations, the procedure guide, and the technology transfer. Due to the successful results of the study to date and the efficiency of the methodology development, two additional wells were selected for remediation and included into the study. Furthermore, the remediation results of wells that were a part of the study group of wells are also described.

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Introduction

The goal of this research program was 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 provided the 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 abnormal production declines. The most frequently occurring causes of abnormal production declines were determined to be fluid accumulation (46%), gas gathering restrictions (24%), and mechanical failures (23%). Data collection forms and decision trees were developed to cost-effectively diagnose the abnormal production declines and suggest corrective action. Economic techniques to solve the most frequently occurring problems were researched and implemented on two wells. The decision trees and data collection forms developed as a result of this research were incorporated into a procedure guide to provide operators with a methodology to analyze and correct abnormal production decline in stripper gas wells using commonly available data. The systematic methodologies and techniques developed should increase the efficiency of problem well assessment and implementation of solutions for stripper gas wells.

This final technical report summarizes the results of the following steps for this study:

- Establish a study group of stripper gas wells
- Review and identify problem wells exhibiting abnormal decline
- Categorize individual well problems
- Summarize the frequency of individual well problem
- Develop decision trees
- Develop diagnostic tools to evaluate declines in problem wells
- Identify cost effective techniques to solve the most frequently experienced problems
- Apply methodology to a group of wells where recent problems have developed to identify problem
- Select the two wells with the greatest potential for increase in production and having the most frequently occurring problems
- Evaluate the results of the methodology and the implemented procedures
- Describe the procedure guide

The remediation results of wells that were a part of the study group of wells but not selected as part of this study for remediation are also described. Furthermore, due to the successful results of the study to date and the efficiency of the methodology development, two additional wells were selected for remediation, included into the study, and the results described herein.

Executive Summary

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

Preliminary research indicated that over 85% of the wells in the initial study group exhibited some period of abnormal production decline during their entire production history. Analysis of the final study group that consisted of 270 Clinton Sand wells located in Ohio indicated that over 70% of the wells had experienced abnormal production decline in the past five years alone. The following categories of potential individual well problems were identified as causes for the abnormal production declines; reservoir damage, reservoir depletion, fluid accumulation problems, precipitate plugging, mechanical failure, gathering system restrictions, metering inaccuracies, or unknown. Of all the causes of abnormal production declines, over 90% were caused by a fluid accumulation (46%), gas gathering restrictions (24%), and mechanical failures (23%).

It was originally believed the predominant cause of abnormal production decline of stripper gas wells was due to formation damage. The most significant finding as a result of this research was that the most common cause of abnormal production decline was due to the suppression of the bottom hole producing pressure by fluid accumulation and not formation damage. The reason formation damage may not be a significant cause of abnormal production decline in stripper gas wells as originally thought is because most wells have produced for a significant period of time at relatively low flow rates. Therefore, if no foreign fluids were introduced into the well during this time then the formation has very little reason to develop formation damage.

Data collection forms and decision trees were developed as a result of this research to cost-effectively diagnose the most common problems. The Decision Tree Triage Form and the Data Collection Forms developed provide a logical review of the data necessary for analyzing the cause of the abnormal production decline.

A small group of wells which were currently experiencing abnormal production decline were analyzed using the methodologies, decision trees, and data collection forms developed and then ranked to select two wells for remediation with the greatest potential for production increase and which also had the most frequently occurring problem, fluid accumulation.

The results of the research indicate that the methodologies and techniques developed are practical and suitable for most stripper gas well operators utilizing commonly available data. The decision trees and data collection forms were incorporated into a procedure guide to provide operators with a low cost methodology to analyze and correct abnormal production decline in stripper gas wells. The systematic methodologies and techniques developed should increase the efficiency of problem assessment and implementation of solutions for stripper gas wells.

This final technical progress report provides a summary of all steps completed to date including the results of the two remediations, the procedure guide, and the technology transfer. Due to the successful results of the study to date and the efficiency of the methodology development, two additional wells were selected for remediation and the results described herein.

Experimental

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

Results and Discussion

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

The Department of Energy (DOE) originally believed that the predominant cause of abnormal production decline of stripper gas wells was from due to damage. The most significant finding as a result of our research was that abnormal production decline was due to the suppression of the bottom hole producing pressure and not formation damage. The reason formation damage may not be a significant cause of abnormal production decline in stripper gas wells is because most wells have produced for a significant period of time at relatively low flow rates. Therefore, if no foreign fluids were introduced into the well during this time then the formation has very little reason to develop formation damage.

This final report summarizes the results of the following tasks to develop the procedure guide:

- Establish a study group of stripper gas wells
- Review and identify problem wells exhibiting abnormal production decline
- Categorize individual well problems
- Summarize the frequency of individual well problems
- Develop decision trees
- Develop diagnostic tools to evaluate declines in problem wells
- Identify cost effective techniques to solve the most frequently experienced problems
- Apply methodology to a group of wells where recent problems have developed
- Select the two wells with the greatest potential for increase in production and also having the most frequently occurring problem
- Evaluate the results of the methodology and the implemented procedure
- Describe the procedure guide

Each task as identified above will be reviewed in detail along with discussion of the methodologies utilized.

The remediation results of wells that were a part of the study group of wells but not selected as part of this study for remediation are also described. Furthermore, due to the successful results of the study to date and the efficiency of the methodology development, two additional wells were selected for remediation, included into the study, and the results described herein.

Task 1 – Establish a Study Group of Stripper Gas Wells
This task as originally described in the Statement of Work in the original proposal is as follows: *"The contractor shall establish a study group of stripper gas wells from a group of over 500 wells which they have access to. The study group shall include wells of various depths with a wide variety of producing mechanisms. The wells will be primarily located in the Appalachian Basin, but may also include some wells in the Permian and Powder River Basin."*

Data Reduction and Methodology
The original database used for this study contained all wells in which Artex Oil Company or its affiliate, Arloma Corporation, had a working or royalty interest. The Artex Oil Company database consists of 592 wells located in Kansas, New Mexico, Ohio, Texas, West Virginia and Wyoming. The study group was reduced to 457 wells directly operated by Artex Oil Company due to the ability to access, collect, and interpret data and to more closely affect the outcome of recommended procedures. The study group was further reduced to 431 by eliminating wells that have been sold, plugged, or classified as non-stripper. The 431 wells utilized for the study group produced primarily from the Clinton Sand formation and are located primarily in Guernsey, Muskingum, Morgan, Noble, Tuscarawas and Washington counties, Ohio.

James Engineering, Inc. utilized Landmark Graphics ARIES® database management software to manage the master, product and economic tables, and to graphically analyze abnormal production declines with the ARIES® production plotting function.

A review of the master table data was performed for each well to ensure that each well file was complete with the following information: permit number, completion date, total depth, perforated interval, producing reservoir, and producing mechanism. The completion date was compared to the production table data to determine if the complete production history was present. Production history gaps were then filled in as possible with data from two state maintained databases and other sources. The databases maintained by the state of Ohio are the Risk Based Database Management System, or RDBMS, and the Production of Oil and Gas in Ohio database, or POGO, maintained by the Ohio Division of Natural Resources Division of Oil and Gas and the Ohio Geological Survey, respectively.

A forty-year semi-log plot of monthly oil and gas production from the product table was then prepared for each well based upon information from the master and product table. The plot title block contained the lease name, well number, county, state, completion date, producing reservoir, producing mechanism, and total depth. See Appendix 1 for an example of a typical production plot utilized for abnormal production decline review.

The methodology to "Establish a Study Group of Stripper Gas Wells" was as follows:

1. Utilize all wells in Artex Oil Company ARIES® database.
2. Eliminate wells that were outside operated.
3. Eliminate wells that were sold, plugged, shut-in, or classified as non-stripper.
4. Enter completion date, total depth, producing reservoir, perforation interval, and producing mechanism from well file and completion report information into ARIES® Master Table.
5. Compare completion date to monthly production data in ARIES® Product Table for completeness of product table.

6. Enter missing production data into ARIES® Product Table from RDBMS, POGO, or other sources.
7. Plot entire production history utilizing monthly oil and gas production volumes from the ARIES® Master and Product tables for all study group wells on forty-year semi-log plots for abnormal production decline review.

Task 2 – Review and Identify Problem Wells Exhibiting Abnormal Declines

This task as originally described in the Statement of Work in the original proposal is as follows: *"The contractor shall review and identify problem wells exhibiting abnormal declines from the study group of wells. This task shall be accomplished by taking the historical production information for the group of study wells and plotting the data on decline curves to present a historical perspective of how the wells have performed over their lives. Wells with greater than a 50% departure from an established decline trend for more than three months will be selected for analysis .A statistical analysis of the number of wells meeting this criterion will be prepared. The analysis shall include documenting wells that have declined and have been corrected, the cause of the decline, and the methods used to return the well to economic production."*

Data Reduction and Methodology

A forty-year production decline type curve was obtained for the Clinton Sand formation based upon extensive production analysis and experience in the Appalachian Basin. See Appendix 2 for a graphical presentation of this rate time curve on a semi-log plot. The type curve was overlaid on each production plot to attempt to match the actual production decline. The type curve was transferred to the forty-year production plot and compared to actual monthly production for abnormal production declines. An abnormal production decline was defined in our scope of work as a consecutive three-month period where the production fell below the type curve forecast by 50%. Each period of abnormal production meeting this criterion was identified on the curves remaining in the study group.

Two analyses to determine abnormal production decline were performed on each well. The first analysis identified abnormal declines over the entire life of the well while the second analysis focused on the period from January 1995 to December 1999. This five-year period represented the time that current management has operated the wells and therefore more detailed information was available. The total months of abnormal production were compiled for both the entire well life and the most recent five-year period. In addition, it was noted whether action taken to correct the abnormal production decline was permanently or intermittently obtained. Finally, the cause of the decline, if known, was noted and the corrective action, if known, documented. The corrective actions were studied further through well records and field reports then denoted as a mechanical and/or procedural.

Significantly, 388 wells of the 431 well study group, or 90%, exhibited some form of abnormal production decline, while 43 wells exhibited no abnormal production decline during their entire production history.

The study group was further reduced to 376 wells by eliminating those wells having insufficient production data for further analysis. Insufficient production data for this study is defined as monthly oil or gas data insufficient to accurately forecast production decline. The incomplete data could be missing or allocated production data. In many cases these were poorer wells at or near their economic limit.

Of the 376 well study group, 106 wells were identified as producing as forecasted during the period of January 1995 to December 1999. The last five years of production showed that 106 wells had experienced "normal" decline even though there were periods of abnormal production decline during the entire production history. This analysis resulted in a 270 well study group exhibiting abnormal production decline.

The methodology to "Review and Identify Problem Wells Exhibiting Abnormal Declines" is as follows:

1. Develop a forty-year production decline type curve for the Clinton Sand formation.
2. Transfer the forty-year production decline type curve to match the actual production plot.
3. Review and identify each well exhibiting abnormal production decline.
4. Identify the period abnormal production decline on each production well.
5. Identify the cause of abnormal production decline, if known.
6. Identify the method used to return the well to production, if known.
7. Eliminate the wells with insufficient production data.

Task 3 – Categorize Individual Well Problems
This task as originally described in the Statement of Work in the original proposal is as follows: *"Producing problems can occur at any point from the producing formation to the custody transfer point and be manifested in many different ways. Examples may include 1) Reservoir damage, 2) Reservoir depletion, 3) Fluid accumulation problems, 4) Precipitate plugging, 5) Mechanical failure of casing, tubing, plungers, rods or pumps, 6) Gathering system restrictions, and 7) Metering inaccuracies. There may be other problems, but in our experience, these are believed to be the major occurrences. A primary cause will be assigned to each."*

Data Reduction and Methodology
The categories of potential individual well problems are as follows:

- Reservoir damage
- Reservoir depletion
- Fluid accumulation problems
- Precipitate plugging
- Mechanical failure of casing, tubing, plungers, rods, or pumps
- Gathering system restrictions
- Metering inaccuracies
- Unknown

For the purposes of this study,

Reservoir damage is defined as reservoir permeability damage caused by producing, drilling, stimulating, or injecting foreign fluids into the reservoir.

Reservoir depletion is defined as pressure depletion of the producing reservoir drainage area sufficient to cause abnormal production decline due to interference or production of offset wells.

Fluid accumulation problems are defined as build-up of fluid (oil or water) due to ineffective artificial lift methods or primary production mechanism no longer capable of effectively lifting fluid from well while maintaining optimum production. Ineffective artificial lift methods can be further defined as swabbing programs, cycle changes for increased plunger runs. When the primary production mechanism was no longer able to lift fluids from the well, the well then required the installation of artificial lift mechanism or installation of tubing, or casing plunger, or tubing and tubing plunger to maintain optimum production.

Precipitate plugging is defined as plugging of perforations or immediate well bore area with paraffin or other precipitate materials.

Mechanical failures of casing, tubing, plungers, rods, or pumps are defined as casing leaks, tubing leaks, plungers sticking or wearing out, rods parting, tubing parting, or pumps failing due to wearing out or getting stuck.

Gathering system restrictions are defined as increased sales line pressure, fluid build up in the gas lines, or gas line failure.

Metering inaccuracies are defined as either gas meter problems leading to inaccurate chart readings or improper chart integration leading to invalid integration values.

Unknown is defined as a classification utilized when no other possible indication as to the most likely cause for abnormal production decline.

A primary cause was assigned to each well determined to have experienced abnormal production decline. The primary cause was defined as one that resulted in the majority of the abnormal production decline. Each well may also have experienced more than one period of abnormal decline in the five years analyzed. The primary cause assigned was the one that affected the majority of the abnormal decline periods.

For example, a well with a casing leak could also have a gathering system restriction, however, if the casing leak is not repaired the well could not be produced. Therefore, a Mechanical Failure due to a casing leak would be the primary cause for the abnormal production decline.

The methodology to "Categorize Individual Well Problems" is as follows:

1. Compare individual well production plots to type production decline curve.
2. Determine wells with abnormal production decline.
3. Perform a diagnostic review to determine primary cause.
4. Assign primary cause of abnormal production decline.

Task 4 – Summarize the Frequency of Individual Well Problems
This task as originally described in the Statement of Work in the original proposal is as follows: *"A statistical analysis will be prepared for the different causes of abnormal production decline identified in the problem wells. Knowing the most likely source of problem and symptoms of the problems should help stripper well operators diagnose and correct problems as they occur."*

Data Reduction and Methodology
Analysis for this potion of the study was limited to the period of 1995 through 1999 when Artex Oil Company had control of the operations of the wells since knowledge about the cause for abnormal production declines prior to 1995 was very limited or unavailable. 270 wells were identified as having experienced abnormal production decline for the period of 1995 - 1999.

Each well exhibiting abnormal production decline was assigned a primary category according to the information available from well files, first hand information, or through diagnostic information collected. It is important to note that while two or more causes may have contributed to the abnormal production decline, only one primary cause was assigned.

Table No. 1 Summary of the Frequency of Individual Well Problems

Category	**Number of Occurrences**	**% of the Total Number of Occurrences**
Fluid Accumulation Problems	124	45.9
Gathering System Restrictions	65	24.0
Mechanical Failure	61	22.6
Reservoir Depletion	10	3.7
Metering Inaccuracies	5	1.9
Unknown	4	1.5
Reservoir Damage	1	0.3
Precipitate Plugging	0	0.0
Total	**270**	**100.0 %**

The majority of abnormal production declines observed in the study group were the result of fluid accumulation in the well due to the need for artificial lift or ineffective fluid removal technology, as can be seen in Table No. 1, Summary of the Frequency of Individual Well Problems.

Our analysis indicates that many stripper gas wells do not experience abnormal production due to precipitation in the reservoir resulting in formation damage, but rather from failure to reduce the flowing bottom hole producing pressure sufficiently to maximize production. Failure to reduce the flowing bottom hole producing pressure is typically attributable to a misapplication of artificial lift or a failure in mechanical integrity.

Proof of failure to reduce the flowing bottom hole pressure has been observed often through the correct application of fluid removal technology or artificial lift. The production increases predicted by Vogel's Inflow Performance Relationship have been verified through the production increases observed as a result of completed well work.

The methodology to "Summarize the Frequency of Individual Well Problems" is as follows

1. Assign a primary category according to the information available from well files, first hand information, or through diagnostic information collected.
2. Determine the total number of occurrences for each category.
3. Summarize the frequency of the individual problems.

Task 5 – Develop Decision Trees
This task as originally described in the Statement of Work in the original proposal is as follows: *"Develop decision trees to identify the problem causing the production decline and select the most appropriate solution. The decision trees will utilize pressure and rate information gathered on the data collection forms as well as field test results to direct the operator to the most likely cause of the problem."*

Data Reduction and Methodology
The Decision Tree Triage Form, see Appendix 3, is a three-phase process to aid in identifying the most common production problems causing abnormal production decline. The Triage Form provides a methodology to evaluate the cause of abnormal production declines in stripper gas wells by identifying factors that affect the flowing bottom hole pressure. The Decision Tree Triage Form is divided into three sections, Phase 1: Identify the Problem Well, Phase 2: Measure the Problem Well, Phase 3: Solve the Problem Well. The overall philosophy of the Triage Form is to begin with the simplest analysis by eliminating the most common problems, and then expanding the analysis as the problem requires.

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

Step one in Phase 1 verifies the production decline data, curve, and forecast to ensure that they are appropriate and complete. A production variance report that compares actual to forecasted data would be incorrect if the wrong production data were used or an invalid decline forecast were applied to a production history. Type decline curve comparison was observed to provide a benchmark for analysis of abnormal production decline. Therefore, a type production decline curve was then applied to the forty-year production history plot to identify periods of abnormal production, that is, when actual production deviated from typical decline.

A graphical representation of the complete monthly production history of a well is important in abnormal production decline analysis. Reviewing only a portion of the well's production history often leads to invalid conclusions. During the course of the study, it was observed that water production histories were often incomplete, while oil production volumes were only recorded at the time of lease transfer or sale. All fluid production volumes are important when analyzing stripper gas wells and should always be recorded in a summary format for easy reference.

Step two in Phase 1 verifies the problem still exists either by talking directly to the pumper and/or reviewing the most recent weekly pumper reports. Oftentimes the cause of the abnormal production decline has already been resolved by the time a production variance report is prepared. Pumper interaction is extremely important to the success of stripper gas well operation.

Step three in Phase 1 verifies metering accuracy by comparing individual meter volumes to master meter volumes or gas chart integration statements to the actual gas chart. An example of a source of error could be an orifice plate change that was not identified by the chart integration company resulting in improper gas volume calculation based upon chart integration.

Step four in Phase 1 verifies the gas gathering system integrity typically through pressure testing.

Decision Tree Triage Form - Phase 2, Measure the Problem Well
Phase 2 analysis continues with the same philosophy, to begin with the simplest analysis to eliminate the most common problems, and then expand the analysis as the problem requires. The production manager assimilates data to solve the problem of abnormal production decline by identifying those well production characteristics that would typically result in abnormal production decline and changes in flowing bottom hole pressure. The low profitability nature of stripper gas wells requires that minimum effort be expended for maximum benefit.

Step five in Phase 2 completes the appropriate Data Collection Form. Data Collection Forms were developed for tubing plunger wells, casing plunger wells, pumping wells, and swab or flow wells, see Appendices 4 – 7. Specific data applicable to each production method was identified. Sections I, II, and III were designed for field personnel to complete, while sections IV, V, VI, VII, and VIII were for the production manager to complete.

The Data Collection Forms are discussed in detail in Task 6 - Develop Diagnostic Tools to Evaluate the Cause of Declines in Problem Wells. The Data Collection Forms require well information, fluid production volumes, pressure data, and well analysis for specific production methods.

Particular attention should be focused on those factors that could adversely affect the flowing bottom hole pressure during the preparation of the Data Collection Forms. The production manager should look for changes in sales line pressures, surface wellhead pressures, production cycles, and fluid production volumes.

Decision Tree Triage Form - Phase 3, Solve the Problem Well
Completing this section of the Triage Form should result in a solution to the cause of the abnormal production decline.

Step 6 in Phase 3 is to complete an Alternative Production Method Decision Form, see Appendix 8. This form provides a methodology to evaluate the costs and benefits of various production methods. The application of each method is based upon the operator's experience in depleting the producing reservoir to its ultimate economically recoverable limit. The cost of implementing each production method should also be based upon operator experience. Our experience indicates that the application of a pumping unit and compression will yield the highest recovery.

Vogel's Inflow Performance Relationship, discussed in detail in Task 6 - Develop Diagnostic Tools to Evaluate the Cause of Declines in Problem Wells, should be utilized to determine the percentage of maximum production increase to be expected based upon the reduction in flowing bottom hole pressure. The cost to implement each alternative method and economic benefit should be based upon the individual operator's experience and costs depending upon the depth and application.

Four methods are recommended to compare the economic benefit of the alternative methods, the incremental mcfd increase, M$ per Mcfd, payout, and net present value.

The first method considers the incremental mcfd increase to be obtained from the various alternatives. This guideline provides one aspect for comparison, but its value alone does not indicate the economic benefit of the method.

The second economic method compares the various alternatives based upon M$ per mcfd ratio. We recognize that working over wells is very comparable to buying existing production and the economic calculation we often look at for buying wells is the amount of dollars spent per mcf per day of production increase. Specifically, the ratio is calculated by dividing the dollars to be invested by 1000, or M$, by the mcf per day of production increase. This ratio should provide the production manager with one benchmark to compare the investment potential of the proposed recommendation to other opportunities.

A third method often utilized to determine the potential economic merit of the well work is the time for the project to payout measured in months. Typically, any project with a payout period less than one year would proceed without much further analysis required while those projects with longer payouts should be reviewed closer. Payout provides a quick and second methodology to determine the economic viability of a proposed project.

While incremental production, M$ per mcfd, and payout are considered good indicators for comparing investment alternatives, the calculation of net present value based upon future reserves and cash flow should be considered as the superior method to determine economic benefit over the life of the project

At the completion of the economic evaluation, the production manager can then evaluate the best course of action utilizing the data assimilated for the specific producing method. The production manager could also rank all of the investment opportunities against the capital dollars available based upon the cost of the proposed project, the ratio of invested dollars to production increase, and the payout time of the project. This list of proposed projects and their economic ranking would provide a quick reference list for future proposals that come available.

Step 7 in Phase 3 recommends completing the proposed work.

Step 8 in Phase 3 recommends reviewing the well to shut-in, sell, or to plug and abandon.

Step 9 in Phase 3 recommends continuing to produce the well since the well cannot be economically repaired, therefore no further analysis is required.

The methodology to "Develop Decision Trees" is as follows:

1. Begin with the overall philosophy to begin with the simplest analysis first by eliminating the most common problems, and then expanding the analysis as the problem requires.
2. Develop a decision tree to coincide with the overall philosophy that provides a systematic method of reviewing wells with abnormal production decline.
3. Identify those factors that could make it appear that there was a problem with the well.
4. Prepare a systematic data collection form to analyze wells with abnormal production decline.
5. Develop a form to compare alternative methods of production.

Task 6 – Develop Diagnostic Tools to Evaluate the Cause of Declines in Problem Wells
This task as originally described in the Statement of Work in the original proposal is as follows: *"Develop data-collection forms of pertinent information to assist in analysis of problem wells. Well equipment will be analyzed for mechanical failure. Shut-in and producing pressure information will be gathered to analyze bottom hole producing pressures. Fluid levels and other information will be collected to determine the effects of fluid on bottom hole pressure. Fluid production histories will be confirmed to determine what effect gas/liquid ratios have on stripper gas well performance. Pressure drops from producing formation to the gas sales point will be analyzed.*

Data Reduction and Methodology
The development of diagnostic tools capable of analyzing problem wells required determining who had responsibility for achieving and maintaining maximizing production, what were the current methods of monitoring production, and what was the basis for determining the productive potential of stripper gas wells.

Well Production Responsibility
The production manager and the well pumper share the responsibility of achieving and maintaining maximum production volumes from stripper gas wells. The very nature of stripper gas well production, specifically marginal gas well production, limits the amount of time and money available to maximize production. Therefore, development of diagnostic tools to evaluate the cause of abnormal production decline assists both the production manager and the pumper to react when maximum production is not achieved.

The primary responsibility of the pumper is to maximize production of each well, however, maximizing production entails many responsibilities. These other responsibilities often include well, pumping unit, and flow line maintenance in addition to chart changing, domestic gas, and scheduling fluid removal services. The pumper is often more familiar with the producing characteristics of the stripper wells than the production manager. With general guidance from the production manager, the pumper makes adjustments that affect the daily production from each well. The pumper has the ability to observe first hand the changes in well performance through changes he makes by observing pressure and production trends, for example production cycles. Through the consistent collection and analysis of data, the pumper can develop the skill and knowledge to keep many stripper wells that are close to the economic limit from becoming "problem wells".

The production manager must minimize the number of problem wells in day-to-day operations to maximize well production. The production manager, like the pumper has other responsibilities, has limited time for problem wells due to supervisory responsibilities, environmental, governmental and land duties, and budgetary restrictions. Therefore, it is critical that the production manager and the pumper spend as little time as possible assembling the data and analyzing the causes of abnormal well declines in stripper gas wells.

Current Methods of Monitoring Production
The three primary methods used by Artex Oil Company to assist in achieving and maintaining optimum production include weekly pumper production reports, monthly gas production chart integration statements, and monthly "Priority" production monitoring reports.

Simple weekly production reports completed by well pumpers are designed to provide a list of active wells and to monitor weekly gas, oil, and water production volumes. In addition, fluid volumes shipped from location, orifice plate changes, and a comment section allows pumpers to note significant changes in lease operations. The production manager and pumper review the production reports at weekly meetings where they discuss and resolve many issues. A sample of the weekly production report can be seen in Appendix 9.

Monthly gas chart integration statements are another tool utilized by the production manager to identify potential stripper gas well production problems. The integrated volumes produced are reviewed, entered, and tracked in the ARIES® Product Table and used to prepare "Priority" production variance reports. The produced integration volumes are not the same as the gas sales volumes because they do not account for line loss. However, they are effective in reflecting production trends and abnormal production declines.

The "Priority" production monitoring report was developed to allow operators to set a production goal and then monitor gas production volumes from their wells. James Engineering, Inc. was involved in a cost-sharing venture with BDM-Oklahoma under the requirement entitled "Research and Development by Small Independent Operators to Provide Solutions towards Production Problems." A computer program called "Priority" was developed to help users quickly identify opportunities to maximize field profitability through that cost-sharing venture.

"Priority" is a MS® Excel based program designed to accept imported actual and forecasted production information from an ARIES® database. The report generated from "Priority" assists production managers as follows: "By comparing actual oil and gas production volumes to forecasted producing rates for a specific period, the program generates a discrepancy report which can rank the wells in order of the greatest production deficiency to identify wells that require attention." A sample of the "Priority" report is included in Appendix 10.

The "Priority" production monitoring report quickly identifies wells that do not meet forecasted values and allows the pumper to measure well performance to maintain optimum production volumes. The production manager and the pumper review the production reports at a weekly meeting where they discuss and resolve many production related issues.

Many problems identified by "Priority" are routinely taken care of by the pumper or the production manager. It has been said, "What gets measured gets done". The "Priority" production monitoring report utilized by Artex Oil Company sets a production goal and then compares it to actual production. The production goal allows the pumper to measure well performance to maintain optimum production volumes.

Determining the Productive Potential of Stripper Gas Wells

Experience indicates that the productive potential of stripper gas wells can be estimated by utilizing information typically available to most operators. Current literature indicates that a well's productive potential is inversely proportional to the ratio of the flowing bottom hole pressure to the shut-in bottom hole pressure.

Research completed by Vogel showed that "Fluid flow in a reservoir is caused by movement of fluid from a high pressure area to a low pressure area and that fluid flow increases as the differential pressure increases." "Vogel presents an Inflow Performance Relationship, or IPR for determining producing rate efficiency based upon the ratio of the well bore pressure to the reservoir pressure. Vogel's IPR is based upon the following formula:

$$Q/Qm = 1.0 - 0.2*(P_{fbh}/P_{sibh}) - 0.8*(P_{fbh}/P_{sibh})^2$$

Where
Q = Flow rate in mcfd at the current flowing bottom hole pressure.
Qm = Maximum flow rate in mcfd at minimum flowing bottom hole pressure.
Pfbh = Flowing Bottom Hole Pressure.
Psibh = Shut in Bottom Hole Pressure.

The Flowing Bottom hole pressure, or P_{fbh}, equals the summation of $P_{wh} + P_{gc} + P_{oc} + P_{wc}$, where

P_{wh} = Casing or tubing well head pressure
P_{gc} = Pressure exerted by gas column
P_{oc} = Pressure exerted by oil column
P_{wc} = Pressure exerted by water column

The total fluid column can be identified from an acoustic liquid level instrument, while the percentage of the oil and water portions are assumed to be equivalent to previous production rates of the respective reservoir. For example, a 200 ft column of fluid for a well averaging 1 barrel of water per day and 1 barrel of oil per day could be divided proportionately between the oil and water.

A graphical representation of the Vogel IPR formula showing the relationship of the ratio of Pfbh/Psibh to the percentage of the maximum producing rate, Q/Qm is provided as Appendix 12. Vogel's relationship indicates that greater than 85% of the reservoir's maximum flow rate will be achieved when the flowing bottom hole pressure is 33% of the shut in reservoir pressure.

It should be noted that Vogel assumed the reservoir is a solution gas drive and that there is no reservoir skin damage in the development of his IPR. Our experience and research indicate that these assumptions are valid when determining the folds of increases expected by optimizing the pressure drop at the bottom of the hole.

Data Collection Forms
As previously discussed in Task 5, Develop Decision Trees, the data collection forms developed as a result of this research have been divided into eight sections, three for the pumper to complete with field related data and five for the production manager to complete, analyze, and make recommendations, see Appendices 4 - 7.

Data Collection Form Section I requests general well information pertinent to the producing characteristics of the well to be completed by the well tender. Data requested includes the producing formation(s), the beginning and ending production cycle surface pressure information, cycles per day, trips per week for tubing plungers. Additional information includes previous cycle information, unit speed and stroke length for pumping units, domestic gas usage, gas gathering system information, and fluid level information. All information the pumper should know intimately.

The data collection forms also ask for the presence of domestic gas usage. Domestic gas supplied from the casing-tubing annulus has been observed to adversely affect stripper gas well production by creating a pressure drop to the casing-tubing annulus, depleting storage volume, and allowing fluid to build-up in the annular area instead of to the tubing.

The recording of pressure and fluid production information is often neglected. Shut-in pressures should be obtained at least once per year and can often be obtained during normal maintenance. All flowing bottom hole pressure and shut in bottom hole pressure information is important when analyzing stripper gas wells and should be recorded in a summary format for future reference.

Data Collection Form Section II: Current Daily Production Rates specifies the current daily production rates for the oil, gas, and water. It may be helpful to review weekly pumper's reports to determine the average daily fluid production, since total fluid production volumes are often not included in the production history until oil or water is transferred from the lease.

Data Collection Form Section III: Comments and Recommendations allows the pumper to enter comments, additional data, and recommendations for the problem well based upon his first hand knowledge of the producing characteristics. 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 or solution.

The Data Collection Form is then returned to the production manager typically at the next week's pumper's meeting. Sections IV-VII are for the production manager to complete.

Data Collection Form Section IV: Analytical Data requests data to assist in estimating the producing potential of the well. Typical data required is perforated interval, casing size, tubing size, depth of tubing, sales line size, sales line length, flowing bottom hole pressure, and last shut in pressure and date.

Data Collection Form Section V: Vogel Chart Analysis requests data to determine the well's productive potential by calculating the ratio of the FBHP to the SIBHP. Using the calculated ratio and Vogel's Inflow Performance Relationship Curve, the percentage of the maximum producing rate can be determined. Knowing the current producing rates and the maximum producing rate expected, the net production increase will determine the amount of production available to pay out the proposed work.

The ratio of the flowing bottom hole pressure to the shut-in bottom hole pressure is entered on the y-axis of Vogel's IPR curve, across to the intersection of the chart, then down to the x-axis. The x-axis intersection represents the percentage of maximum production currently being achieved. 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 currently producing at 10 mcfd has a maximum producing rate of 12 mcfd, calculated by dividing 10 mcfd by 0 .83, if the flowing bottom hole pressure was reduced to 0 psi.

Data Collection Form Section VI: Forecasted Rates of Production is for calculating the forecasted rates of production to be expected based upon current production, Vogel IPR analysis, and decline curve analysis. Further analysis may be required if there are inconsistencies between IPR and decline curve analysis.

Data Collection Form Section VII: Date and Description of Last Well Work will contain a brief description of the last well work completed. This will remind the production manager what has been done already and the results obtained. This is helpful when planning future well work or whether it is necessary to review a more complete history of the well work.

A chronology of all well work performed from completion to the present is helpful in abnormal production decline analysis to determine the next course of action. All fluid and pressure data should be noted as part of the chronological record including beginning and ending swabbing fluid levels, total and type of fluid swabbed, shut in pressures, casing and tubing pressures, test volumes, and equipment modifications.

Data Collection Form Section VIII: Comments and Recommendations details how to proceed correcting the abnormal well decline based upon the review completed by the production manager.

The methodology to "Develop Diagnostic Tools to Evaluate the Cause of Declines in Problem Wells" was as follows:

1. Identify responsible parties and their responsibilities for achieving and maintaining optimum well production.

2. Review the sources of data collection.

3. Identify the criteria for wells identified as problem wells.

4. Identify methods to quickly determine the productive potential of a well; Production decline curve analysis, flowing bottom hole pressure analysis, shut-in bottom hole pressure analysis, Inflow Performance Relationship analysis, and economic analysis are specific methods to analyze abnormal production decline that are incorporated into the data collection forms.

5. Develop data collection forms for each production method, i.e., tubing plunger, casing plunger, pumping unit, and swab or flow wells.

Task 7 - Identify Cost Effective Techniques to Solve the Most Frequently Experienced Problems

This task as originally described in the Statement of Work is as follows:

"Through experience in operating stripper wells, identify those techniques employed successfully in correcting problem wells. Develop techniques to quickly estimate production increases, then prepare economics of the proposed work to calculate pay out, rate of return, and profit to investment ratio."

Data Reduction and Methodology

Techniques employed in correcting problem wells incorporate petroleum engineering principals and experience. Specifically, the techniques include production decline curve analysis, flowing bottom hole pressure analysis, shut-in bottom hole pressure analysis, Inflow Performance Relationship analysis, economic analysis, and extensive workover experience. The application of these techniques has been field proven through personal experience and by the observation of other operators. Cost effective techniques require procedures that incorporate systematic data collection and decision tree analysis.

Our research analyzed the 376 well study group and identified 270 wells (72%) that had experienced abnormal production decline in the past five years. Greater than 90% of the abnormal production declines were caused by Fluid Accumulation Problems (45.9%), Gathering System Restrictions (24.0%), and Mechanical Failure (22.6%). It is significant that the majority of the abnormal production declines were due to fluid accumulation problems.

The Decision Tree Triage Form and the Data Collection Forms developed as a result of our research provide a systematic method to evaluate the most common causes of abnormal production declines. The Triage Form focuses on the identification of factors that affect the flowing bottom hole pressure to evaluate the cause of abnormal production declines in stripper gas wells. The Tree Triage Form is divided into three sections, Phase 1 – Identify the Problem Well, Phase 2 – Measure the Problem Well, Phase 3 – Solve the Problem Well. The overall philosophy of the Triage Form begins with the simplest analysis by eliminating the most common problems, and then expanding the analysis as the problem requires. The Data Collection Forms incorporate data from the pumper and the production manager to aid in bottom hole pressure and economic analysis.

Our research refers to the work completed by Vogel whereby "Fluid flow in a reservoir is caused by movement of fluid from a high pressure area to a low pressure area and that fluid flow increases as the differential pressure increases." "Vogel presents an Inflow Performance Relationship, or IPR curve for determining producing rate efficiency based upon the ratio of the well bore pressure to the reservoir pressure".

We previously discussed four economic guidelines to determine the economic benefit of the proposed correction, incremental mcfd production, M$ per mcfd increase ratio, payout in months, and net present value. Incremental production comparison does not necessarily indicate the economic benefit but does provide one method for comparison. The M$ ratio provides the production manager with one benchmark to rank the investment potential of the proposed recommendation. Payout is defined as the cost of the project divided by the monthly income based upon forecasted production increases and current product prices measured in months. Any project with a payout period less than one year would typically proceed without much further analysis required while those projects with longer payouts should be reviewed closer. The calculation of net present value based upon future reserves and cash flow should be considered as the superior method to determine economic benefit over the life of the project.

Therefore, the production manager could then rank all of the investment opportunities available against the capital dollars available based upon the cost of the proposed project, the ratio of invested dollars to production increase, and the payout time of the project. This list of proposed projects and their economic ranking would provide a quick reference list for future proposals that come available.

The methodology to "Identify Cost Effective Techniques to Solve the Most Frequently Experienced Problems" is as follows:

1. Techniques include production decline curve analysis, flowing bottom hole pressure analysis, shut-in bottom hole pressure analysis, Inflow Performance Relationship analysis, economic analysis, and extensive workover experience.
2. Cost effective techniques require procedures that incorporate systematic data collection and decision tree analysis.
3. Determine the most common problems that cause abnormal production decline in stripper gas wells.
4. Develop decision tree and the data collection Forms as a result of our research to provide a systematic method to evaluate the most common causes of abnormal production decline, fluid accumulation.
5. Identify economic guidelines for evaluating proposed remediation strategies: incremental production, M$ per mcfd, payout, and net present value.

Task 8 - Apply Methodology to a Group of Wells Where Recent Problems Have Developed
This task as originally described in the Statement of Work is as follows:
"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."

Data Reduction and Methodology
Twenty-four wells were identified with abnormal production decline from decline curve analysis and Artex Oil Company's monthly "Priority" production monitoring reports. The following wells were reviewed utilizing the Decision Tree Triage Forms and the Data Collection Forms developed as a result of this study to determine the source of the abnormal well decline, the potential for increased production, and the economic benefit.

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

Descriptions of the processes for utilizing the Decision Tree Triage Forms and the Data Collection Forms are provided in Tasks 5, Develop Decision Trees and Task 6, Develop Diagnostic Tools to Evaluate the Cause of Declines in Problem Wells.

Of the 24 well study group with abnormal production decline, 15 wells were determined to be due to fluid accumulation problems, 8 wells were due to mechanical failures, and 1 well was due to gas system restrictions. Note that the majority of the abnormal production declines, or greater than 60%, was attributable to fluid accumulation problems.

A summary of the analysis performed utilizing the Decision Tree Triage Forms and the Data Collection Forms is included as Appendix 12.

The methodology to "Apply Methodology to a Group of Wells Where Recent Problems Have Developed" is as follows:

1. Identify a group of wells with recent abnormal declines from production monitoring reports and decline curve analysis.

2. Complete Phase 1 of the Decision Tree Triage Form verifying that the problem still exists and that there were no problems with the chart integration or gas gathering system integrity.

3. Complete Phase 2 of the Decision Tree Triage Form by providing the pumper with the appropriate Data Collection Form for completion of sections I, II, and III. The production manager then completes sections IV, V, VI, VII, and VIII to provide a solution to the abnormal production decline.

4. Complete Phase 3 of the Decision Tree Form to calculate the economic indicators for each investment opportunity.

5. Evaluate the group of wells to select the most economical candidates based upon incremental production, M$ per mcfd, and payout.

Task 9 - Select the Two Wells with the Greatest Potential for Increase and also having the Most Frequently Occurring Problem

This task as originally described in the Statement of Work is as follows:

"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."

Data Reduction and Methodology

The C. Williams #1 and the Richey Lucille #1 were selected as the two wells with the greatest potential for production increase as well as the most frequently occurring problem, fluid accumulation. The following reviews the analysis utilizing the Decision Tree Triage Form and the Data Collection Form.

C. Williams #1

The C. Williams #1 is a Clinton Sand well which produced through 1 ½" tubing with a tubing plunger at the time of analysis. Abnormal production decline was identified from Artex Oil Company's monthly "Priority" production monitoring reports and the production decline curve.

A Decision Tree Triage Form was prepared for the well. In Phase 1 the production data, decline curve, and associated forecast were reviewed for accuracy. The pumper verified that a production problem existed. The gas sales line showed no unusual integrity problems and there were no problems observed with the chart integration statements. The gas sales metering system for the C. Williams #1, however was unusual. The C. Williams #1 was not measured individually, but was combined with the C. Williams #2 gas production. Gas sales from another well were combined with gas sales from the C. Williams #1 & 2 into a common master meter. The gas sales from the metered well was subtracted from the master meter with the remainder of the gas sales allocated equally between the C. Williams #1 and the C. Williams #2. Since the C. Williams #1 & #2 had separate production meters from the initial completion through 1994, accurate production histories and decline curves had been established for both wells. The C. Williams #1 well had historically been the better of the two wells indicating the allocated production had understated the well's performance. Based upon this information the C. Williams #1 had the greater potential for improvement.

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

The information provided by the pumper showed the well being on three 30 minute production cycles per day at regular intervals. The tubing pressures before each cycle was 220 psi and 110 psi at the end of the cycle. The beginning and ending casing pressures were 240 psi and 200 psi respectively producing into a 35 psi gas gathering system. Production from the C. Williams #1 was estimated at 6 mcf per day and ½ barrel of water per day on this cycle.

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. A review of the well work chronology, see Appendix 13, indicated that the C. Williams #1 was completed in 1973 with perforations from 4,562'-4,672'. The well was initially placed on production through 4,694' of 1 ½" tubing with a tubing plunger. The 1 ½" tubing was reset in 1990 to 4,525' and the tubing plunger was removed. The well was shut in from 1994-1996 due to a shut down of the gas transmission line in the are but was returned to production in 1996 when the 1 ½" tubing was pulled and a casing plunger installed. After unsuccessful attempts to produce the well by casing plunger, 1 ½" tubing was re-installed in 1998 and the well returned to tubing plunger operation

When a typical Clinton Sand decline curve was applied to the historical production data, it was obvious that the well had been under produced since the 1996 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 the temporarily abandoned transmission line. The type curve analysis indicated the well should be producing 12 to 15 mcfd.

A flowing bottom hole pressure of 200 psi and a shut in pressure of 320 psi represents a FBHP to SIBHP ratio of 0.625. Vogel's Inflow Performance Relationship Curve indicated that the C. Williams #1 was producing at 55% of its maximum producing rate. The well should have a maximum production rate of 11 mcfd based on an estimated current producing rate of 6 mcfd.

The estimated actual production was questionable due to the current metering arrangement, however, early time production history indicated this level of production was not unreasonable when an optimum pressure drop was achieved. Pressure information collected through previous service work and current analysis confirmed that optimal pressure drop was not being achieved with current tubing plunger operations. Since neither the tubing plunger or casing plunger had been successful in removing the liquid from the wellbore, a bottom hole pump, rods, and pumping unit were recommended at an estimated cost of $10,000.

Economic analysis for the remediation based upon an incremental increase of 10 mcfd and $3.00 per mcf estimated the payout to be approximately 20 months. The proposed remediation had a 1.0 M$ per Mcfdeq for the purposes of ranking the project with other investment opportunities.

Richey Lucille #1

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

The Richey Lucille #1 was originally completed in 1974 with perforations from 4,668'-4,692'. The well was initially placed on production through 4 ½" casing. The well was subsequently put on pump in 1985. The rods, tubing, and pumping unit were pulled in 1994 and the well converted to casing plunger operation through 1998. In 1998 the casing plunger was pulled and the well was converted to a swab well. Records indicate that in March 2000, 600' of fluid were swabbed from the well.

A Decision Tree Triage Form was prepared for the well. In Phase 1 the production data, decline curve, and associated forecast were reviewed for accuracy. The pumper verified that a problem existed, but the gas system did not appear to have any integrity problems at the time of analysis nor were there any problems observed with the gas metering statements.

In Phase 2, a Swab Well Data Collection Form was provided to the pumper at a weekly production meeting for completion of sections I, II, and III. The form was returned to the production manager the following week.

The information provided by the pumper showed the well was produced twenty-four hours a day, seven days a week. The average flowing casing pressure and gas sales line pressure were equal at 40 psi.

The production manager completed the remainder of the Data Collection Form, sections IV – VII. No estimate was available for the flowing bottom hole pressure since the well was produced through the casing, however, based upon a previous fluid level of 600' noted in a 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. No Vogel IPR analysis was possible since no flowing bottom hole pressure was available.

When a typical Clinton Sand decline curve was applied to the historical production data , it was obvious that the well had been under produced since the 1994 when the rods and tubing were pulled and the well was converted to a swab well. The significant production decrease following the removal of rods and tubing and the gas sales increase when fluid was recovered during swabbing operations indicates the effect of fluid production upon the flowing bottom hole pressure. Production decline curve analysis indicated that the well was capable of at 25 to 30 mcfd, while it presently produced an average of 8 mcfd.

The Richey Lucille #1 was not effectively produced by using a casing plunger to remove wellbore fluids. Swabbing operations confirmed that fluid was still present in well bore during production. Gas production subsequent to swabbing increased production approximately 20%, but the increase could not be sustained. It is obvious that a minimal amount of fluid in the wellbore late in the life of a stripper gas well can have 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.

Preliminary economic analysis for the remediation based upon an incremental increase of 20 mcfd and at $3.00 per mcf indicated a payout of approximately 10 months. The proposed remediation had a 0.9 M$ per Mcfdeq for the purposes of ranking the project with other investment opportunities.

The methodology to "Select the Two Wells with the Greatest Potential for Increase and also having the Most Frequently Occurring Problem" is as follows

1. Review the 24 well study group and economic indicators to select two wells with the greatest potential for increase and also having the most frequently occurring problem.

2. Select the C. Williams #1 and Lucille Richey #1 for remediation based upon the results of the review.

3. Perform the recommended strategy.

4. Monitor the results of the remediation strategy through production monitoring.

Task 10 - Evaluate the Results of the Methodology and the Implemented Procedures
This task as originally described in the Statement of Work is as follows:
"Any decline in production can dramatically affect the economics of a stripper gas well. Document the implementation of the process from the initial evaluation of the production decline curve to the determined cause of the decline. Monitor the results of the work performed on the wells in the field to determine the effectiveness and potential repeatability of the process. Compare the results to those expected as well as those experienced in other wells with similar producing characteristics."

Data Reduction and Methodology:
The following discusses the results of the methodology used to analyze the C. Williams #1 and the Richey Lucille #1 selected as the two wells with potential for production increase and also had the most frequently occurring problem - fluid accumulation. The remediation strategy and preliminary results are also discussed.

C. Williams #1
The C. Williams #1 is a Clinton Sand well that was produced through 1 ½" tubing with a tubing plunger well prior to remediation. 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. Vogel's Inflow Performance Relationship Curve indicated that the C. Williams #1 was producing at 55% of its maximum producing rate with a maximum production rate of 11 mcfd. Decline curve analysis indicated that the well could be capable of at least 10 to 12 mcfd. The gas metering system prior to remediation did not accurately reflect the well's actual production, however, early time production history indicated significant production when optimum pressure drop was achieved. Pressure information collected through previous service work and current analysis confirmed that optimal pressure drop was not being achieved with the current operations. Since neither the tubing plunger or casing plunger had successfully produced the well, the recommended production 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 $10,000. Economic analysis indicated a payout of approximately 11 months based upon an incremental 10 mcfd at $3.00 per mcf. The well had a 1.0 M$ per Mcfdeq for the purposes of ranking the proposed project with other investment opportunities.

Installation of the pumping unit was completed on June 8, 2001. The well is pumped four times per week at four hours per cycle. The point of connection to the gas gathering system was moved eliminating 2000' of pipeline with a separate sales meter installed. Preliminary production results indicate the well produces 38 mcfd and 2 barrels of fluid per day, almost four times greater than predicted, see decline curve in Appendix 14. The positive variance is due somewhat to flush production but may be revealing prior metering and allocation problems. Results of the workover caused a review of the gathering and metering system for problems that were not apparent in the initial evaluation, but also highlight the importance of the historical data and decline curve analysis.

The actual cost for the remediation was $10,954 with an associated payout in 4 months based upon an average 30 mcfd increase at $3.00/mcf. The success of this remediation illustrates the importance of accurate production data, proper metering and pressure monitoring. Further, it also illustrates that the results obtained can be better than the results that were predicted.

Richey Lucille #1

The Richey Lucille #1 is a Clinton Sand well which was produced through 4 ½" casing as a swab well at the time of analysis. Abnormal production decline was identified from Artex Oil Company's monthly "Priority" reports. The well was produced twenty-four hours a day seven days a week. The average flowing casing pressure and gas sales line pressure was equal at 40 psi. 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. Vogel IPR analysis was not possible since flowing bottom hole pressure data was not available, however, production decline curve analysis indicated that the well was capable of 25 to 30 mcfd and was presently producing an average of only 8 mcfd. The Richey Lucille #1 was not successfully produced using a casing plunger to maintain a minimal fluid level in the wellbore. Swabbing operations 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 is obvious that a minimal amount of fluid in the wellbore late in the life of a well has dramatic effect on stripper gas well performance. The recommended production 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. Preliminary economic analysis indicated a payout of approximately 10 months based upon an incremental 20 mcfd at $3.00 per mcf. The well had a 0.9 M$ per Mcfdeq for the purposes of ranking the project with other investment opportunities.

Installation of the pumping unit was completed on April 26, 2001. The well is pumped two times per week at four hours per cycle. Preliminary production results indicate the well is producing 26 mcfd and 3/4 barrels of fluid per day, similar to that predicted by decline curve analysis. See production decline curve in Appendix 16. Results of this remediation illustrate not only the importance of accurate production data but also a complete production history for accurate decline curve analysis.

Actual cost for the remediation was $17,576 with an associated payout in 11 months based upon an average 18 mcfd increase at $3.00/mcf.

The results of the C. Williams #1 and the Lucille Richey #1 are consistent with the results experienced on the remediation of other wells owned and operated by Artex Oil Company.

The methodology to "Evaluate the Results of the Methodology and the Implemented Procedures" is as follows:

1. Summarize the well work chronology for the C. Williams #1 and the Lucille Richey #1
2. Summarize the analysis to determine the recommended remediation strategy.
3. Summarize the remediation strategy performed.
4. Summarize the results of remediation strategy performed.
5. Compare the results of the remediation to those expected and to others with similar producing characteristics.
6. Determine the effectiveness and repeatability of the process.

Task 11 – Deliver Procedure Guide, Summary Report, and Society of Petroleum Engineers Paper

This task as originally described in the Statement of Work is as follows:

"Complete and summarize all statistics and information gathered from the study group of wells. Carefully review the evaluation criteria and diagnostic procedures used to identify and correct wells departing from a normal or consistent decline trend. Prepare all documents to present to the Department of Energy, as well as a technical paper for the Society of Petroleum Engineers (SPE)."

Data Reduction and Methodology

This summary report provides the documentation, support data, and methodologies for the following deliverables;

- Establish a study group of stripper gas wells
- Review and identify problem wells exhibiting abnormal decline
- Categorize individual well problems
- Summarize the frequency of individual well problem
- Develop decision trees
- Develop diagnostic tools to evaluate declines in problem wells
- Identify cost effective techniques to solve the most frequently experienced problems
- Apply methodology to a group of wells where recent problems have developed to identify problem
- Select the two wells with the greatest potential for increase in production and having the most frequently occurring problems
- Evaluate the results of the methodology and the implemented procedures
- Describe the procedure guide

All materials and procedures have been reviewed to provide stripper gas well operators with a consistent methodology to analyze and correct abnormal production decline caused by the most common problems.

A procedure guide has been prepared that details the utilization of the Decision Tree Triage Form, the Alternate Production Decision Form, and the Data Collection Forms.

A presentation of the summary technical report was presented at the National Energy Technology Laboratory in Morgantown West Virginia on September 13, 2001. These materials will also be presented at the 2001 Eastern Regional Society of Petroleum Engineer's Meeting October 18, 2001 in Canton, Ohio. It has also been requested that a presentation of the results of this research will also be made at Petroleum Technology Transfer Council workshops.

Task 12 – Twenty Four Well Study Group Review

Based upon the successful results of the two wells remediated as part of the project and the efficiency of the project to date, additional wells were reviewed for possible inclusion into the study. The status of the wells in the twenty-four well study group were first reviewed to determine if remediations had been completed and if so, the results of the remediations. well as other wells in the database which were currently experiencing abnormal production decline.

Ten additional wells were reviewed as part of this report as follows: E. Carrick #1, M. Pickenpaugh #3, OP Combs #4B, J. McCall #1, JB Bigley #1, Richey Reed #1, John Jenkins #1, Ellis Miller #3, OP Brown 15B, and the Leslie Stevenson #2.

no review is included since no work was completed to date on the following wells: R. Florence #1, R. Krapps #1, Reed #1, R. Krapps #2, W. Fitzgerald #1, A. Larrick #2, Richey Dunkle #1, Dee D. Dunkle #1, OP Christopher #26C, Owen Reed #1, Presdee #1, and the M. Pickenpaugh #4.

E. Carrick #1 Remediation Summary

The E. Carrick #1 is a Clinton Sand well completed in November 1973 that produced through 1 ½" tubing by tubing plunger at the time of analysis. Abnormal production decline was primarily identified by well tender field review, and from monthly production monitoring reports and decline curve analysis. The cause of the abnormal production decline was determined to be a casing leak in the 4 ½" production casing based upon a change in the casing pressure and the detection of a hydrogen sulfide odor. The hydrogen sulfide odor is common with down-hole production casing failures and is often detected when a casing leak occurs.

The well was produced on timed cycles prior to the identification of a casing leak in the 4 ½" production casing with a gas sales line pressure of 130 psi. No estimate was available for the flowing bottom hole pressure due to the hole in the casing, however, a 360 psi shut in pressure was obtained after the workover was complete at 360 psi. Vogel IPR analysis was not possible since no flowing bottom hole pressure data was available. Production decline curve analysis indicated that the well was capable of 30 to 35 mcfd. Previous production operations indicated that minimal fluid was present and that the well could be successfully produced utilizing tubing plunger operation.

The recommended corrective action was to pull the current production string of 1 ½" tubing, clean out the well to total depth, run a packer on 2 7/8" tubing to isolate the casing leak, rerun the 1 ½" tubing as the production string, then return the well to production as a tubing plunger well. Estimated cost for the remediation was $18,000. Preliminary economic analysis indicated a 6-month payout of based upon an incremental 35 mcfd at $3.00 per mcf. The well had a 0.5 M$ per Mcfdeq for the purposes of ranking the project with other investment opportunities.

The proposed remediation was completed on May 15, 2001. The well is produced on (4) 30 minute cycles per day. Preliminary production results indicate the well is producing 45 mcfd and 1/4 barrels of fluid per day, better than that predicted by decline curve analysis due to reduced sales line pressure, see production decline curve in Appendix 17. Results of this remediation illustrate not only the importance of accurate production data but also a complete production history for accurate decline curve analysis.

Actual cost for the remediation was $19,381 with an associated payout in 6 months based upon an average 40 mcfd increase at $3.00/mcf.

M. Pickenpaugh #3 Remediation Summary
The M. Pickenpaugh #3 is a Clinton Sand well completed in December 1983 that produced through 1 ½" tubing on tubing plunger at the time of analysis. Abnormal production decline was identified from monthly production monitoring reports, decline curve analysis, and well tender field review. The preliminary cause of the abnormal production decline was determined to be a casing leak in the 4 ½" production casing based upon a change in the casing pressure and the detection of a hydrogen sulfide odor. The hydrogen sulfide odor is commonly associated with the Big Lime formation in this area and is often detected when a casing leak occurs.

The well produced on (3) 15-minute cycles per day prior to the identification of a casing leak and was performing well with a recent sales line pressure 40 psi due to additional compression. No estimate was available for the flowing bottom hole pressure due to the hole in the casing, however, a 360 psi shut in casing pressure was obtained in May 2001. Vogel IPR analysis was not possible since flowing bottom hole pressure data was not available while production decline curve analysis indicated the well was capable of 10 to 13 mcfd but was presently not producing. Previous production operations indicated that minimal fluid was present and that the well could be successfully produced utilizing tubing plunger operation.

The recommended corrective action was to pull the current production string of 1 ½" tubing, clean out the well to total depth, run a packer on 2 3/8" tubing to isolate the casing leak, then return the well to production as a tubing plunger well. It was assumed that the reservoir could provide sufficient energy to lift the fluid since no annular area would be available for storage. Estimated cost for the remediation was $6,000. Preliminary economic analysis indicated a 5-month payout of based upon an incremental 13 mcfd at $3.00 per mcf. The well had a 0.5 M$ per Mcfdeq for the purposes of ranking the project with other investment opportunities.

The proposed remediation was completed on June 6, 2001. The well is produced on (3) 15-minute cycles per day. Preliminary results indicate the well is producing less than 3 mcfd and little or no fluid due to tubing plunger problems, see production decline curve in Appendix 18. Previous fluid production prior to the casing repair was approximately 2 barrels per week while current production is less than 0.5 barrels per week. Initial analysis indicates that the production problem may be due to insufficient gas supply to sufficiently operate the tubing plunger. Correction will require a swab rig to remove the current fluid in the wellbore and then see if adjusting the production cycles can restore production. Results of this remediation illustrate not only the importance of accurate production data but also a complete production history for accurate decline curve analysis.

Actual cost for the remediation was $9,488 with an associated payout in 34 months based upon an average 3 mcfd increase at $3.00/mcf.

OP Combs #4B Remediation Summary
The OP Combs #4B is a Clinton Sand well completed in August 1971 that produced through 1 ½" tubing on tubing plunger well at the time of analysis. Abnormal production decline was identified from monthly production monitoring reports, decline curve analysis, and primarily

well tender field review. The preliminary cause of the abnormal production decline was determined to be a leak in the 4 ½” production casing at ground level.

Swabbing operations had been unsuccessful in restoring tubing plunger operation due to continued leak in the 4 ½” casing. The well produced on (1) 20 minute cycle per day into a 130 psi gas gathering system prior to the identification of the casing leak. No estimate was available for the flowing bottom hole pressure due to the hole in the casing, however, a 500 psi shut in casing pressure was obtained in December of 1998. Vogel IPR analysis was not possible since flowing bottom hole pressure data was not available. Production decline curve analysis indicated that the well was capable of 10 to 15 mcfd and was presently not producing. Previous production operations indicated that some fluid was present and that converting to pumping unit operation could successfully produce the well.

The recommended corrective action was to pull the current production string of 1 ½” tubing, repair the 4 ½” casing leak at the surface, clean out the well to total depth, then return the well to production as a pumping unit well. Estimated cost for the remediation was $15,000. Preliminary economic analysis indicated a 14-month payout of based upon an incremental 12 mcfd at $3.00 per mcf. The well had a 1.3 M$ per Mcfdeq for the purposes of ranking the project with other investment opportunities.

The proposed remediation was completed on April 27, 2001. The well is produced on (4) 30-minute cycles per day. Preliminary production results indicate the well is producing less than 5 mcfd, see production decline curve in Appendix 19. Initial analysis indicates that the current problem is due to the inadequate pump engine performance. Previous fluid production prior to the casing repair and conversion to pumping unit operations was unavailable while current production was 4 to 6 barrels per week. Results of this remediation illustrate not only the importance of accurate production data but also a complete production history for accurate decline curve analysis.

Actual cost for the remediation was $16,523 with an associated payout in 15 months based upon an average 12 mcfd increase at $3.00/mcf once production is restored.

J. McCall #1 Remediation Summary

The J McCall #1 is a Clinton Sand well completed in February 1980 that was produced through 1 ½” tubing as a tubing plunger well at the time of analysis. Abnormal production decline was identified through decline curve analysis. The preliminary cause of the abnormal production decline was determined to be due to high sales line pressure.

The well was produced on (1) 15 minute cycle per day prior to the identification of a casing leak into a 130 psi gas gathering system. It was estimated that the flowing bottom hole pressure was approximately 250 psi with a 300 psi shut in pressure. Vogel IPR analysis identified the well was only producing at 28% of its maximum potential. Production decline curve analysis indicated that the well was capable of 8 to 10 mcfd. Previous production operations indicated that some fluid was present and that converting to pumping unit operation could successfully produce the well.

The recommended corrective action was to install compression to reduce the line pressure to permit sustained tubing plunger operation. Estimated cost for the remediation was $1,500.

Preliminary economic analysis indicated a 2-month payout of based upon an incremental 9 mcfd at $3.00 per mcf. The well had a 0.2 M$ per Mcfdeq for the purposes of ranking the project with other investment opportunities.

The proposed remediation was completed on April 15, 2001. The well produces on (6) 15-minute cycles per day at 6-10 mcfd, see production decline curve in Appendix 20. Fluid production prior to compression was 1 barrel per week but increased to 3 to 4 barrels per week. Results of this remediation illustrate not only the importance of accurate production data but also a complete production history for accurate decline curve analysis.

Actual cost for the remediation was $1,000 with an associated payout in 4 months based upon an average 4 mcfd increase at $3.00/mcf once production is restored.

J.B. Bigley #1 Remediation Summary
The JB Bigley #1 is a Clinton Sand well completed in June 1978 that was produced through 2 3/8" tubing as a swab well at the time of analysis. Abnormal production decline was identified through decline curve analysis and field review. Swabbing operations had been unsuccessful in maintaining optimal production. The preliminary cause of the abnormal production decline was determined fluid accumulation.

The well was produced 24 hours per day into a 50 psi gas gathering system. No estimate was available for the flowing bottom hole pressure. A shut in pressure was taken on April 4, 2001 showing a reservoir pressure of 360 psi. Vogel IPR analysis was not possible since flowing bottom hole pressure data was not available, however, production decline curve analysis indicated that the well was capable of 7 to 8 mcfd. Previous production operations indicated that some fluid was present and swabbing typically recovered 7 – 10 barrels of fluid.

The recommended corrective action was move in a swab rig to swab the well off and then attempt to produce the well utilizing tubing plunger operation. Estimated cost for the remediation was $2,000. Preliminary economic analysis indicated a 5-month payout of based upon an incremental 5 mcfd at $3.00 per mcf. The well had a 0.4 M$ per Mcfdeq for the purposes of ranking the project with other investment opportunities.

The proposed remediation was completed on April 23, 2001. The well currently produces on (1) 15 minute cycle per day at 4-5 mcfd, see production decline curve in Appendix 21. Prior to the remediation fluid production was limited to those times the well was swabbed, however, little fluid is produced during current tubing plunger operation. Results of this remediation illustrate not only the importance of accurate production data but also a complete production history for accurate decline curve analysis.

Actual cost for the remediation was $1,500 with an associated payout in 4 months based upon an average 5 mcfd increase at $3.00/mcf once production is restored.

Richey Reed #1 Remediation Summary
The Richey Reed #1 is a Clinton Sand well completed in February 1974 that was produced through 4 ½"casing as a swab well at the time of analysis. The well was produced by pumping unit from initial completion until 1985 when it was converted to a casing swab well. Abnormal production decline was identified through decline curve analysis, monthly production monitoring

reports, and field review. The preliminary cause of the abnormal production decline was determined to be a fluid accumulation.

Decline curve analysis indicated that swabbing operations had historically been somewhat successful in restoring production, however, maximum production was not sustained due to fluid influx as evidenced by decreased production after swabbing. Swabbing operations are required approximately every 10 months to sustain production with declining reservoir pressure. The well was produced 24 hours per day into a 40 psi gas gathering system. No flowing bottom hole pressure was available, however a March 2000 swab report recorded a 500' fluid level indicating a shut in bottom hole pressure equal to 200 psi. The shut in pressure was consistent with other wells of this vintage. Vogel IPR analysis was not possible since flowing bottom hole pressure data was not available while production decline curve analysis indicated that the well was capable of 7 to 8 mcfd. Previous production operations indicated that some fluid was present and swabbing typically recovered 7 – 10 barrels of fluid.

The recommended corrective action was to move in a swab rig, swab the well off, then continue to produce the well as a swab well. Estimated cost for the remediation was $1,000. Preliminary economic analysis indicated a 4-month payout of based upon an incremental 3 mcfd at $3.00 per mcf. The well had a 0.3 M$ per Mcfdeq for the purposes of ranking the project with other investment opportunities.

The proposed remediation was completed on May 30, 2001. The well currently produces on 24 hours 7 days per week at 10-12 mcfd, see production decline curve in Appendix 22. The well was maintained as a swab well, therefore fluid is only produced during swabbing operation. Results of this remediation illustrate not only the importance of accurate production data but also a complete production history for accurate decline curve analysis. Additional analysis may indicate that swabbing operations may not result in the most economical recovery of the remaining reserves.

Actual cost for the remediation was $552 with an associated payout in 2 months based upon an average 5 mcfd increase at $3.00/mcf once production is restored.

John Jenkins #1 Remediation Summary

The John Jenkins #1 is a Clinton Sand well completed in February 1971 that was produced through 1 ½" tubing as a tubing plunger well at the time of analysis. The well was produced through 1 ½" tubing since initial completion. Abnormal production decline was identified through decline curve analysis, Priority production monitoring reports, and field review. The preliminary cause of the abnormal production decline was determined to be a fluid accumulation.

Decline curve analysis indicated that tubing plunger operations had historically been successful at producing the well through 1986 but the well has struggled since 1986 for continuous production. The well was produced on (2) 15-minute cycles per day into a 40 psi gas gathering system. A recent flowing bottom hole pressure of 250 psi and a 360 psi shut in bottom hole pressure were available from the well tender. Furthermore, a fluid level of 700'in 2000 indicated a shut in bottom hole pressure equal to 304 psi. Vogel IPR analysis indicated a flowing bottom hole pressure to shut in bottom hole pressure ratio of 0.69, or that the well was producing at approximately 48% of its maximum rate. Decline curve analysis indicated that the well was capable of 5 to 7 mcfd.

The recommended corrective action was to move in a swab rig, swab the well off, then adjust the production cycles to effectively produce the well with tubing plunger operations. Estimated cost for the remediation was $1,000. Preliminary economic analysis indicated a 4-month payout of based upon an incremental 3 mcfd at $3.00 per mcf. The well had a 0.3 M$ per Mcfdeq for the purposes of ranking the project with other investment opportunities.

The proposed remediation was completed on April 26, 2001. The well currently produces on (2) 15-minute cycles per day at 4-5 mcfd, see production decline curve in Appendix 23. The well was maintained as a tubing plunger well and produces ½ barrels of fluid per week. Results of this remediation illustrate the importance of accurate production data, complete production history for accurate decline curve analysis, and good well records. Additional analysis may indicate that tubing plunger operations may not be sufficient for the continued operation of the well.

Actual cost for the remediation was $571 with an associated payout in 2 months based upon an average 5 mcfd increase at $3.00/mcf once production is restored.

Ellis Miller #3 Remediation Summary

The Ellis Miller #3 is a Clinton Sand well completed in March 1994 that was produced through 4 1/2" casing as a swab well at the time of analysis. The well was produced through 2 3/8" tubing from the time of initial completion through 1998 when the tubing was pulled. Abnormal production decline was identified through decline curve analysis, Priority production monitoring reports, and field review. The preliminary cause of the abnormal production decline was determined to be a fluid accumulation.

Decline curve analysis indicated that the well has experienced abnormal decline since the tubing was pulled. Swabbing operations have only produced temporary production increases. The well was produced 24 hours per day into a 60 psi gas gathering system. No fluid level was available from swabbing reports to determine a shut in or flowing bottom hole pressure, however, a January 2001 showed an overnight potential immediately after swabbing of 40 mcfd. No Vogel IPR analysis was possible since neither flowing or shut in bottom hole pressure were available. Decline curve analysis indicated that the well was capable of 15 to 20 mcfd.

The recommended corrective action was to move in a service rig, clean the well out to bottom, then run tubing and rods to convert the well to pumping unit operation. Estimated cost for the remediation was $18,000. Preliminary economic analysis indicated a 20-month payout of based upon an incremental 10 mcfd at $3.00 per mcf. The well had a 0.3 M$ per Mcfdeq for the purposes of ranking the project with other investment opportunities.

The proposed remediation was not completed, however, the well was swabbed again in May 2001 with similar results to previous swabbing operations. The well continues to produce 24 hours 7 days per week at 10 mcfd, see production decline curve in Appendix 24. The well was maintained as a swab well and therefore fluid production is limited to those times when the well is swabbed. Results of this remediation illustrate the importance of accurate production data, complete production history for accurate decline curve analysis, and good well records. Additional analysis may indicate that swab operations may not be resulting in the most economically efficient production of the well.

Actual cost for the remediation was $1,315 with an associated payout in 5 months based upon an average 3 mcfd increase at $3.00/mcf.

OP Brown #15B Remediation Summary

The OP Brown 15 B is a Clinton Sand well completed in October 1972 that was produced through 2 3/8" tubing as a tubing plunger well at the time of analysis. The well was produced on tubing plunger since completion. Abnormal production decline was identified from monthly production monitoring reports and decline curve analysis. The preliminary cause of the abnormal production decline was determined to be a leak in the 4 ½" production casing at ground level.

The well was produced on cycles prior to the identification of a surface casing leak. The average flowing casing pressure and gas sales line pressure was equal at 40 psi. No estimate was available for the flowing bottom hole pressure due to the hole in the casing, however, a 360 psi shut in pressure was obtained after the workover was complete at 360 psi. Vogel IPR analysis was not possible since flowing bottom hole pressure data was not available, however, production decline curve analysis indicated that the well was capable of 10 to 15 mcfd and was presently not producing. Previous production operations indicated that minimal fluid was present and that the well could be successfully produced utilizing tubing plunger operation.

The recommended corrective action was to pull the current production string of 2 3/8" tubing, repair the surface casing leak, then run 1 ½" tubing as the production string. Estimated cost for the remediation was $5,000. Preliminary economic analysis indicated a 9-month payout of based upon an incremental 6 mcfd at $3.00 per mcf. The well had a 0.8 M$ per Mcfdeq for the purposes of ranking the project with other investment opportunities.

The workover as previously described was completed on May 15, 2001. The well is produced on (8) 15-minute cycles per day. Preliminary production results indicate the well is producing 45 mcfd and 1/4 barrels of fluid per day, better than that predicted by decline curve analysis due to the lower line pressure, see production decline curve in Appendix 25. Vogel analysis based upon current flowing and shut in bottom hole pressure information indicates that the well is producing at 85% of its maximum production. Results of this remediation illustrate not only the importance of accurate production data but also a complete production history for accurate decline curve analysis.

Actual cost for the remediation was $1,825 due to the tubing exchange with an associated payout in 4 months based upon an average 5 mcfd increase at $3.00/mcf.

L. Stevenson #1 Remediation Summary

The L. Stevenson #1 is a Clinton Sand well completed in February 1974 that was produced through 4 1/2" casing as a swab well at the time of analysis. The well was produced as a pumping well through 1992 when the well was converted to swab well operation. Abnormal production decline was identified through decline curve analysis, monthly production monitoring reports, and field review.

Decline curve analysis indicated that the well has experienced abnormal decline since 1982. Occasional swabbing operations have only produced temporary production increases. The well was produced 24 hours per day into a 60-psi gas gathering system. No fluid level was available from swabbing reports to determine a shut in or flowing bottom hole pressure. No Vogel IPR analysis was possible since neither flowing or shut in bottom hole pressure were available. Decline curve analysis indicated that the well was capable of 8 to 10 mcfd.

The recommended corrective action was to move in a service rig, clean the well out to bottom, then run tubing and rods to return the well to pumping unit operation. Estimated cost for the remediation was $18,000. Preliminary economic analysis indicated a 66-month payout of based upon an incremental 3 mcfd at $3.00 per mcf. The well had a 6.0 M$ per Mcfdeq for the purposes of ranking the project with other investment opportunities.

The proposed remediation was not completed due to the economic evaluation; however, the well was swabbed again in May 2001 with similar results to previous swabbing operations. The well continues to produce 24 hours 7 days per week at 5 to 6 mcfd, see production decline curve in Appendix 26. The well is maintained as a swab well and therefore fluid production is limited to those times when the well is swabbed. Results of this remediation illustrate the importance of accurate production data, complete production history for accurate decline curve analysis, and complete well records. Nominal production results were observed immediately after completing swab operations.

Actual cost for the remediation was $550 with an associated payout in 5 months based upon an average 3 mcfd increase at $2.00/mcf.

Task 13 –Additional Two Well Remediation Program

Two additional wells were selected for process verification and cost sharing that had been identified from production monitoring reports and decline curve analysis as having experienced abnormal production decline.

The two wells that were not a part of the twenty four well study group but were selected for remediation and cost share were the Aron Woodford #1 and the. Hughes Stiles #1

Aron Woodford #1 Remediation Summary

The Aron Woodford #1 is a Clinton Sand well completed in November 1974 that was produced through 1 ½" tubing on tubing plunger well at the time of analysis. The well was produced on tubing plunger since completion. A complete well work chronology is provided in Attachment 27. Abnormal production decline was identified from monthly production monitoring reports and decline curve analysis. The preliminary cause of the abnormal production decline was determined to be fluid accumulation.

The well was produced on (4) 15-minute cycles at 4 to 5 mcfd with a beginning and ending tubing pressure of 105 and 85 respectively. The associated beginning and ending casing pressures are 135 and 100 psi respectively with a gas sales line pressure equal to 50 psi. A flowing bottom hole pressure was assumed to be 100 psi and a shut in casing pressure of 360 psi was observed in March 1997. Vogel IPR analysis based upon this information showed a flowing bottom hole pressure to shut in bottom hole pressure ratio of 0.27 indicating that the well was performing at approximately 85% of its maximum rate. Production decline curve analysis indicated that the well had historically been under-produced and should be capable of 8 to 10 mcfd and was presently not producing. Previous production operations indicated that the well produced 1 to 2 barrels of fluid per week and that the well would not be able to be produced to its economic life utilizing tubing plunger operation due to domestic gas usage.

The recommended corrective action was to pull and inspect the current production string of 1 1/2" tubing, clean out to total depth, rerun the 1 ½" tubing with the seating nipple at 5,780', run rods and pump, then set a pumping unit. Estimated cost for the remediation was $10,000. Preliminary economic analysis indicated a 22-month payout of based upon an incremental 5 mcfd at $3.00 per mcf. The well had a 2.0 M$ per Mcfdeq for the purposes of ranking the project with other investment opportunities.

The workover as previously described was completed on December 6, 2001. The well is produced on (4) 120-minute cycles per day with preliminary production results indicating the well is producing 15 mcfd and 1 barrel of fluid per day, see production decline curve in Appendix 28. Results of this remediation illustrate not only the importance of accurate production data but also a complete production history for accurate decline curve analysis.

Actual cost for the remediation was $13,927 with an associated payout in 15 months based upon an average 10 mcfd increase at $3.00/mcf.

Hughs Stiles #1 Remediation Summary
The Hughes Stiles #1 is a Clinton Sand well completed in November 1973 that was produced through 1 1/2" tubing as a tubing plunger well at the time of analysis. The well was produced on tubing plunger since completion. A complete well work chronology is provided in Attachment 29. Abnormal production decline was identified from monthly production monitoring reports and decline curve analysis. The preliminary cause of the abnormal production decline was determined to be fluid accumulation.

The well was produced on (12) 12-minute cycles at 11 - 12 mcfd into a 60-psi gas gathering system. The ending cycle tubing and casing pressures were 75 and 140 psi respectively. No estimate was available for the shut-in bottom hole pressure. Vogel IPR analysis was not possible since a shut in bottom hole pressure data was not available, however, an estimate of 300 psi shut in pressure would indicate that the well is producing at 74% of its maximum capacity. Production decline curve analysis indicated that the well was capable of 18 to 20 mcfd while presently producing at 11 to 12 mcfd. Previous production operations indicated that tubing plunger operation would not be capable of producing the well to its ultimate economic recovery due to domestic gas usage, therefore the installation of a pumping unit would be required.

The recommended corrective action was to pull and inspect the current production string of 1 ½"" tubing, clean out the well to total depth, rerun the 1 ½" tubing with seating nipple set at 5,480', run rods and pump, set pumping unit, return well to production. Estimated cost for the remediation was $10,000. Preliminary economic analysis indicated a 14-month payout of based upon an incremental 8 mcfd at $3.00 per mcf. The well had a 1.25 M$ per Mcfdeq for the purposes of ranking the project with other investment opportunities.

The workover as previously described was completed on May 15, 2001. The well is produced on (1) 60-minute cycle per day with preliminary results indications that the well is producing 20 mcfd and 2 barrels of fluid per week, see production decline curve in Appendix 30. Results of this remediation illustrate not only the importance of accurate production data but also a complete production history for accurate decline curve analysis.

Actual cost for the remediation was $18048 due to the tubing exchange with an associated payout in 25 months based upon an average 8 mcfd increase at $3.00/mcf.

Conclusion

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

Results of this research indicate that 270 of the 376 wells reviewed or 70% exhibited abnormal production decline during the past five years. Once the cause of each abnormal production was categorized, fluid accumulation problems accounted for 46% of all the problems, while gathering system restrictions and mechanical failures accounted for 24% and 23 % respectively. This analysis indicates that many stripper gas wells do not experience abnormal production due to reservoir damage, precipitate plugging or reservoir depletion as originally supposed, but rather from failure to reduce the flowing bottom hole producing pressure to maximize production. Fluid accumulation problems restrict maximum production by increasing flowing bottom hole pressure.

The following observations were made during the course of this study. A graphical representation of the complete production history is important for abnormal production decline analysis and should be shared with pumper. All gas, oil, and water volumes should be included as part of the production history. Individual metering or production measuring should be employed whenever possible to clearly identify individual well producing characteristics. In lieu of individual metering, periodic testing of individual wells should be completed for proper production allocation. Well work and chronological histories are very helpful in abnormal production decline analysis. Pressures and volume information in well file or on well servicing tickets are also very helpful in problem well analysis and should be summarized and shared with the pumper. Flowing bottom hole pressures and shut-in pressures for each well should be obtained annually for determining reservoir production efficiency.

The low profitability nature of stripper gas well production, specifically marginal gas well production, limits the amount of time and money available to maximize production, therefore, the production manager must minimize the number of problem wells in day-to-day operations and the amount of time assembling the data and analyzing the causes of abnormal well declines. Through the consistent collection and analysis of data, the production manager and the pumper can keep many stripper wells that are close to the economic limit from becoming problem wells and then be able to analyze those that experience abnormal production decline.

Decision trees and data collection forms provide a systematic methodology to collect and analyze the data for abnormal production decline analysis. A Decision Tree Triage Form was developed with the philosophy to begin with the simplest analysis to eliminate the most common problems, and then expand the analysis as the problem requires. Specific data collection forms for the most common production methods were developed to systematically analyze information available to most operators for the cause of abnormal production decline. Finally, an Alternative Production Method Decision Form was developed to provide a methodology to evaluate the economic benefit of the potential application of various production methods.

A small group of wells recently experiencing abnormal production decline were analyzed using the methodologies, decision trees, and data collection forms developed as a result of this research and then ranked to select two wells for remediation with the greatest potential for production increase and also had the most frequently occurring problem, fluid accumulation.

The preliminary results of the remediations indicate that the methodologies and techniques developed are practical and suitable for most operators based upon data commonly available. The decision trees, data collection sheets, and economic techniques were refined and incorporated into a procedure guide to provide operators with a methodology to analyze and correct abnormal production decline in stripper gas wells. The systematic methodologies and techniques developed should increase the efficiency of problem assessment and implementation of solutions for stripper gas wells.

References

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List of Acronyms and Abbreviations

bbl	Barrel
bbls	Barrels
bopd	Barrels of oil per day
bwpd	Barrels of water per day
DOL	Days On Line
FBHP	Flowing bottom hole pressure
Mcf	Thousand standard cubic feet
Mcfd	Thousand standard cubic feet per day
Mcfdeq	Thousand standard cubic feet per day equivalent
Mcfw	Thousand standard cubic feet per week
Mcfm	Thousand standard cubic feet per month
Psi	Pounds per square inch
SIBHP	Shut in bottom hole pressure

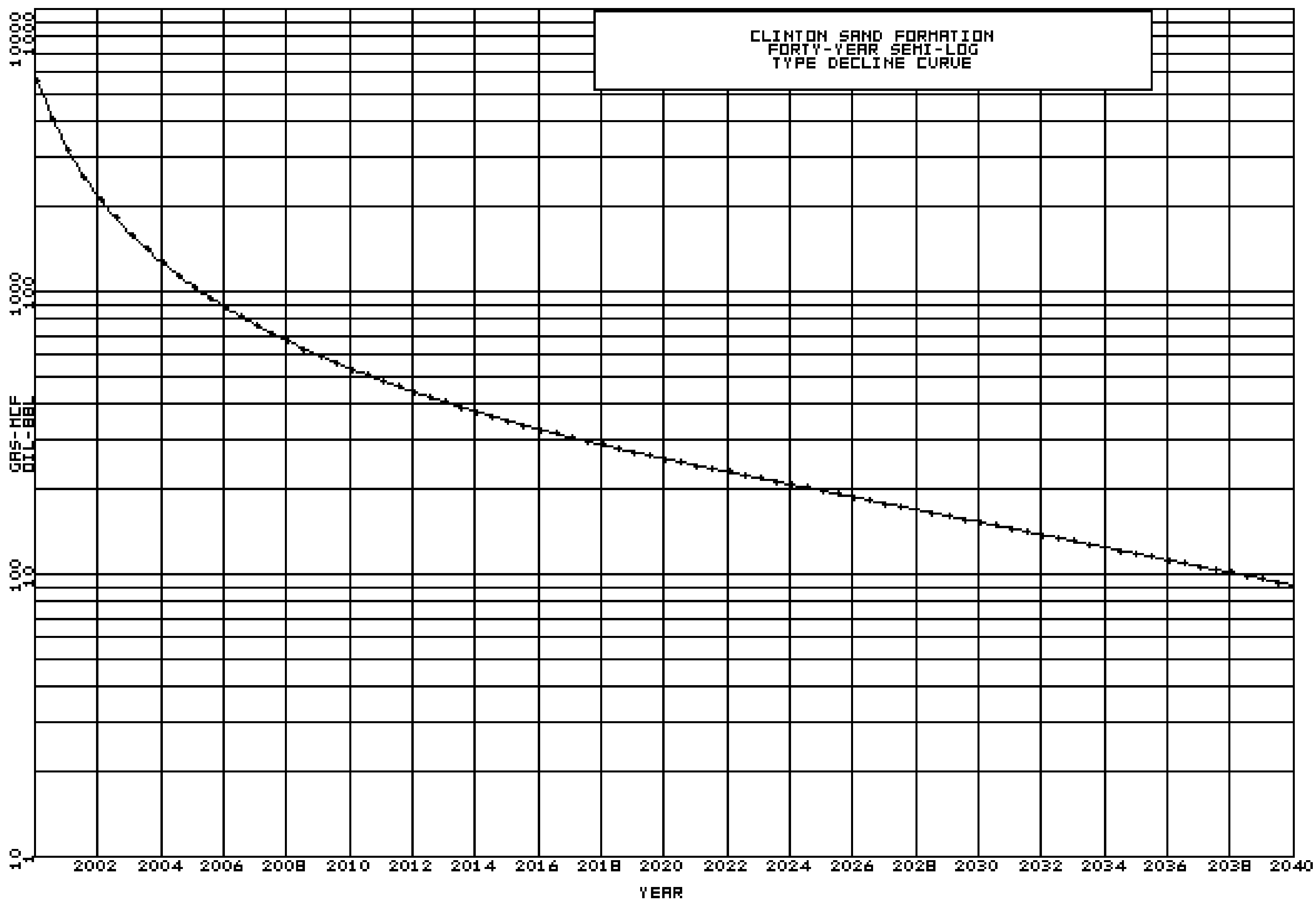
Appendices

Appendix 1	Sample ARIES Semi-Log Production Decline Curve Plot, Barstow #3
Appendix 2	Forty-Year Clinton Sandstone Semi-Log Type Decline Curve
Appendix 3	Decision Tree Triage Form
Appendix 4	Tubing Plunger Data Collection Form
Appendix 5	Casing Plunger Data Collection Form
Appendix 6	Pumping Unit Data Collection Form
Appendix 7	Swab or Flow Well Data Collection Form
Appendix 8	Alternative Production Method Decision Form
Appendix 9	Sample Weekly Production Report
Appendix 10	Sample Monthly "Priority" Report
Appendix 11	Vogel Inflow Performance Relationship Chart
Appendix 12	Twenty-Four Well Study Group Analysis Summary
Appendix 13	C. Williams #1 Well Work Chronology
Appendix 14	C. Williams #1 Production Decline Curve
Appendix 15	Lucille Richey #1 Well Work Summary
Appendix 16	Lucille Richey #1 Production Decline Curve
Appendix 17	E. Carrick #1 Production Decline Curve
Appendix 18	M. Pickenpaugh #1 Production Decline Curve
Appendix 19	OP Combs #4B Production Decline Curve
Appendix 20	J. McCall #1 Production Decline Curve
Appendix 21	JB Bigley #1 Production Decline Curve
Appendix 22	Richey Reed #1 Production Decline Curve
Appendix 23	John Jenkins #1 Production Decline Curve
Appendix 24	Ellis Miller #3 Production Decline Curve
Appendix 25	OP Brown #15B Production Decline Curve
Appendix 26	Leslie Stevenson #2 Production Decline Curve
Appendix 27	Aron Woodford #1 Well Work Summary
Appendix 28	Aron Woodford #1 Production Decline Curve
Appendix 29	Hughes Stiles #1 Well Work Summary
Appendix 30	Hughes Stiles #1 Production Decline Curve

Appendix 1


ARTEX OIL COMPANY
LEASE: BARSTOW #3-LPU
OPERATOR: ARTEX OIL COMPANY
PERMIT: 34-059-2-3696
GUERNSEY
OH
OIL-BBL
GAS-MCF
GAS-MCF
OIL-BBL
10000
1000
1000
100
100
10
10
1
1988 1990 1992 1994 1996 1998 2000 2002 2004 2006 2008 2010 2012 2014 2016 2018 2020 2022 2024 2026
YEAR

Appendix 2


CLINTON SAND FORMATION
FORTY-YEAR SEMI-LOG
TYPE DECLINE CURVE
GAS-MCF
OIL-BBL
10000
1000
1000
100
100
10
10
1
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
YEAR

Appendix 3

Stripper Gas Well
Decision Tree Triage Form
For
Abnormal Production Decline Analysis

Date of Analysis ______________________
Lease Name and Well Number ______________________
Well ID Number ______________________
Production Method ______________________

Step No.	Phase I: Identify the Problem Well	Comment
1.	Review Production Data, Decline Curve, and Forecast	______________
2.	Verify with Pumper that Problem Still Exists	______________
3.	Verify Metering Accuracy	______________
4.	Verify Gas Gathering System Integrity	______________
	Phase II: Measure the Problem Well	
5.	Complete Data Collection Form to Analyze Problem Well	______________
	Phase III: Solve the Problem Well	
6.	Complete Alternative Production Method Decision Form	______________
7.	Complete Proposed Well Work	______________
8.	Review Well to Shut-In, Sell, or Plug and Abandon	______________
9.	No Further Analysis Required, Continue to Produce, Well Cannot be Economically Remediated	______________

Comments

____
____
____
____
____

Appendix 4

Stripper Gas Well
Data Collection Form for Problem Well Analysis
Production Method - Tubing Plunger, TPL

Lease Name and Well No: ________________________________
Date: ________________

Sections I-III for Field Completion

I. Well Information

Producing Formation(s)	______________	
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	Yes / No	

II. Current Daily Production Rate

Oil, Bbl Oil per Day	_____	BOPD
Gas, Mcf per Day	_____	MCFD
Water, Bbl Water per Day	_____	BWPD

III. Comments and Recommendations

____
____
____
____
____

Sections IV-VIII for Office Completion

IV. Analytical Data

Perforated Interval(s)	_________________	
Casing Size	_________________	In
Tubing Size	_________________	In
Tubing 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 Inflow Performance Relationship Analysis

Ratio of FBHP/SIBHP _________________
Estimated Maximum Production Rate ______ BOPD_____MCFD

VI. Forecasted Rates of Production by Current Production Method

Oil, Bbl Oil per Day	_____	BOPD
Gas, Mcf per Day	_____	MCFD
Water, Bbl Water per Day	_____	BWPD

VII. Date and Description of Last Well Work

____
____

VIII. Comments and Recommendations

____
____
____
____
____

Appendix 5

Stripper Gas Well
Data Collection Form for Problem Well Analysis
Production Method - Casing Plunger, CPL

Sections I-III for Field Completion

I. Well Information

Producing Formation(s)	________	
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	Yes / No	
Last Fluid Level Shot: Date/Depth	____/____	Ft

II. Current Daily Production Rate

Oil, Bbl Oil per Day	______	BOPD
Gas, Mcf per Day	______	MCFD
Water, Bbl Water per Day	______	BWPD

III. Comments and Recommendations

____
____
____
____
____

Lease Name and Well No: ______________________________
Date: ________________

Sections IV-VIII for Office Completion

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 Inflow Performance Relationship Analysis

Ratio of FBHP/SIBHP ________

Estimated Maximum Production Rate _____ BOPD_____MCFD

VI. Forecasted Rates of Production by Current Production Method

Oil, Bbl Oil per Day	______	BOPD
Gas, Mcf per Day	______	MCFD
Water, Bbl Water per Day	______	BWPD

VII. Date and Description of Last Well Work

____
____

VIII. Comments and Recommendations

____
____
____
____
____

Appendix 6

Stripper Gas Well
Data Collection Form for Problem Well Analysis
Production Method - Pumping Unit Well, PJEM or PJGE

Lease Name and Well No: ______________________________
Date: _________________

Sections I-III for Field Completion

I. 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. Current Daily Production Rate

Oil, Bbl Oil per Day ______BOPD
Gas, Mcf per Day ______MCFD
Water, Bbl Water per Day ______BWPD

III. Comments and Recommendations

____
____
____
____

Sections IV-VIII for Office Completion

IV. Analytical Data

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

V. Vogel Inflow Performance Relationship Analysis

Ratio of FBHP/SIBHP ________________
Estimated Maximum Production Rate _____ BOPD _____MCFD

VI. Forecasted Rates of Production by Current Production Method

Oil, Bbl Oil per Day _____BOPD
Gas, Mcf per Day _____MCFD
Water, Bbl Water per Day _____BWPD

VII. Date and Description of Last Well Work

____

VIII. Comments and Recommendations

____
____
____
____

Appendix 7

Stripper Gas Well
Data Collection Form for Problem Well Analysis
Production Method - Swab Well, SWB or Flowing Well, FLW

Sections I-III for Field Completion

I. Well Information

Producing Formation(s)	________	
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

II. Current Daily Production Rate

Oil, Bbl Oil per Day	_____	BOPD
Gas, Mcf per Day	_____	MCFD
Water, Bbl Water per Day	_____	BWPD

III. Comments and Recommendations

____
____
____
____
____
____

Lease Name and Well No: ______________________________
Date: ________________

Sections IV-VIII for Office Completion

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 Inflow Performance Relationship Analysis

Ratio of FBHP/SIBHP ________________

Estimated Maximum Production Rate_____ BOPD_____ MCFD

VI. Forecasted Rates of Production by Current Production Method

Oil, Bbl Oil per Day	_____	BOPD
Gas, Mcf per Day	_____	MCFD
Water, Bbl Water per Day	_____	BWPD

VII. Date and Description of Last Well Work

____
____

VIII. Comments and Recommendations

____
____
____
____
____
____

Appendix 8

Stripper Gas Well

Alternative Production Method Decision Form

I. Lease Name and Well Number ______________________________
Current Production Method ______________________________

II. Maximum Flow Rate Predicted by Vogel Inflow Performance Relationship Analysis
Ratio of FBHP/SIBHP ______________________________
Estimated Maximum Production Rate ____ Bopd ____ Mcfd ____Mcfeq

III. Alternative Production Method	Forecasted Rates of Production by Production Method	Cost of Alternative Production Method	Economic Analysis Summary M$/Mcfeqd	Payout	NPV
Swab or Flow Well	____ Bopd ____ Mcfd ____Mcfeq	$__________	_______	_______	_______
Tubing Plunger	____ Bopd ____ Mcfd ____Mcfeq	$__________	_______	_______	_______
Casing Plunger	____ Bopd ____ Mcfd ____Mcfeq	$__________	_______	_______	_______
Pumping Unit	____ Bopd ____ Mcfd ____Mcfeq	$__________	_______	_______	_______
Compression Installation	____ Bopd ____ Mcfd ____Mcfeq	$__________	_______	_______	_______
Pipeline/Meter Installation	____ Bopd ____ Mcfd ____Mcfeq	$__________	_______	_______	_______
Other ____________	____ Bopd ____ Mcfd ____Mcfeq	$__________	_______	_______	_______

IV. Comments and Recommendation

____
____
____
____

While M$ per mcfeqd and payout measured in months are good economic indicators to compare alternatives, the calculation of a Net Present Value, NPV, based upon future reserves and cash flow should be considered as the superior method for determining economic benefit.

Appendix 9

Sample Weekly Pumper Production Report

Pumper – Marcus Toth **Artex Oil Company** **231 Third Street, Marietta, Ohio 45750** **740-373-3313**

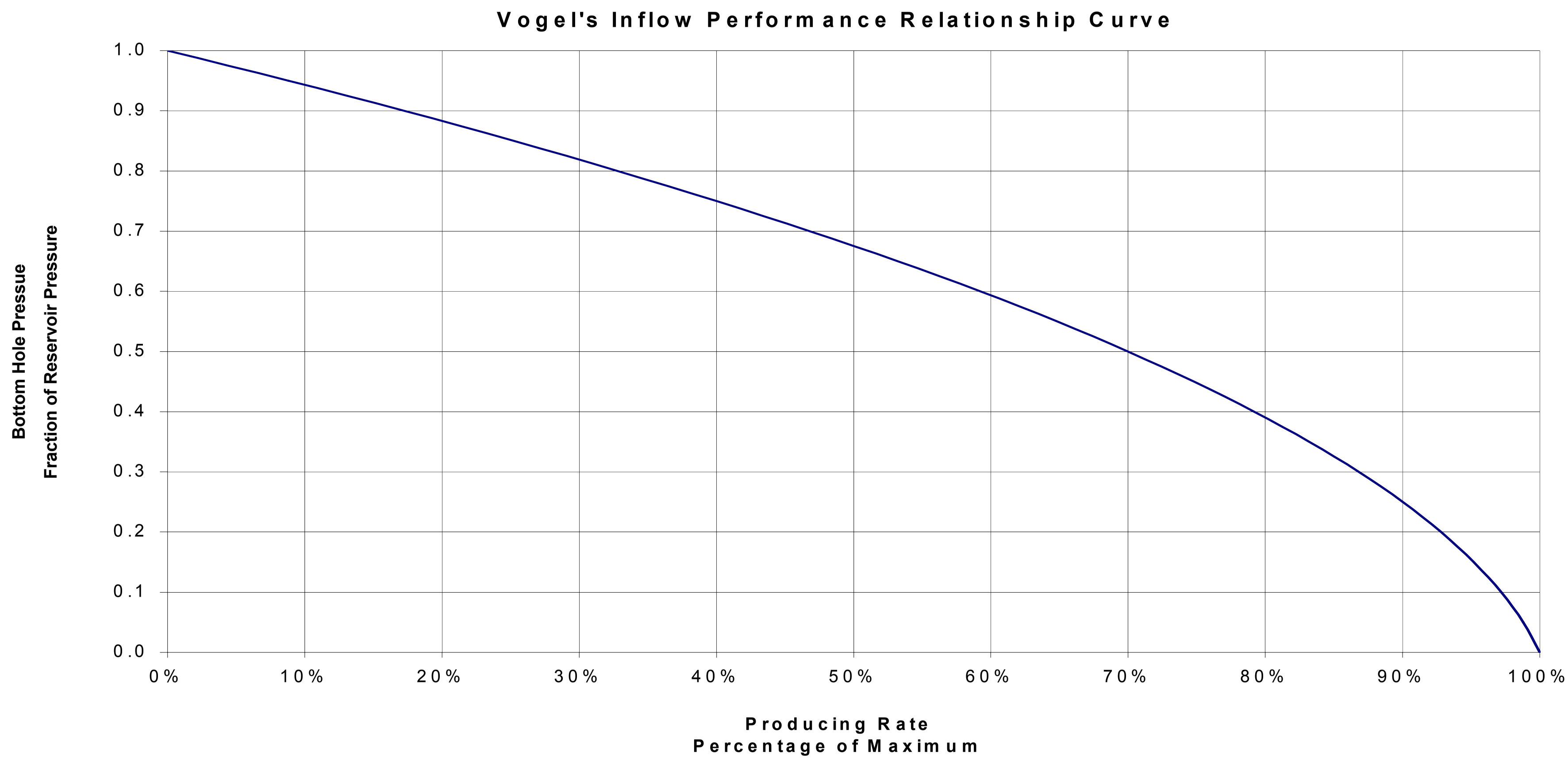
Well Name	Beg Prod	End Prod	Mcfd Prod	Mcfw Prod	Oil Bbls	Water Bbls	DOL Prod	Oil Shipped Bbls	Oil Shipped Date	Tank Beg	Tank End	Meter Size	Comments
E. Carrick #1	6-6	6-13	7	49	0.84		7			6-8	6-9	1/8	
R. Florence #1	6-6	6-13	10	70	0.84		7			8-5	8-6	1/4	
M. Pickenpaugh #3	6-6	6-13	15	105	0		7					1/2	
OP Combs #4B	6-6	6-13	10	70	0		7					1/4	
Reed #1	6-6	6-13	12	84	0		7					1/4	
W. Fitzgerald #1	6-6	6-13	16	112	4.56		7			6-9	7-1	1/4	
J. McCall #1	6-6	6-13	20	140	0		7					1/4	
R. Krapps #2	6-6	6-13	50	350	0		7					3/4	
A. Larrick #1	6-6	6-13	45	315	0		7					3/4	
Richey Dunkle #1	6-6	6-13	35	245	0		7					1/2	
Richey Lucille #1	6-6	6-13	25	175	26.22		7			5-0	6-11	1/4	
JB Bigley #1	6-6	6-13	20	140	0		7					1/4	
Dee D. Dunkle #1	6-6	6-13	15	105	0		7					1/4	
Richey Reed #1	6-6	6-13	20	140	0		7					1/4	
OP Christopher #26C	6-6	6-13	35	245	0		7					3/4	
Owen Reed #1	6-6	6-13	25	175	5.70		7			7-8	8-1	1/4	
C. Williams #1	6-6	6-13	20	140	0		7					1/4	
Presdee #1	6-6	6-13	45	315	0		7					3/4	
M. Pickenpaugh #4	6-6	6-13	35	245	0		7					1/2	
John Jenkins #1	6-6	6-13	15	105	6.04		7	94.62		8-4	8-7	1/4	
Ellis Miller #3	6-6	6-13	10	70	0		7					1/4	
OP Brown #15B	6-6	6-13	5	35	0		7					1/8	
L. Stephenson #2	6-6	6-13	15	105	0		7					1/4	

Appendix 10

Priority Production Monitoring Report
Evaluation for Production Month of June 2001

Well ID	Well Name	Pumper	Producing Method	Actual Prod Mcfm	Actual Prod Bopm	Forecasted Prod Mcfm	Forecasted Prod Bopm	Prod Variance Mcfm	Prod Variance Bopm	Action/Date/Comment
21151	E. Carrick #1	MT	TPL	120	2	125	1	-5	1	
21152	R. Florence #1	MT	TPL	125	0	125	0	0	0	
21153	R. Krapps #1	MT	TPL	130	0	125	0	5	0	
21154	M. Pickenpaugh #3	MT	TPL	100	0	85	0	15	0	
21155	OP Combs #4B	MT	TPL	200	0	150	0	50	0	
21156	Reed #1	MT	SWB	150	0	125	0	25	0	
21157	W. Fitzgerald #1	MT	TPL	175	5	200	6	-25	-1	
21158	J. McCall #1	MT	TPL	225	0	250	0	-25	0	
21158	R. Krapps #2	MT	TPL	275	0	300	0	-25	0	
21159	A. Larrick #1	MT	SWB	175	10	200	12	-25	-2	
21160	Richey Dunkle #1	MT	SWB	125	0	100	0	25	0	
21161	Richey Lucille #1	MT	SWB	135	0	150	0	15	0	
21162	JB Bigley #1	MT	SWB	315	0	275	0	40	0	
21163	Dee D. Dunkle #1	MT	SWB	450	5	415	3	35	2	
21164	Richey Reed #1	MT	SWB	375	0	365	0	10	0	
21165	OP Christopher #26C	MT	TPL	475	0	425	0	50	0	
21166	Owen Reed #1	MT	TPL	335	0	300	0	30	0	
21167	C. Williams #1	MT	TPL	285	0	300	0	-15	0	
21168	Presdee #1	MT	TPL	260	15	250	20	10	-5	
21169	M. Pickenpaugh #4	MT	TPL	485	0	475	0	10	0	
21170	John Jenkins #1	MT	TPL	515	0	525	0	-10	0	
21171	Ellis Miller #3	MT	SWB	375	0	400	0	-25	0	
21172	OP Brown #15B	MT	TPL	350	0	350	0	0	0	
21173	L. Stephenson #2	MT	SWB	325	0	335	0	-10	0	

Appendix 11


Vogel's Inflow Performance Relationship Curve
Bottom Hole Pressue
Fraction of Reservoir Pressure
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Producing Rate
Percentage of Maximum

Appendix 12

Study Group Analysis Summary

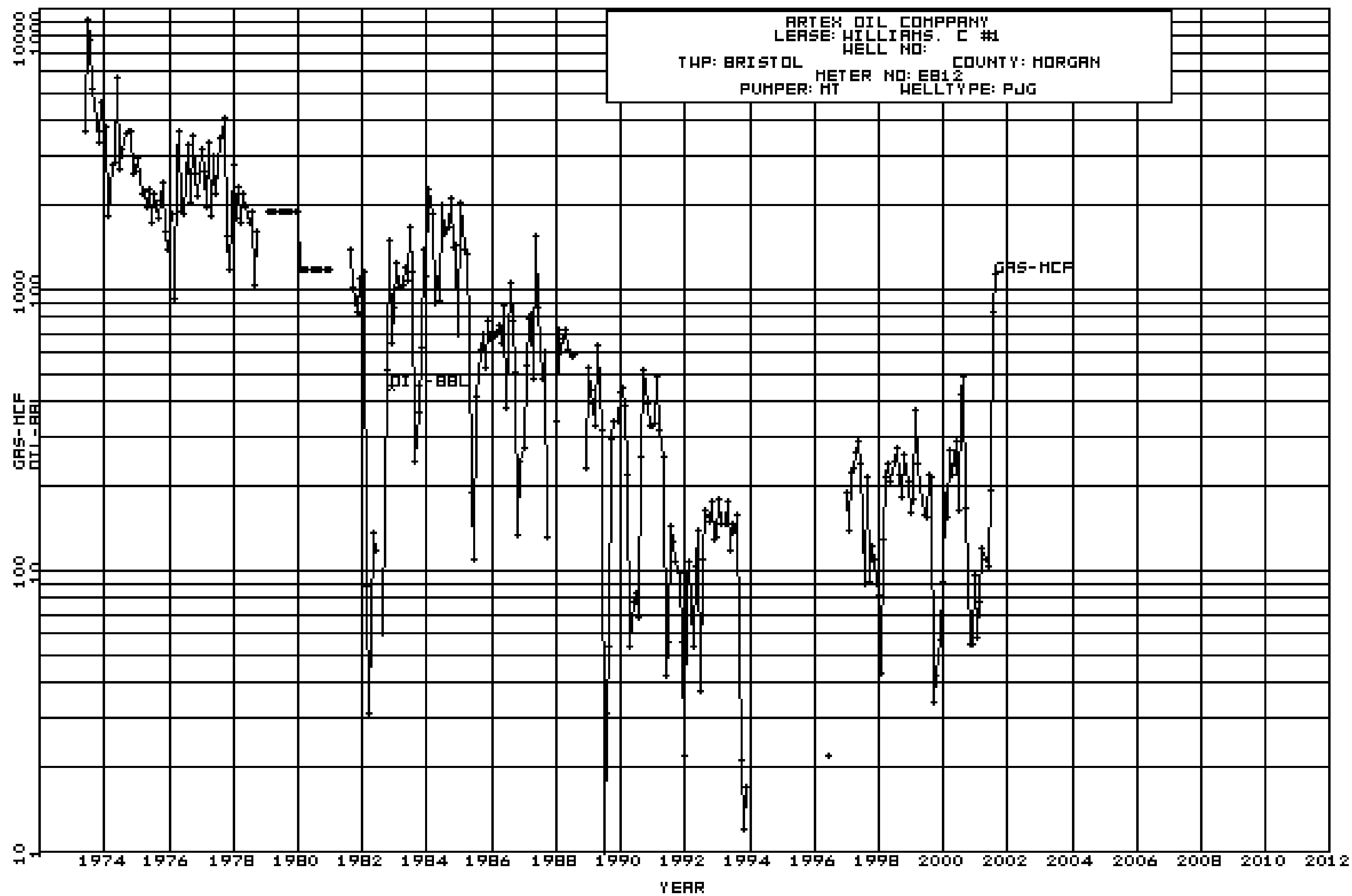
Lease Name	Well Type	Major Cause of Abnormal Decline	Remediation Strategy	Estimated Cost	Economic Summary Mcfd / M$ / Payout
1. E. Carrick #1	TPL	Mechanical Failure	Repair and Return to Production	$18,000	35 / 0.5 / 6
2. R. Florence #1	TPL	Mechanical Failure	Additional Analysis Required	$15,000	/ /
3. R. Krapps #1	TPL	Mechanical Failure	Repair and Return to Production	$6,000	13 / 0.5 / 5
4. M. Pickenpaugh #3	TPL	Mechanical Failure	Repair and Return to Production	$5,000	10 / 0.5 / 6
5. OP Combs #4B	TPL	Mechanical Failure	Repair and Return to Production	$15,000	12 / 1.3 / 14
6. Reed #1	PJG	Mechanical Failure	Repair and Return to Production	$5,000	8 / 0.6 / 7
7. R. Krapps #2	TPL	Mechanical Failure	Repair and Put on Pump	$18,000	10 / 1.8 / 20
8. J. McCall #1	TPL	Gas System Restriction	Compression Required	$1500	9 / 0.2 / 2
9. W. Fitzgerald #1	TPL	Fluid Accumulation	Run Tubing and Rods	$10,000	8 / 1.3 / 14
10. A. Larrick #1	SWB	Fluid Accumulation	Run Tubing and Put on Pump	$18,000	10 / 1.8 / 20
11. Richey Dunkle #1	SWB	Fluid Accumulation	Return to Pump	$18,000	10 / 1.8 / 20
12. Richey Lucille #1	SWB	Fluid Accumulation	Run Tubing and Put on Pump	$18,000	20 / 0.9 / 10
13. JB Bigley #1	SWB	Fluid Accumulation	Swab and Install Tubing Plunger	$ 2,000	5 / 0.4 / 5
14. Dee D. Dunkle #1	SWB	Fluid Accumulation	Return to Pump	$18,000	10 / 1.8 / 20
15. Richey Reed #1	SWB	Fluid Accumulation	Swab	$1000	3 / 0.3 / 4
16. OP Christopher #26C	TPL	Fluid Accumulation	Corrected by Cycle Adjustment	$0	/ /
17. Owen Reed #1	TPL	Fluid Accumulation	Put on Pump	$14,000	7 / 2.0 / 22
18. C. Williams #1	TPL	Fluid Accumulation	Run Rods and Pump	$10,000	10 / 1.0 / 11
19. Presdee #1	TPL	Fluid Accumulation	Run Rods and Pump	$15,000	12 / 1.3 / 14
20. M. Pickenpaugh #4	TPL	Fluid Accumulation	Run Rods and Pump	$15,000	5 / 3.0 / 33
21. John Jenkins #1	TPL	Fluid Accumulation	Swab and Return to Production	$1000	3 / 0.3 / 4
22. Ellis Miller #3	SWB	Fluid Accumulation	Run Tubing and Put on Pump	$18,000	10 / 1.8 / 20
23. OP Brown #15B	TPL	Mechanical Failure	Repair and Return to Production	$5,000	6 / 0.8 / 9
24. L. Stephenson #2	SWB	Fluid Accumulation	Return to Pump	$18,000	3 / 6.0 / 66

Appendix 13

C. Williams #1 Well Work Chronology

05/18/1973	Total Depth 4750', 4715' of 4 ½" casing
05/15/1973	Twenty perforations from 4,562'-4,672' in the Clinton Sand 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 mcfd, 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 to 4,694'.
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

Appendix 14



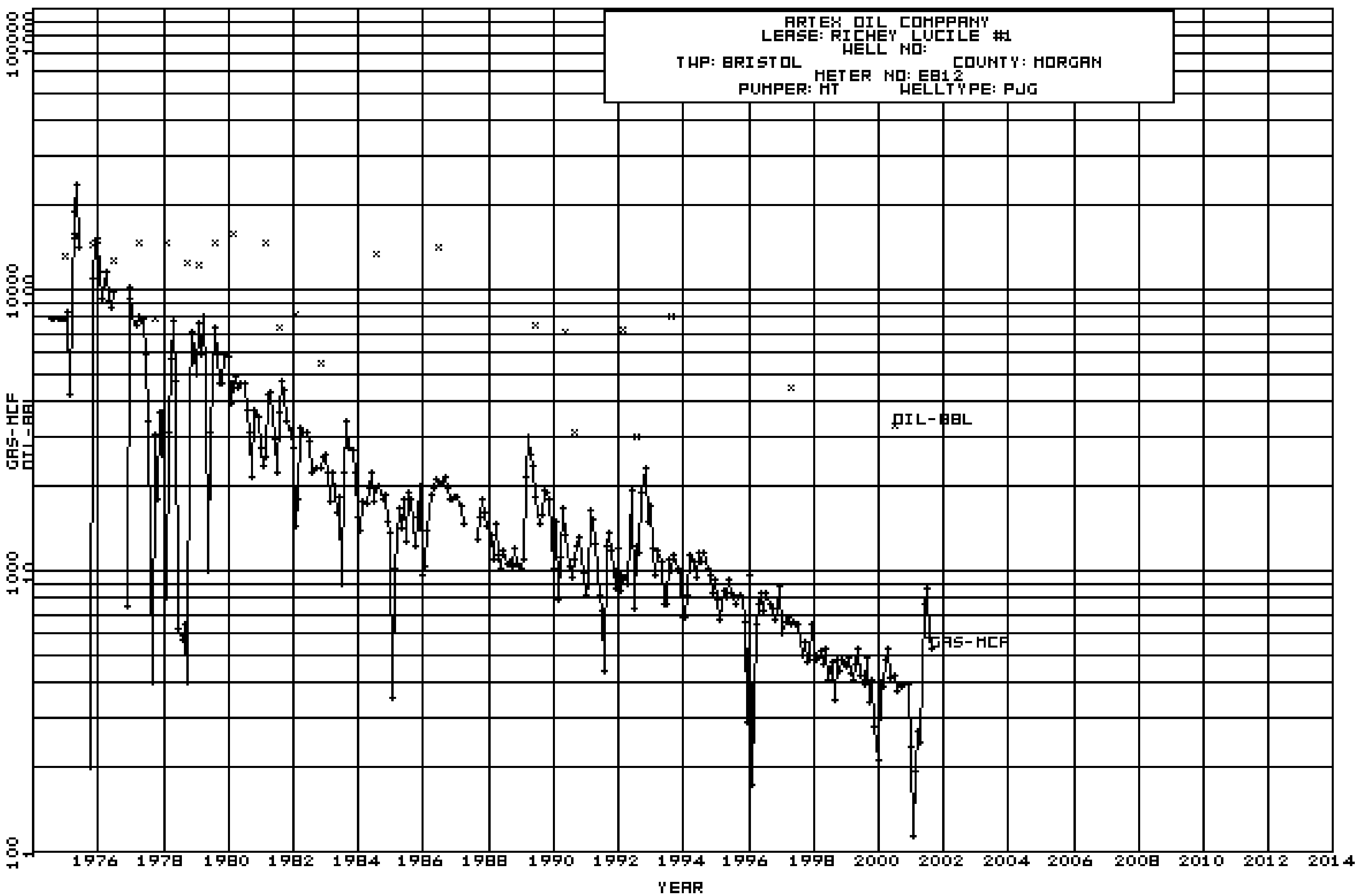
ARTEX OIL COMPPANY
LEASE: WILLIAMS. C #1
WELL NO:
TWP: BRISTOL
COUNTY: MORGAN
METER NO: E812
PUMPER: MT
WELLTYPE: PJG
GAS-MCF
OIL-BBL
GAS-MCF
OIL-BBL
10000
1000
1000
100
100
10
10
1
1974
1976
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
YEAR

Appendix 15

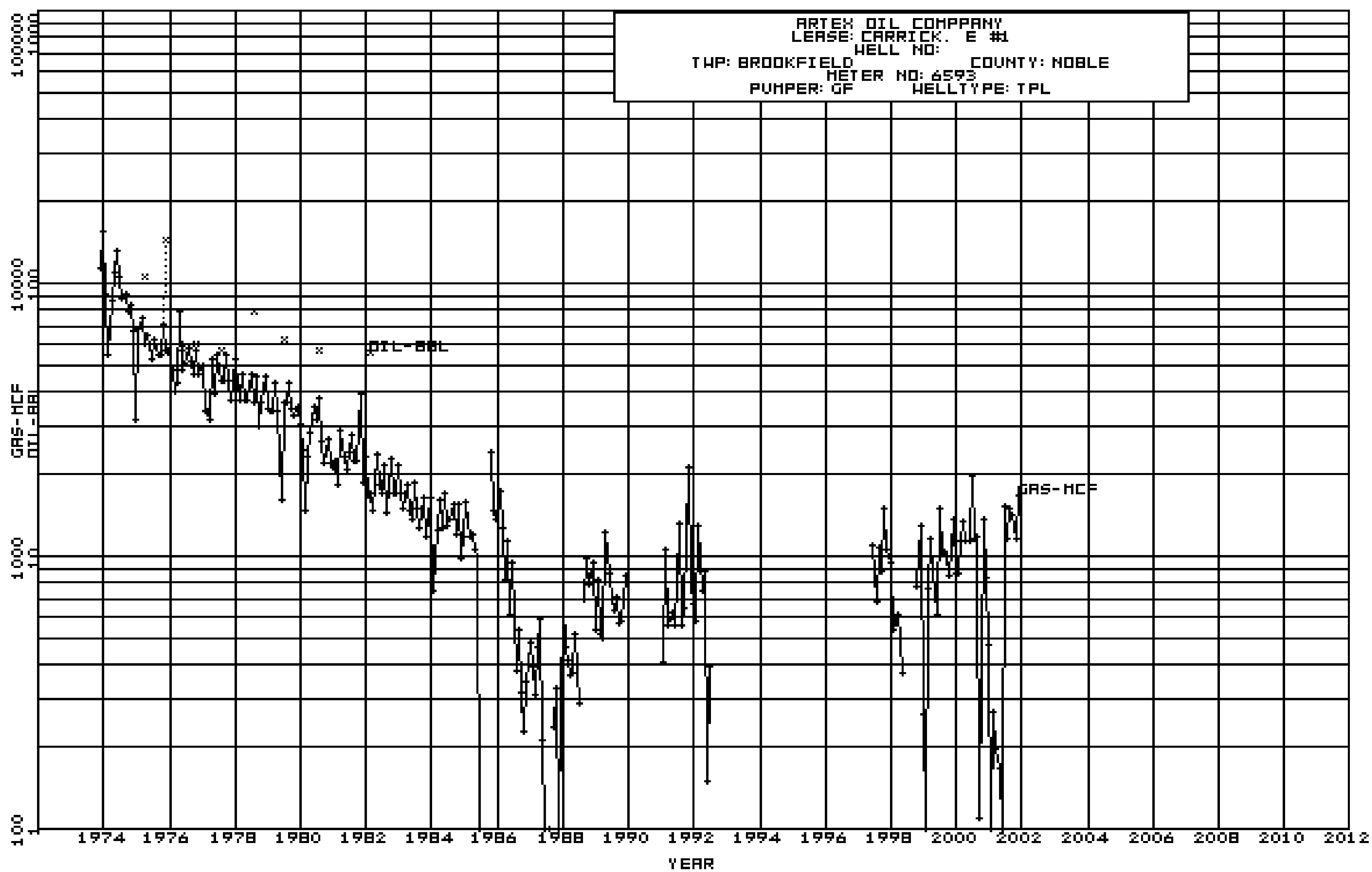
Lucille Richey #1 Well Work Chronology

06/15/1974	Total Depth 4800’, 4780’ of 4 ½” 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 mcfd, Initial shut in pressure, 1400 psi, 85-day average production 485 mcfd.
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.

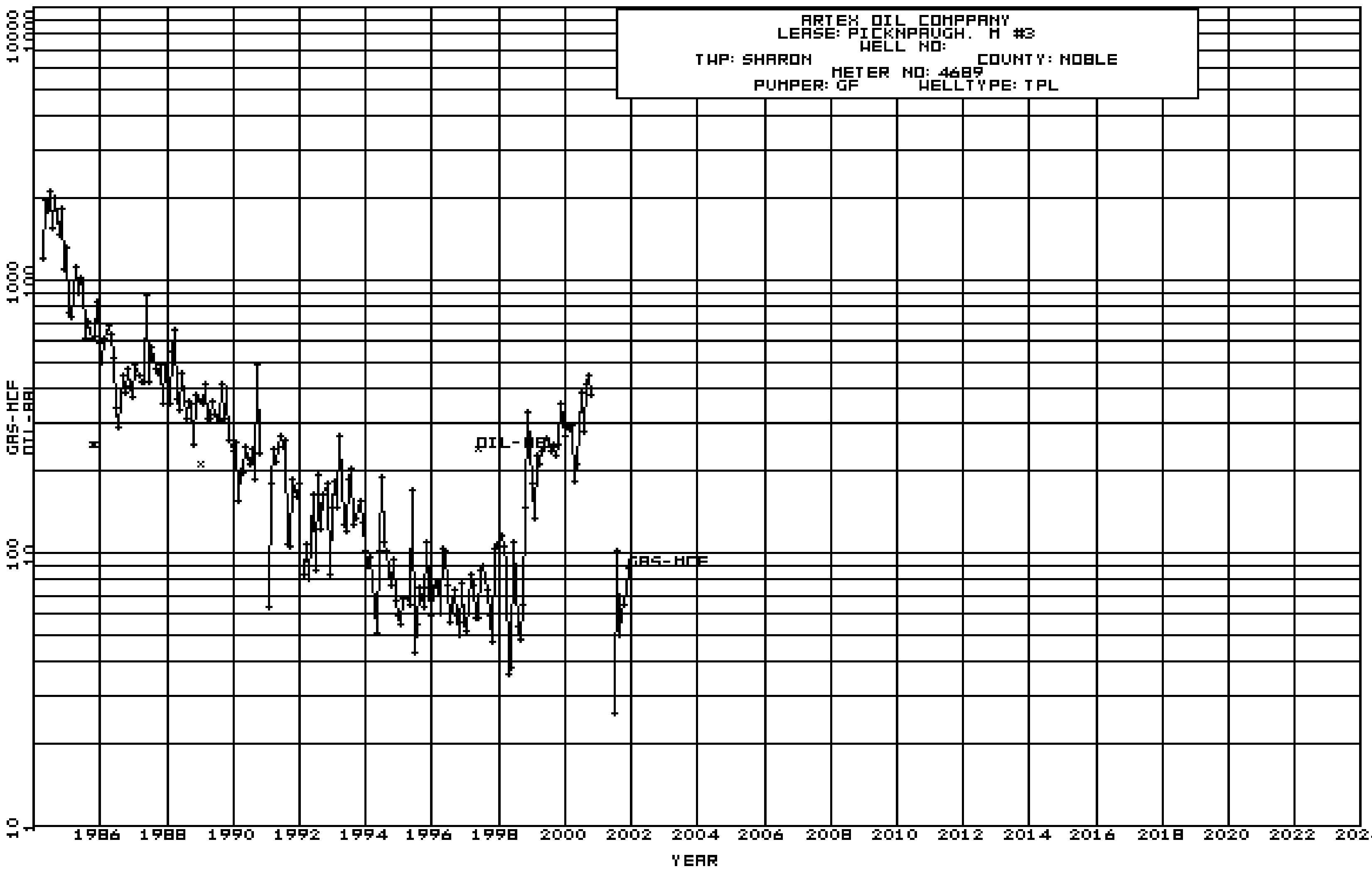
Appendix 16


ARTEX OIL COMPPANY
LEASE: RICHEY LUCILE #1
WELL NO:
TWP: BRISTOL
COUNTY: MORGAN
METER NO: E812
PUMPER: MT
WELLTYPE: PJG
OIL-BBL
GAS-MCF
100000
10000
1000
100
1000
100
10
1
YEAR
1976
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014

Appendix 17

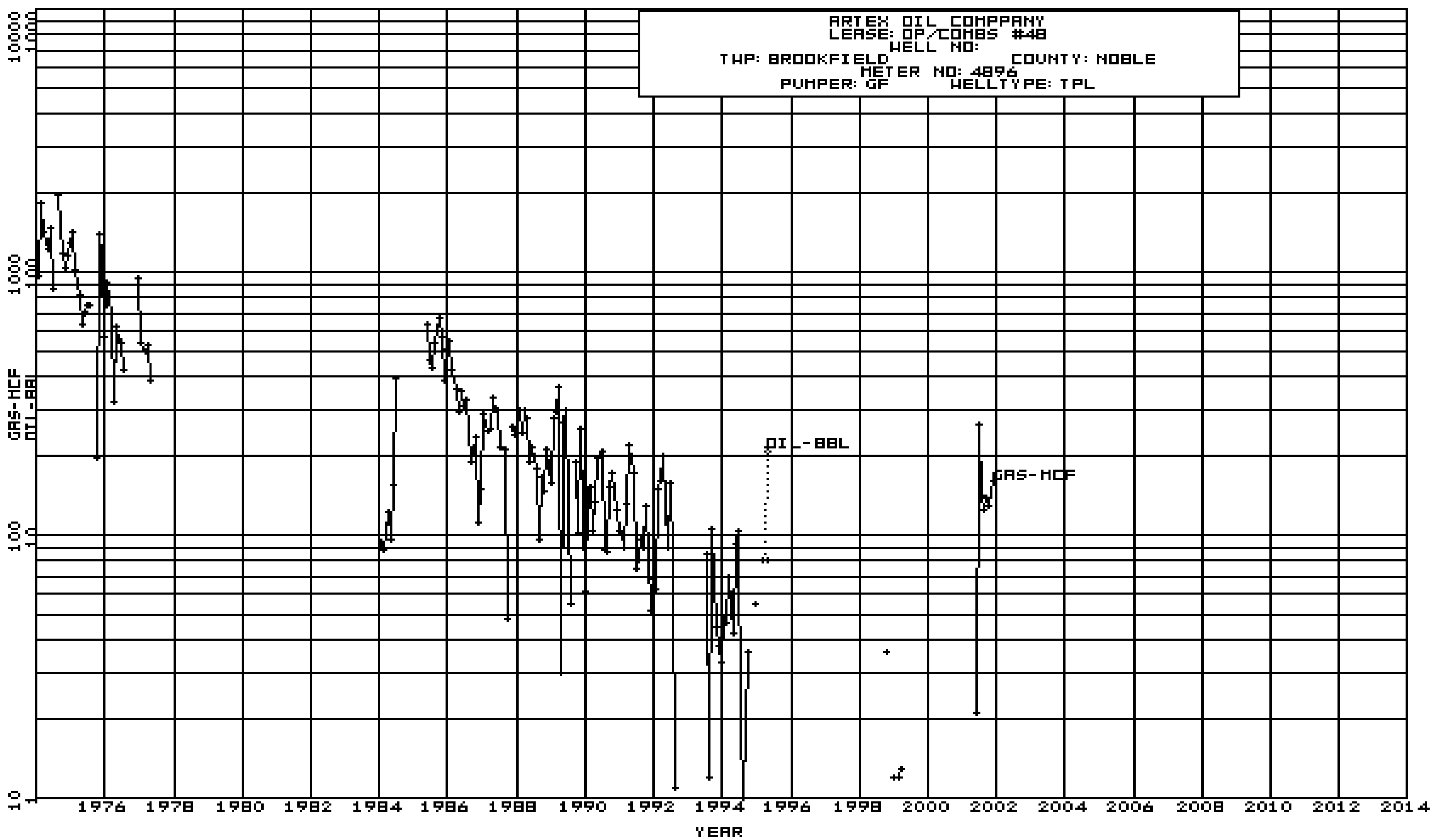

ARTEX OIL COMPPANY
LEASE: CARRICK. E #1
WELL NO:
TWP: BROOKFIELD COUNTY: NOBLE
METER NO: 6593
PUMPER: GF WELLTYPE: TPL
OIL-BBL
GAS-MCF
GAS-MCF
OIL-BBL
100000
1000
10000
100
1000
10
100
1
1974
1976
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
YEAR

Appendix 18

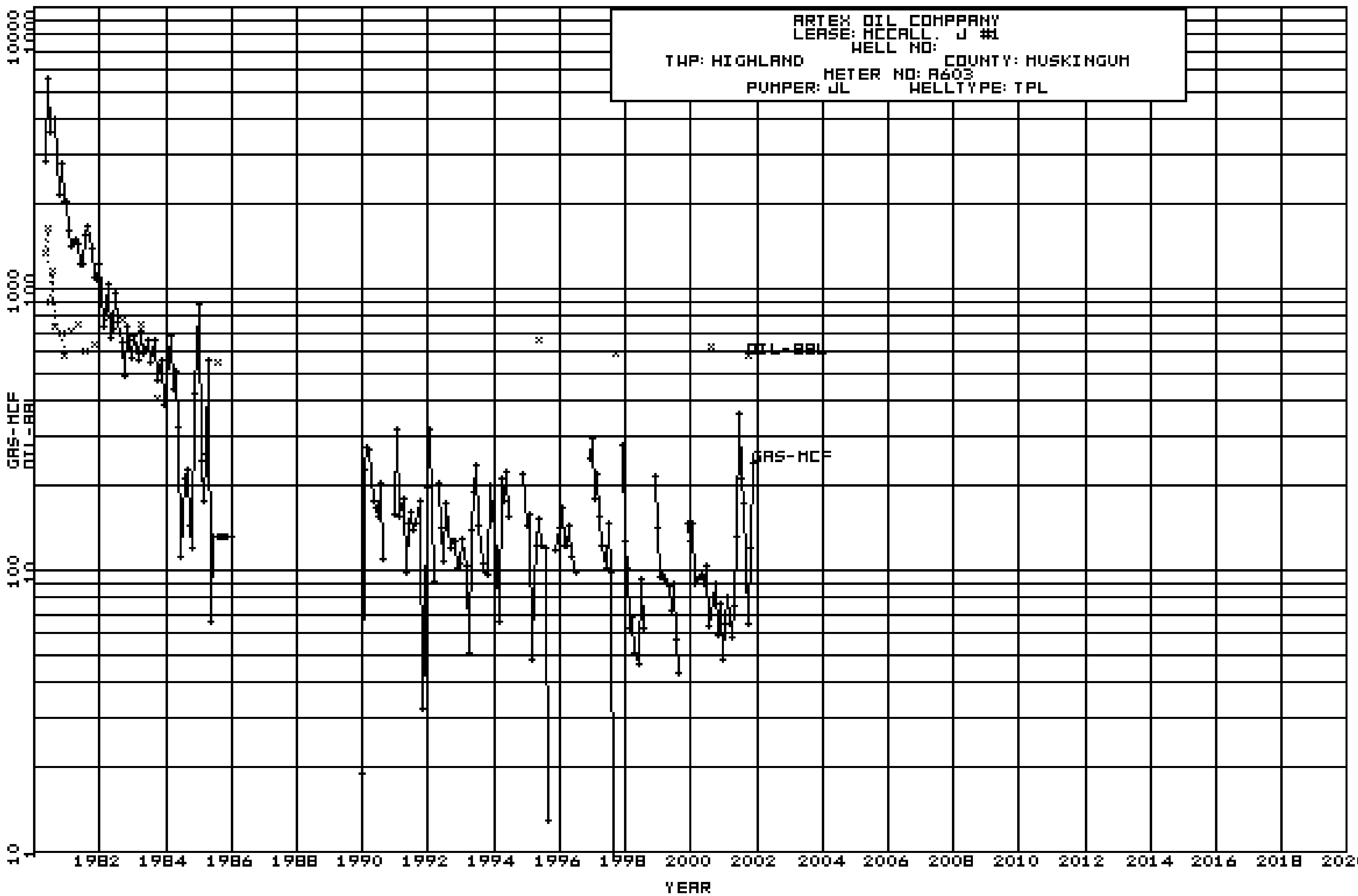


ARTEX OIL COMPPANY
LEASE: PICKNPAUGH, M #3
WELL NO:
TWP: SHARON
COUNTY: NOBLE
METER NO: 4689
PUMPER: GF
WELLTYPE: TPL
GAS-MCF
OIL-BBL
10000
1000
100
10
1000
100
10
1
OIL-BBL
GAS-MCF
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
YEAR

Appendix 19

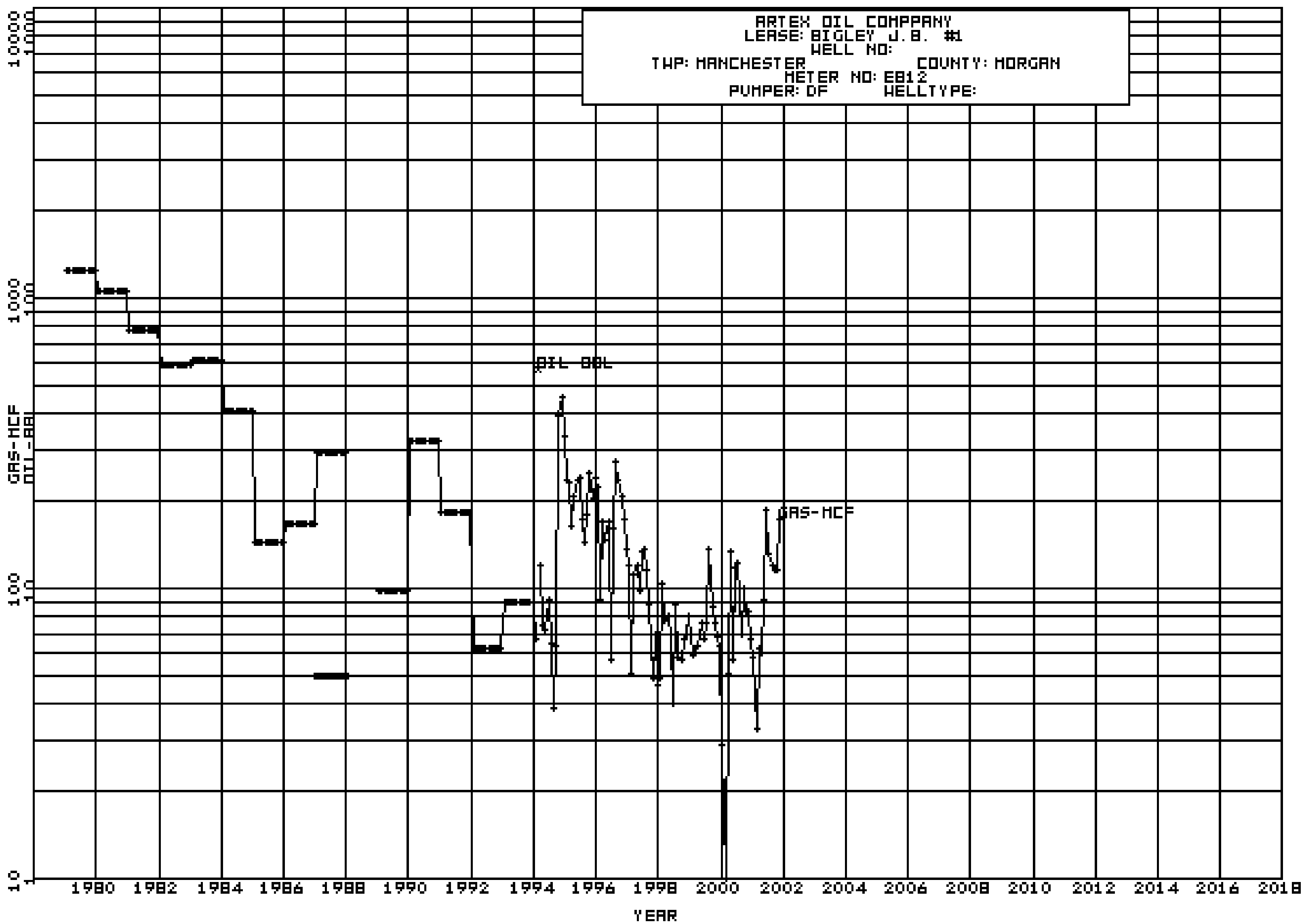

ARTEX OIL COMPPANY
LEASE: OP/COMBS #48
WELL NO:
TWP: BROOKFIELD
COUNTY: NOBLE
METER NO: 4896
PUMPER: GF
WELLTYPE: TPL
OIL-BBL
GAS-MCF
GAS-MCF
OIL-BBL
10000
1000
100
10
1
1976
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
YEAR

Appendix 20

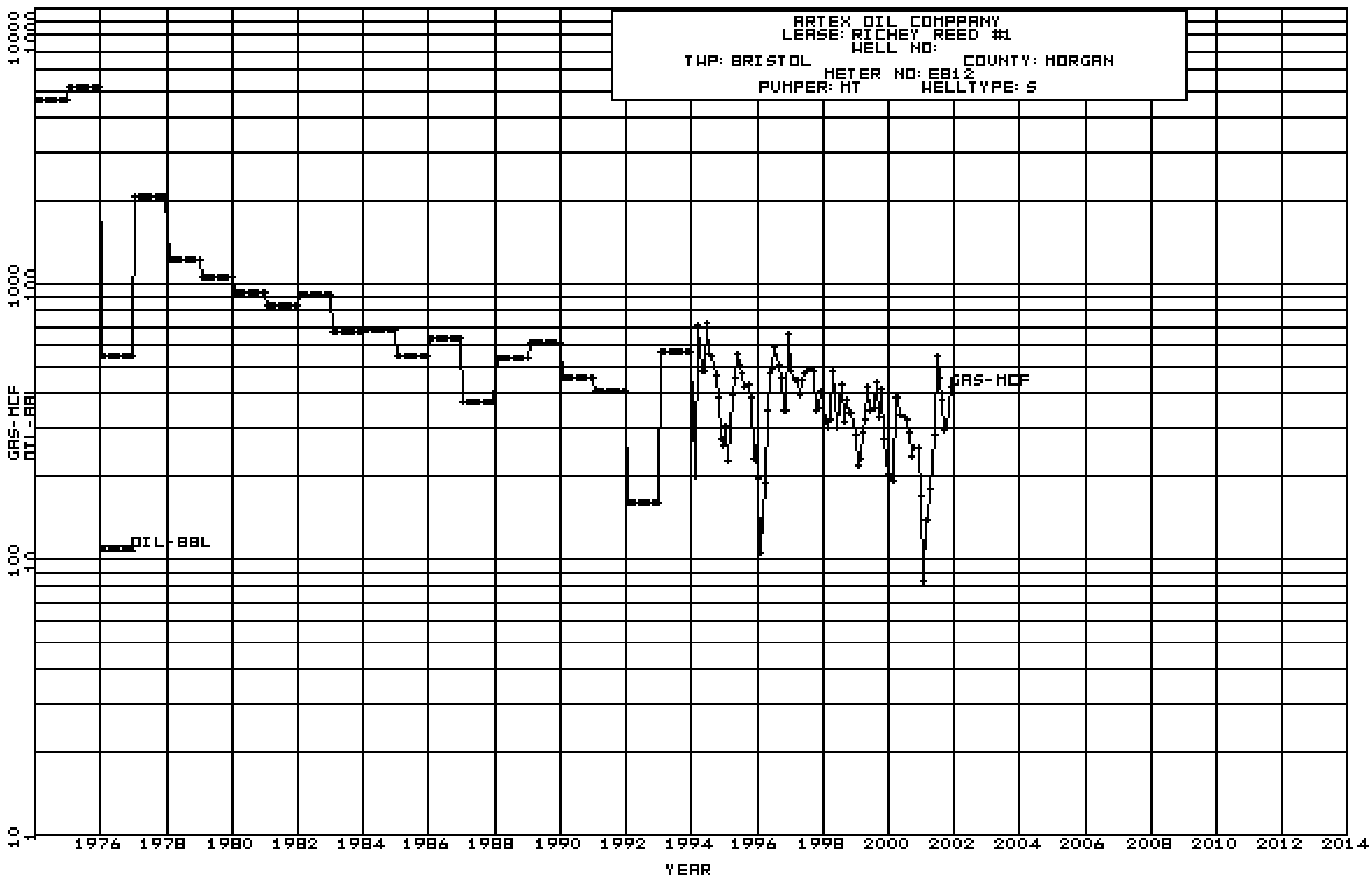


ARTEX OIL COMPPANY
LEASE: MCCALL, J #1
WELL NO:
TWP: HIGHLAND
COUNTY: MUSKINGUM
METER NO: A603
PUMPER: JL
WELLTYPE: TPL
OIL-BBL
GAS-MCF
GAS-MCF
OIL-BBL
10000
1000
100
10
1000
100
10
1
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
YEAR

Appendix 21


ARTEX OIL COMPPANY
LEASE: BIGLEY J.B. #1
WELL NO:
TWP: MANCHESTER
COUNTY: MORGAN
METER NO: E812
PUMPER: DF
WELLTYPE:
OIL BBL
GAS-MCF
GAS-MCF
OIL-BBL
10000
1000
100
10
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
YEAR

Appendix 22



ARTEX OIL COMPPANY
LEASE: RICHEY REED #1
WELL NO:
TWP: BRISTOL
COUNTY: MORGAN
METER NO: E812
PUMPER: MT
WELLTYPE: S
GAS-MCF
OIL-BBL
10000
1000
1000
100
100
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1976
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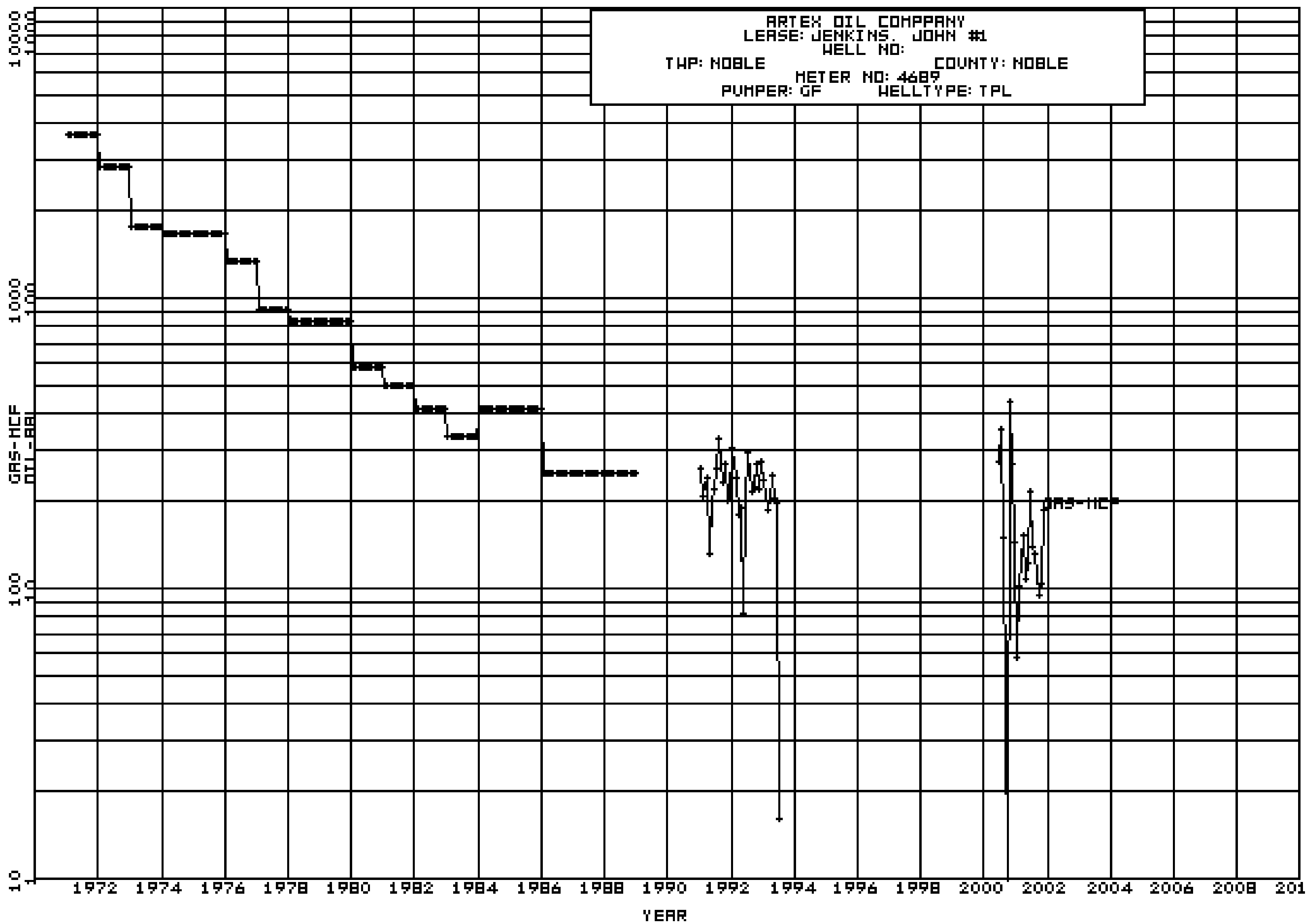
2010
2012
2014
YEAR
OIL-BBL
GAS-MCF

Appendix 23


ARTEX OIL COMPPANY
LEASE: JENKINS, JOHN #1
WELL NO:
TWP: NOBLE
COUNTY: NOBLE
METER NO: 4689
PUMPER: GF
WELLTYPE: TPL
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OIL-BBL
10000
1000
1000
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100
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1972
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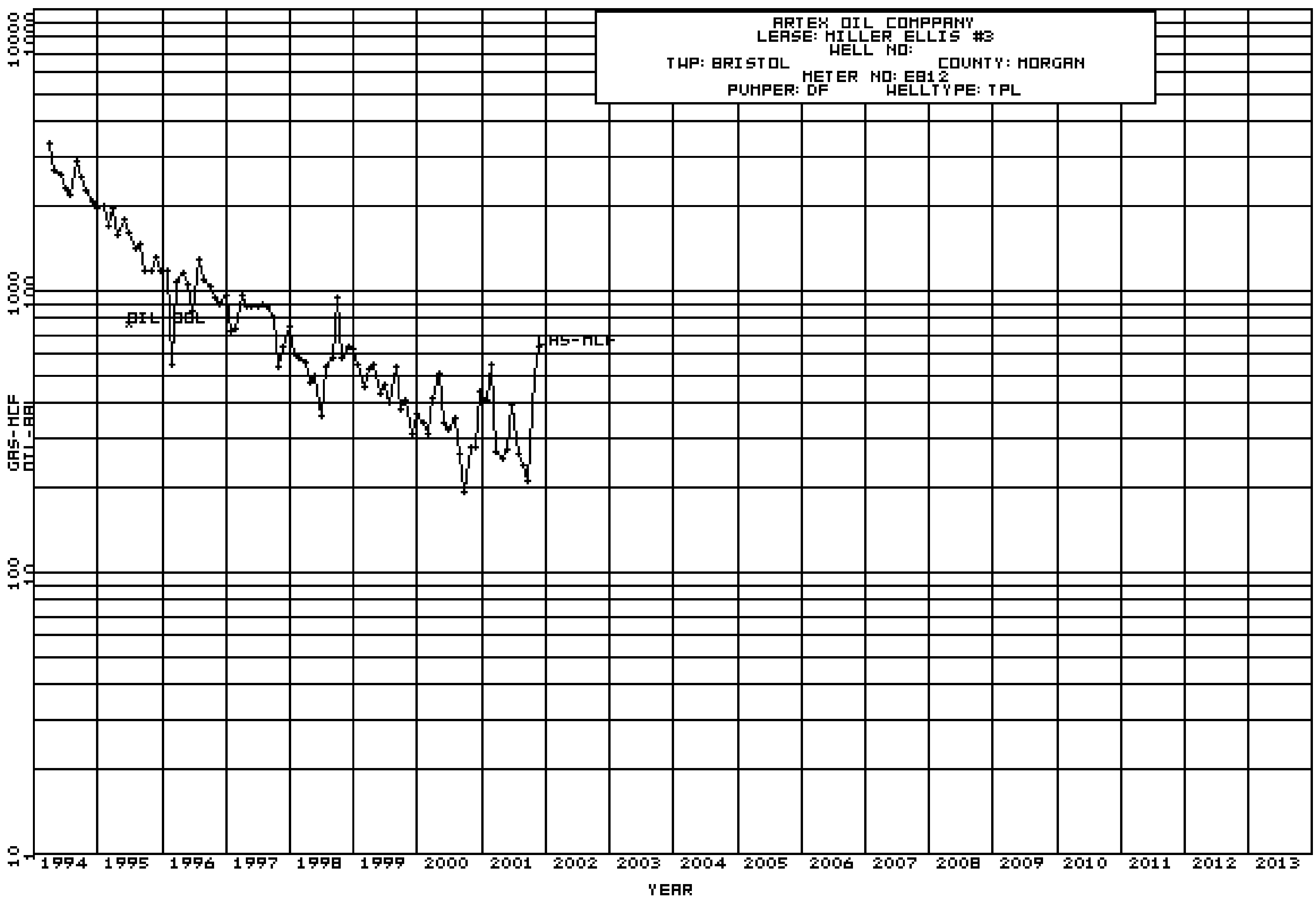
2010
YEAR
GAS-MCF

Appendix 24



ARTEX OIL COMPPANY
LEASE: MILLER ELLIS #3
WELL NO:
TWP: BRISTOL
COUNTY: MORGAN
METER NO: E812
PUMPER: DF
WELLTYPE: TPL
OIL-BBL
GAS-MCF
10000
1000
1000
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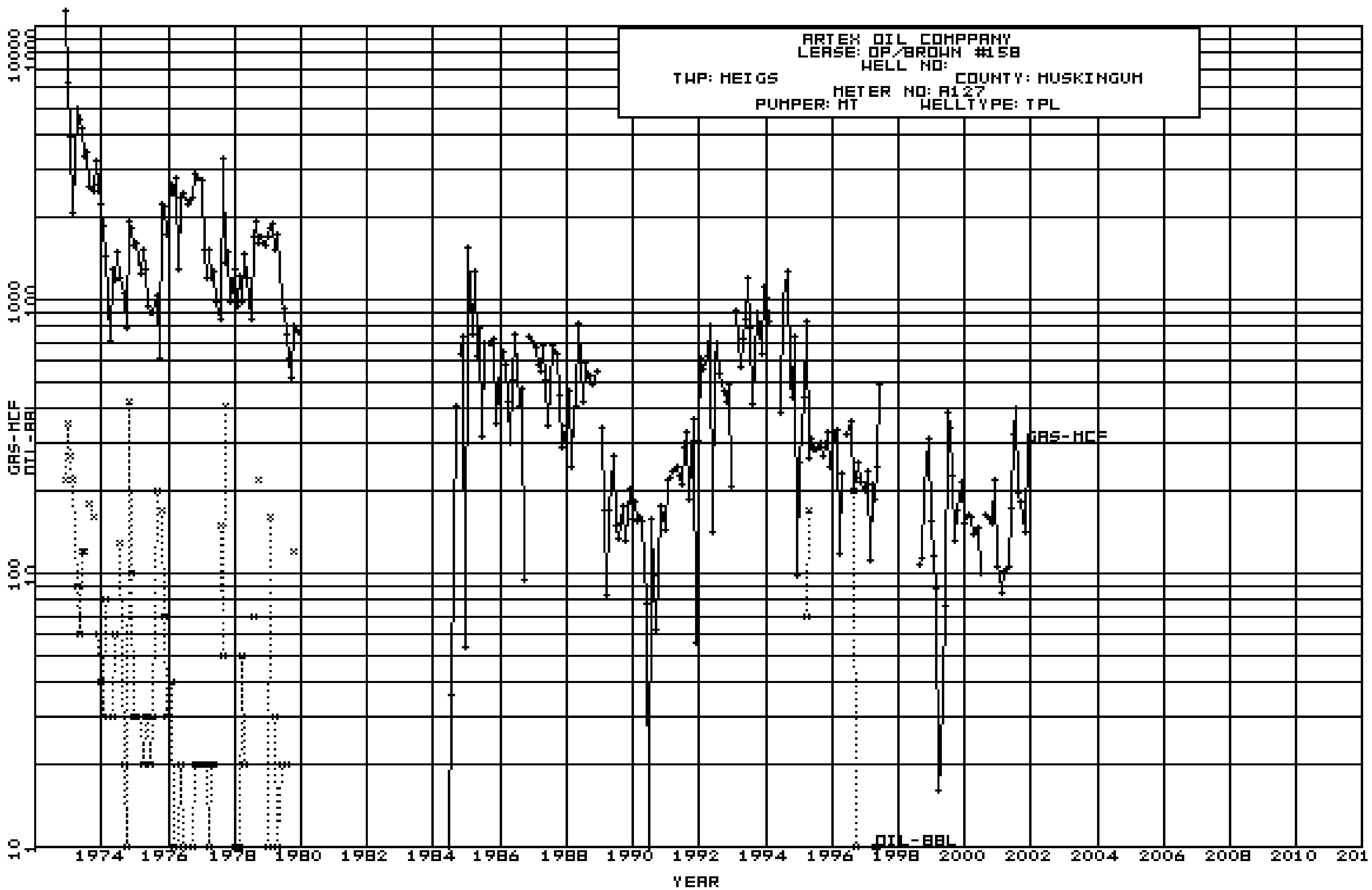
Appendix 25



ARTEX OIL COMPPANY
LEASE: OP/BROWN #158
WELL NO:
TWP: MEIGS
COUNTY: MUSKINGUM
METER NO: A127
PUMPER: MT
WELLTYPE: TPL
GAS-MCF
OIL-BBL
10000
1000
1000
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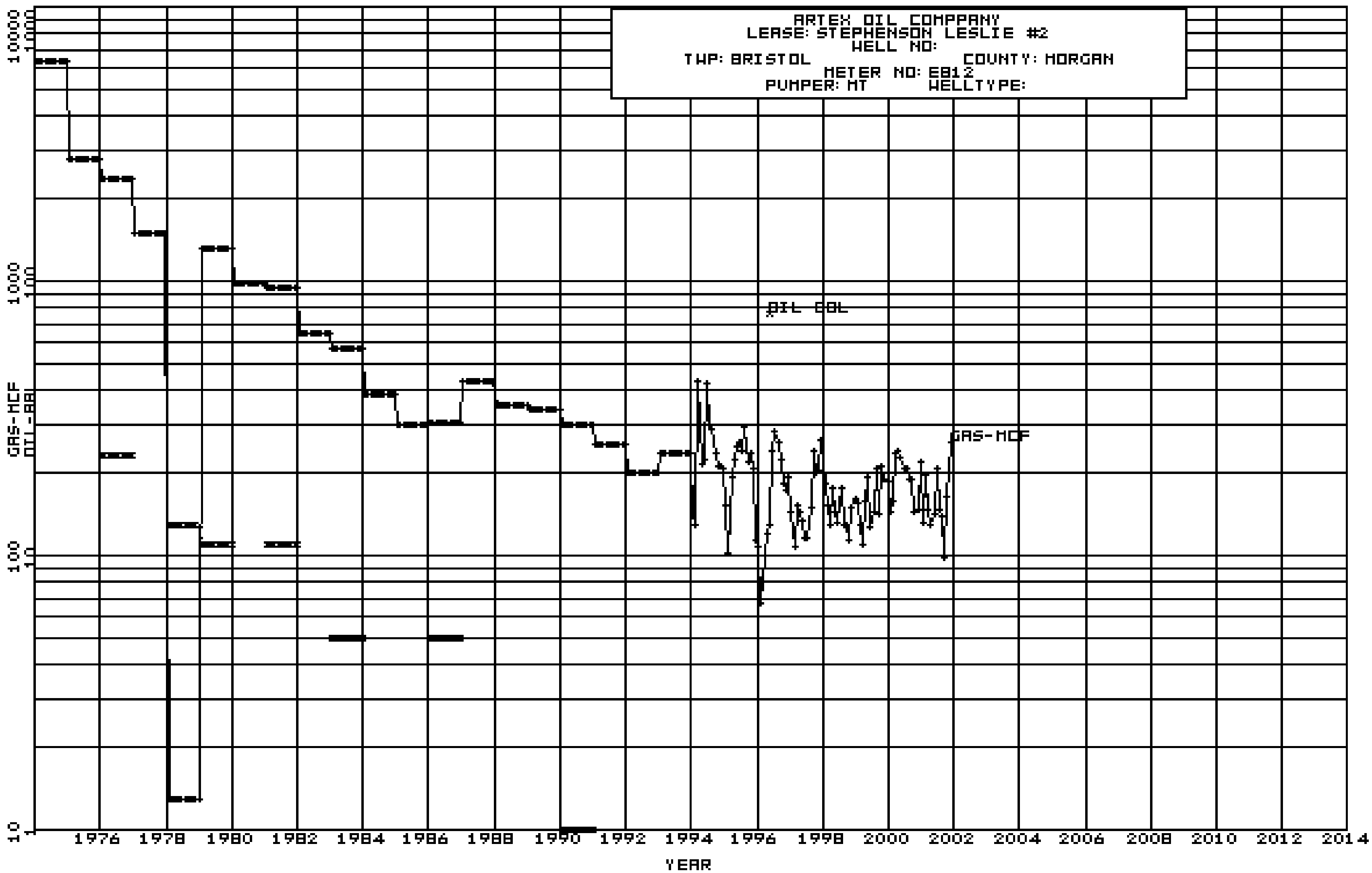
2012
YEAR

Appendix 26



ARTEX OIL COMPPANY
LEASE: STEPHENSON LESLIE #2
WELL NO:
TWP: BRISTOL
COUNTY: MORGAN
METER NO: E812
PUMPER: MT
WELLTYPE:
OIL BBL
GAS-MCF
GAS-MCF
OIL-BBL
10000
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1000
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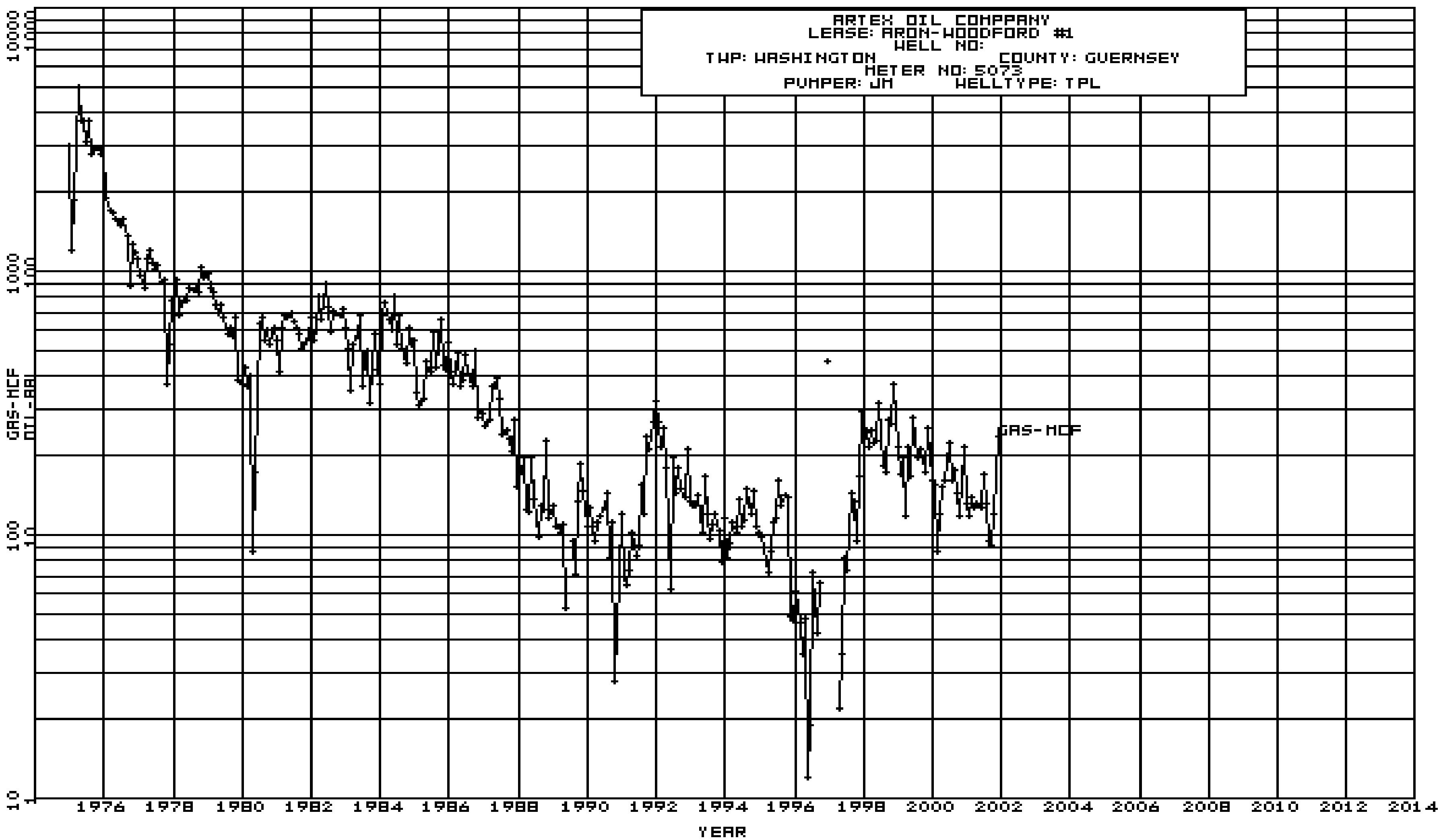
2014
YEAR

Appendix 27

Aron Woodford Unit #1 Well Work Chronology

11/02/1974	TD well @ 5,867', 4 ½" set at 5,862' w/ 125 sacks 50/50 Poz-Mix cement.
12/15/1974	12 perforations from 5,707'- 5,711', 5,720' - 5,724' and 5780'-5783' Fracture stimulated with 500 gallons 15% acid, 1,980 barrels of water, and 41,500# 20/40 sand Ran 173 joints 1 ½" tubing set at 5,729'.SN @ 5,796'. Installed 1 ½" plunger lift equipment.
11/14/1974	Initial absolute open flow 2,178 mcfd. Initial shut in pressure 1450 psi.
07/17/1987	Installed new 1 ½" KL Hollow plunger
05/19/1997	MIRU Swab Rig - plunger ran dry. Latched onto 2nd plunger @ 5600'. Swab rig unable to pull plunger free.
05/22/1997	MIRUSU TOH w/ 1 ½" tubing. Standing valve in seating nipple salted up.
05/23/1997	Cleaned out SN, TIH w/ 1 ½" tubing without mud anchor. Dump 12 bbl fw down casing. Swabbed 7 barrels fluid w/ salt. SDFWE
05/27/1997	RDMOSU – MIRU Swab Unit. SICP 195 psi. Swabbed 7 barrels. Casing Pressure increased to 275 by 3:30 pm
05/28/1997	SICP 350, SITP 120. Swab 11 barrels through 1 ½".
05/29/1997	SICP 360, SITP 180. By-passed plunger. Ran ok. CP 320, TP 280. RDMO Swab unit.
11/01/2001	MIRUSU to convert well to pumping unit operation
11/02/2001	Blow well down, Pull 1 ½" tubing, check td
11/03/2001	Sand pump well from 5729'-5862'
11/04/2001	TIH w/ 173 joints 1 ½" tubing, Seating Nipple @ 5,780'
11/05/2001	TIH w/ rods and pump, pump up well
11/06/2001	Set pumping unit, adjust weights
11/07/2001	Well on line, 15 mcfd, 2 bwpd, show of oil

Appendix 28


ARTEX OIL COMPPANY
LEASE: ARON-WOODFORD #1
WELL NO:
TWP: WASHINGTON
COUNTY: GUERNSEY
METER NO: 5073
PUMPER: JM
WELLTYPE: TPL
GAS-MCF
GAS-MCF
OIL-BBL
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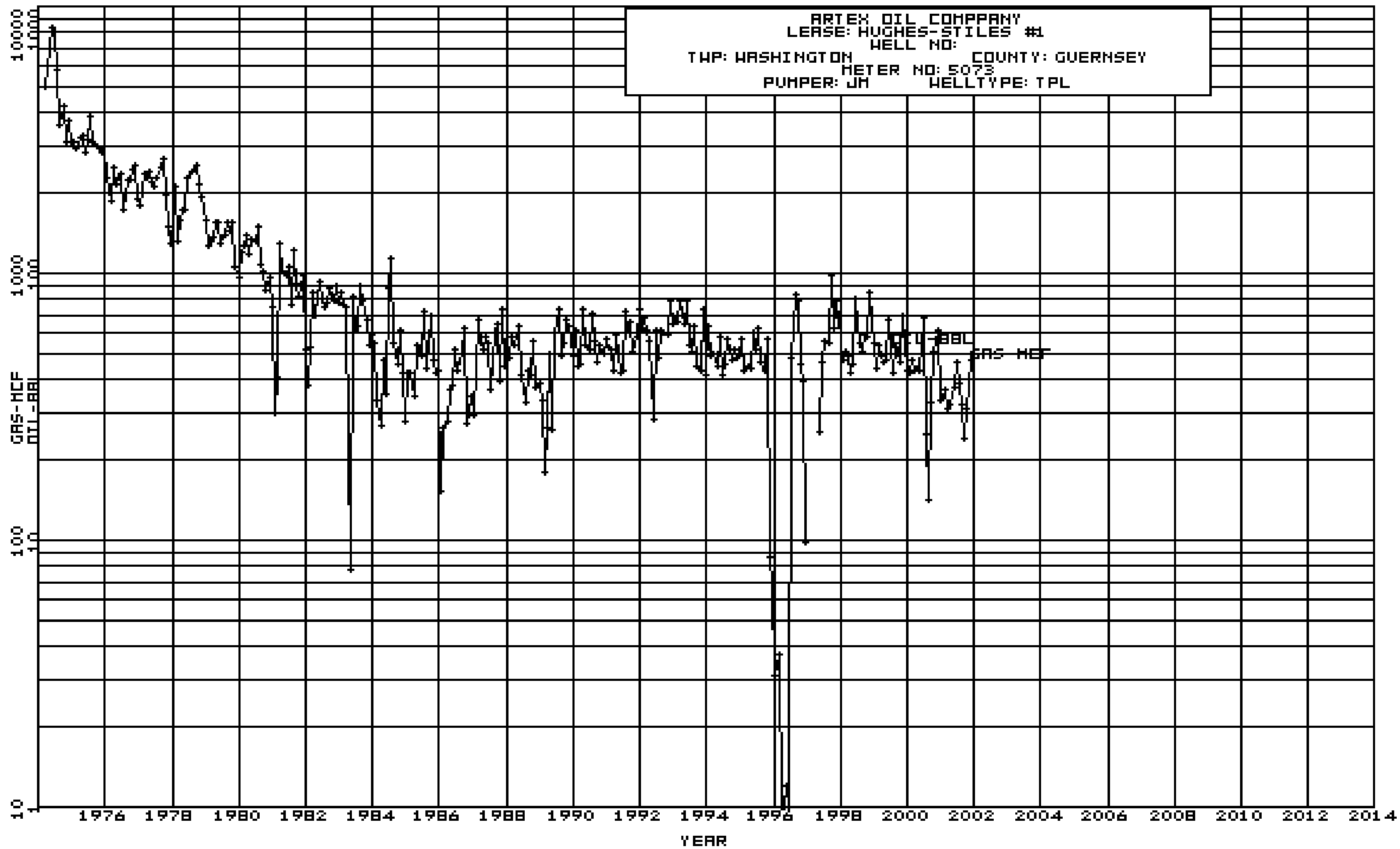
2014
YEAR

Appendix 29

Hughes Stiles #1 Well Work Chronology

12/14/1973	Total Depth 5,566’, 5,560’ of 3 ½” casing set at w/ 175 sacks 50/50 Poz-Mix cement.
12/18/1973	Fourteen perforations from 5,407’-5,488’.
12/19/2001	Fracture stimulated with 500 gallons 15% acid, 2,012 barrels water and 38,000# of 20/40 sand. Ran 160 joints 1 ½” tubing set at 5,384’. After swabbing and well kicked off and shut in for 72 hours shut in pressure 1450 psi.
01/03/1974	Initial absolute open flow 1,781 mcfd. Initial shut in pressure
08/22/2000	MIRU EDI Slickline unit, fish brush plunger @ 5,387’, pulled second hollow steel plunger loose from seating nipple. Well started gassing.
08/24/2000	Drop new bumper spring and new hollow steel plunger.
11/01/2001	MIRUSU, pull 1 ½” tubing and visually inspect.
11/02/2001	Check total depth, clean out well to td.
11/03/2001	Ran 160 joints 1 ½” tubing. Seating nipple with 15’ mud anchor set at 5,450’
11/04/2001	Run pump and 170 rods.
12/05/2001	Set pumping unit, adjust weights
11/06/2001	Well on line, 19 mcfd, 2 barrels of water per week

Appendix 30



ARTEX OIL COMPPANY
LEASE: HUGHES-STILES #1
WELL NO:
TWP: WASHINGTON
COUNTY: GUERNSEY
METER NO: 5073
PUMPER: JM
WELLTYPE: TPL
OIL-BBL
GAS-MCF
10000
1000
100
10
1000
100
10
1
GAS-MCF
OIL-BBL
1976
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