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The Use of Computers in Well Test Analysis

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ABSTRACT

The advent of small and portable microcomputers provides interesting new possibilities for the acquisition and analysis of well test data. In particular, there is a considerable saving in time if the data is transferred directly (or remotely using a modem link) to the computer for scaling, filtering and plotting. In addition, since present day microcomputers have considerable processing power, it is possible to perform all of the interpretation using the same portable microcomputer.

The advantages of doing this are several. Computerized analysis using automated techniques can provide good estimates from much shorter test data than is required for standard graphical analysis. Thus it is possible to analyze the test at the same time data is being collected, and to terminate the test when the data are sufficient for interpretation. Examples given in the paper demonstrate that the well test can sometimes be shortened by an order of magnitude in this way. The cost saving could therefore easily pay for the computer itself.

The advents of compact and powerful microcomputers, of computerized data acquisition and control, and of automated interpretation software represent major advances in the field of well test analysis.

1. INTRODUCTION

The power and portability of microcomputers makes possible many engineering applications at the wellsite. One of these applications is associated with pressure transient testing. In the past, well testing has required the running of a downhole tool that measured pressure as a function of time, invisible to the operator until the tool was recovered. The pressure record was then taken back to the office, and analyzed by hand. In more recent times, surface recording pressure gauges have enabled the test operator to monitor the test while it is in progress, and make decisions as to the continuation of the test. The analysis was still done back at the office. Now, with high powered microcomputers at the wellsite during a well test, it is possible to simultaneously control and analyze the test, using the same or a pair of computers.

Another advance in this area has come with computer-aided interpretation. The standard methods of well test analysis can now be mechanized on a small portable computer, and performed during the test. In addition, automated analysis makes it possible to interpret much shorter tests than can be analyzed by hand, and also provide reliability estimates for the answers.

Thus, the use of wellsite and portable microcomputers makes it possible for a well test operator to simultaneously perform, monitor and interpret the well test, and to truncate the test when the desired degree of reliability has been obtained. The results of such an approach can be obtained with smaller expenditure on tool time and on personnel, and can achieve more reliable results with fewer errors, fewer misinterpretations and fewer "no result" tests.

This paper describes the use of a microcomputer based automated interpretation program. The use of the computer permits much faster and more reliable well test results than have formerly been possible.

The next section of this paper describes the approach of the automated interpretation system. The remaining sections describe field applications using it.

2. AUTOMATED INTERPRETATION

Computerized analysis of well tests has been around for some time, since early work by Earlougher [1], Padmanabhan and Woo [2], Tsang et al [3], Padmanabhan [4], and McEdwards [5]. The basic principle of an automated match is the same as that of a manual analysis, in that data are matched to a "reservoir model" which is a forecast of the pressure change during the test. The reservoir model assumes a particular reservoir configuration, and its pressure response is a function of one or more unknown reservoir parameters, such as permeability, wellbore skin effect and distance to a reservoir boundary. In most traditional analysis methods, the matching of the model depends on the recognition of graphical "signatures" of the model, such as the semilog straight line characteristic of infinite-acting reservoir response, or the unit slope log-log straight line characteristic of wellbore storage.

The difference between automated and traditional methods is that the automated method performs the match between the measured data and the reservoir model response in a mathematical sense. This is usually done with a non-linear regression algorithm that adjusts the values of the unknown reservoir parameters in such a way as to minimize the sum of the squares of the differences between the measured pressures and the calculated reservoir model response pressures at the same instant in time. As a result of this procedure, the automated method has the capability of matching the entire range of the measured data, without being restricted to specific "signature" regions of the response. Thus the automated match can provide more reliable and self-consistent results.

The work of Rosa and Horne [6] opened up several new possibilities in automated well test analysis. By calculating the reservoir model parameter gradients in Laplace space, Rosa and Horne [6] showed how it is possible to automate the matching of almost any standard reservoir model - many of which do not have solutions that are easily determinable in real space yet have readily differentiable forms when expressed in Laplace space. In addition Rosa and Horne [6] demonstrated the estimation and use of confidence intervals as indicators of the reliability of the estimated parameter values. The confidence intervals are able to indicate whether the results are non-unique, whether the chosen reservoir model is consistent with the observed data, and whether there are sufficient data to adequately estimate a given parameter. As an example, since permeability only governs the reservoir response after wellbore storage effects have died away, an attempt to estimate permeability by matching data that lies only in the wellbore storage response region of the data will result in a very wide confidence interval. That is, the estimated result may be calculated as 15md, with a plus or minus confidence interval of 20md. This warns the operator that the result is not significant (normally, a confidence interval of less than 10% of the parameter value is required for statistical significance).

The work of Rosa and Horne [6] was extended by Guillot and Horne [7] to encompass cases in which flow rates during the test were not constant. This work demonstrated how the use of automated analysis can relax some of the restrictions placed on well test design by the traditional methods of analysis. Meunier, Kabir and Witmann [8] and Kucuk and Ayestaran [9] had formerly shown that the incorporation of the flow rate data gives rise to more precise interpretation in that more information is included in the analysis, and complications such as variable wellbore storage effect can be easily circumvented. Barua and Horne [10] and Horne and Kucuk [11] demonstrated how these approaches could be used in very practical applications (thermal falloff and gas well tests, respectively).

Finally, recent work in the same series by Barua, Horne, Greenstadt and Lopez [12] studied how the non-linear regression algorithms operate with the specific response functions characteristic of well test analysis. They were able to outline design criteria for the most solution efficient algorithm, and concluded that the Gauss-Marquardt [13] method was the most reliable except in instances when more than one reservoir parameter only weakly influenced the model response. In such cases it was shown that a variant of the Newton-Greenstadt method (Greenstadt [14]) was the best one to use.

Other than the speed of obtaining an answer, and the quantitative determination of confidence intervals, automated analysis has other advantages over traditional methods. Rosa and Horne [6] showed that it is possible to obtain reliable estimates of reservoir parameters with much shorter tests. This is because the automated matching procedure is able to estimate permeability and skin from the shape of the transition region that lies between the storage-influenced region and the infinite-acting region. The traditional approach using semilog analysis requires at least one and a half log cycles of data beyond the end of the storage-influenced region in order to identify the semilog straight line that is truly characteristic of the permeability and skin. Since the automated procedure is able to obtain the *same* answer without any semilog straight line at all, the test can be as much as ten times shorter than is necessary for standard analysis. This startling result is confirmed in the field example illustrated in the next section.

Automated analysis is not without its disadvantages however, and these must be handled carefully if the method is to become widely useful. The principle difficulty of the approach is that it is an iterative method, and must converge on a solution from an initial guess at the answer. Although it has been found by earlier authors that automated analysis will converge even from estimates that are one or even two orders of magnitude distant from the true values, the convergence is successful only about 90% of the time, depending on the quality of the data and the appropriateness of the reservoir model chosen by the engineer performing the analysis. Even though this sounds a reasonable success rate, it is not good enough for a program that is to be used confidently in everyday interpretation by users of varying experience and skill. There has to be a means by which the analysis software will *always* converge on the best possible answer. The most suitable way to do this would be to provide an on-screen graphical analysis of the data prior to the automated analysis, so that the interpretation engineer can provide the algorithm with a reasonably good initial estimate of the unknown reservoir parameters. This has the added advantage that it allows the engineer to have a close look at the data in displays with which he or she is familiar, and facilitates the selection of an appropriate reservoir model.

In the automated procedure, the program performs a non-linear regression match to the data, using the reservoir model selected by the user out of a menu of possible reservoir configurations. Most importantly, the automated match provides an answer that is free from subjective errors, bias or plain old human error. In addition, the program calculates approximate confidence intervals on the estimated answers, providing a quantitative impression of the validity of the values. Confidence intervals are made wider by noisy data, poor match, or inappropriate choice of reservoir model.

The algorithm used for the automated match is the Gauss-Marquardt [13] procedure, with added penalty functions as described by Bard [15]. This algorithm is similar to the one used by Rosa and Horne [6], with a revised line search procedure based on the one proposed by Bard [15]. In most cases it converges in six or seven iterations. Depending on the reservoir model, the required reservoir response function and its gradients with respect to the unknowns are calculated either directly (where they exist in real space) or in Laplace space.

3. FIELD EXAMPLE

The field example illustrated here is based on an actual test performed in an oil reservoir. It has been chosen here as an example since it shows a more extensive data set than is usually available in a geothermal well test. The actual test was performed continuously, not in two periods as is described here. In this discussion, the advantages of on-site microcomputer analysis (or remote analysis with modem transfer of the data) are emphasized by describing the test as if it had actually been given a preliminary interpretation while the test was still in progress. This was not actually done during the real test; even though the analysis shown here proves that the test was unnecessarily long as a result, the benefit of the on-site analysis was not available at the time the test was performed.

The test was a buildup after a long period of production, and is treated as if it were simply a drawdown (with the flow rate reversed). This is standard practice when the drawdown period is long (or unknown) compared to the buildup period.

Data measured for the well test are listed in Table 1.

Analysis after 15 hours:

After 15 hours of measurements, the pressure transient was as shown in Figures 1 (semilog) and 2 (log-log).

Table 1: Example Test Information

Compressibility (/psi):	.000005
Porosity (fraction):	.3
Viscosity (cp):	5.0
Formation volume factor (RB/STB):	1.1
Wellbore radius (feet):	0.2
Formation thickness (feet):	17
Initial reservoir pressure (psia):	2063
Flow rate before shut-in (STB/day):	100
Producing time (hours):	(long)

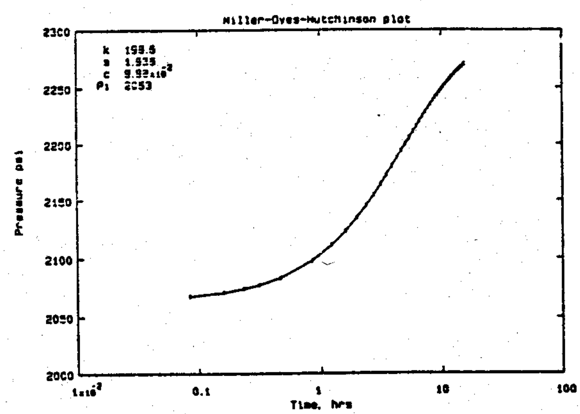

Figure 1: Semilog plot of 15-hour data (including match to data).

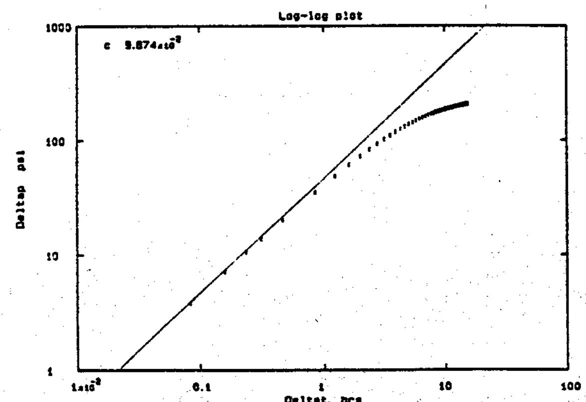

Figure 2: Log-log plot of 15-hour data.

It can be seen that the data has not yet reached infinite-acting behavior, in that no semilog straight line has appeared and the log-log plot shows that the end of the storage period (unit slope straight line) is less than one-and-a-half log cycles from the end of the test. Thus there was not yet sufficient data for traditional semilog analysis of the test. Figures 3 and 4 confirm that all of the data lay in the storage or in the transition region of the type curve and derivative type curve.

Based on traditional well test analysis criteria, it could be concluded that the test had insufficient data. Therefore the measurements were continued for a longer period, totaling 200 hours in all.

However, automated analysis has been shown to be capable of matching reliably even in transition data, and Figure 1 shows a good match to the data plotted as a full line overlaying the data (which are plotted as crosses). Table 2 lists the results inferred by the software for this match, and the confidence intervals that are to be placed on the estimates. Experience has shown us that confidence intervals of less than 10% of the estimated values represent an acceptable matched solution. Thus the estimates obtained from this first 15 hours of data are all within acceptable limits.

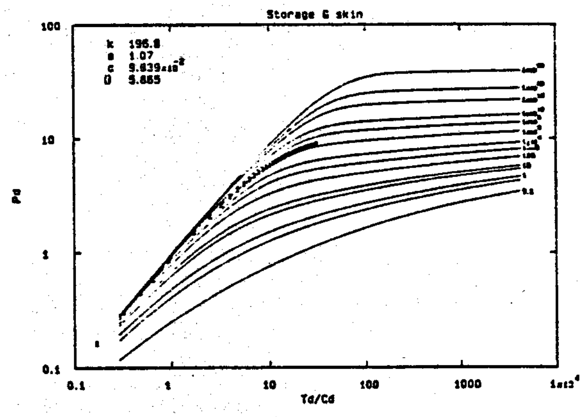

Figure 3: Type-curve match of 15-hour data.

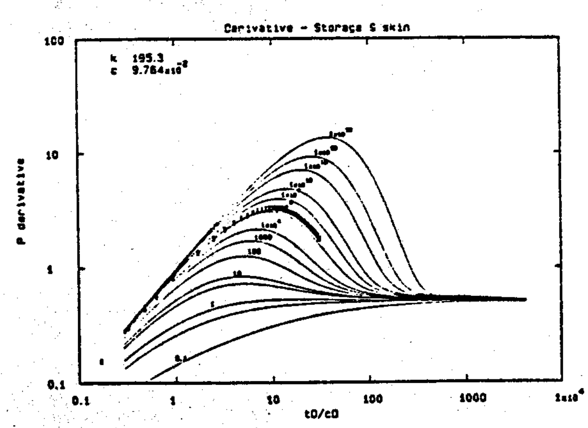

Figure 4: Derivative plot of 15-hour data.

Table 2: Estimated Results for 15 hours of Data

Variable	Estimate	±	± %
Permeability (md)	198.6	3.76	1.89%
Skin	1.94	0.168	8.67%
Storage (RB/psi)	0.100	0.00021	0.21%
Initial Pressure (psia)	2062.9	0.059	0.00%

An absolutely definitive test of the validity of the solution can be obtained by comparing the result with the answers derived from the subsequent interpretation of the full 200 hours of data.

Analysis after 200 hours:

The remainder of the test data are illustrated in Figure 5.

A good semilog straight line appears after about 60 hours. The steps of the interpretation using the automated well test analysis software are as follows:

1. Using a graphical plot of the data, a straight line is aligned through the apparent semilog straight line region of the data, as in Figure 5. The slope and position of this line allows the calculation of estimates for the permeability and the skin factor for the test.
2. Another straight line is aligned with the unit slope straight line on the log-log plot, as in Figure 2. The position of this line allows the calculation of an estimate for the wellbore storage coefficient.
3. Alternatively (or in addition), the data can be plotted over the appropriate type curve, such as the Gringarten et al [16] type curve shown in Figure 6 or the derivative type curve (Bourdet et al [17]) as in Figure 7. Moving the data with respect to the type curve allows for another calculation of the estimates for the reservoir parameters based on the pressure and time match points.
4. The computer program is then used to perform the automated match, using the estimated parameter values as starting guesses. The automated procedure calculates the best possible match to the chosen reservoir model (in a least squares sense) and estimates the approximate confidence intervals to be associated with the answers. The final match can be compared to the original data as in Figures 8, 9 and also in Figure 1.

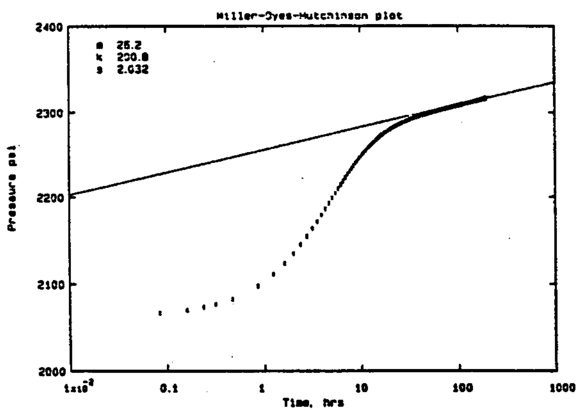

Figure 5: Semilog plot of 200-hour data (with correct straight line shown).

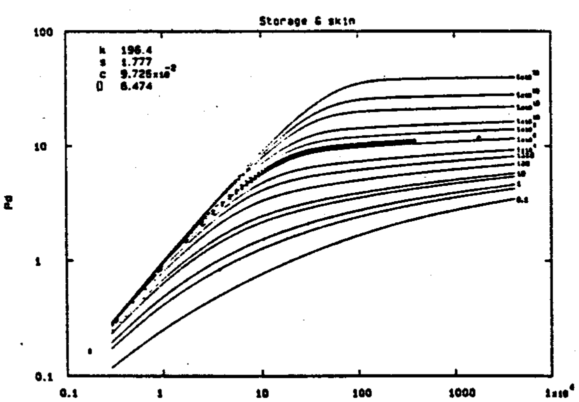

Figure 6: Type-curve match of 200-hour data.

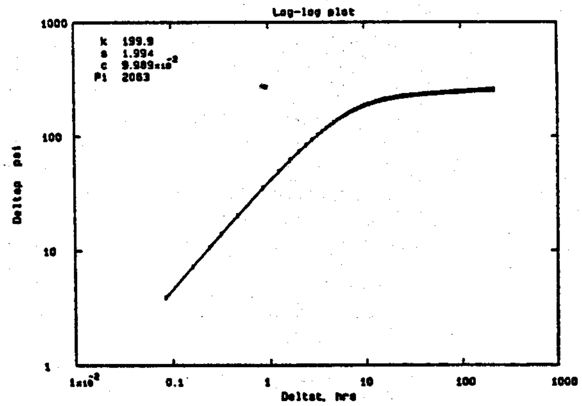

Figure 7: Derivative plot of 200-hour data.

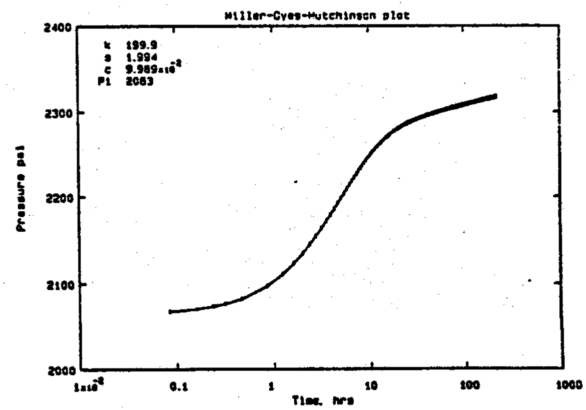

Figure 8: Best fit match to 200-hour data (semilog plot).

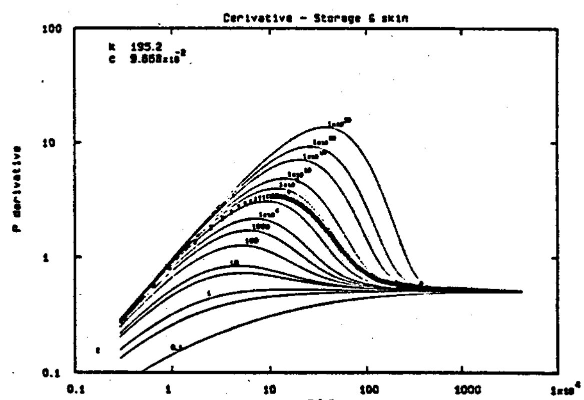

Figure 9: Best fit match to 200-hour data (log-log plot).

The results of the match to the full 200 hours of data are summarized in Table 3.

Table 3: Estimated Results for 200 hours of Data

Variable	Estimate	±	± %
Permeability (md)	199.9	0.140	0.07%
Skin	1.99	0.007	0.34%
Storage (RB/psi)	0.100	0.00005	0.05%
Initial Pressure (psia)	2062.9	0.033	0.00%

Comparison of the two solutions:

Comparison of Table 2 with Table 3 reveals that the automated procedure obtains the same answer using only the first 15 hours of the data, even though this data cannot be interpreted using traditional graphical methods. The shorter test time results in wider confidence intervals, but these are still within acceptable limits. This demonstrates that the computerized analysis procedure has been able to accurately interpret the test, using less than one tenth of the data collected. Figure 10 shows the position of the semilog straight line relative to the 15 hour test data; clearly it would be impossible to have inferred the position and slope of this line using traditional methods.

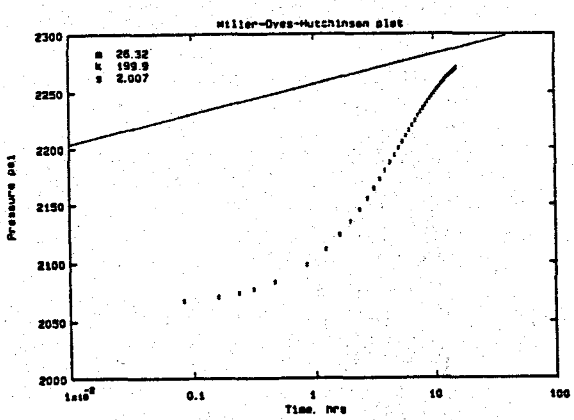

Figure 10: Semilog plot showing position of correct straight line in relation to 15-hour data.

4. APPLICATION TO MEXICAN GEOTHERMAL WELLS

During this study, several field examples from Mexican geothermal fields were analyzed by this technique.

Figure 11 shows an example of a test at Cerro Prieto M-113 that is missing the early time data, and only barely reaches the infinite acting region of the response (semi-log straight line region).

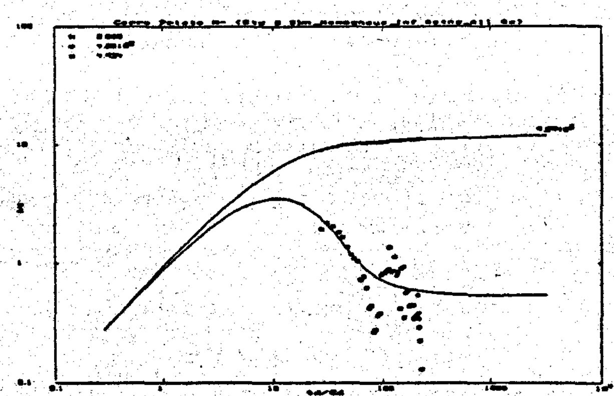

Figure 11: Well test data from Cerro Prieto M-113.

This data lies more or less entirely within the "transition" region between wellbore storage and infinite acting response regions, and is therefore particularly difficult to interpret by normal graphical methods. Table 4 shows the estimates of reservoir parameters obtained by automated analysis - even though acceptable estimates for the storage coefficient and skin factor cannot be obtained (since the early time data is all missing), it still possible to obtain the reservoir permeability within the criterion of acceptable confidence intervals. This is an example of the recovery of an interpretation from a set of welltest data that would be unlikely to be correctly analyzed by normal graphical "hand" methods.

Table 4: Estimated Results for Cerro Prieto M-113

Variable	Estimate	±	± %
Permeability (md)	2.82	0.24	8.63%
Skin	5.90	2.88	48.84%
Storage (RB/psi)	0.036	0.016	45.04%
Initial Pressure (psia)	2674.4	176.56	6.60%

In a second example, Figures 12 and 13 show two different interpretations for the same set of welltest data from well Los Azufres Az-17. (Details concerning the test are described in the Appendix). Figure 12 indicates a good match to the finite conductivity fracture type curve, and Figure 13 shows another good match (on a semilog plot) to a *normal infinite acting reservoir response* with the late time interception of a boundary effect at a an inferred boundary distance of 100 feet.

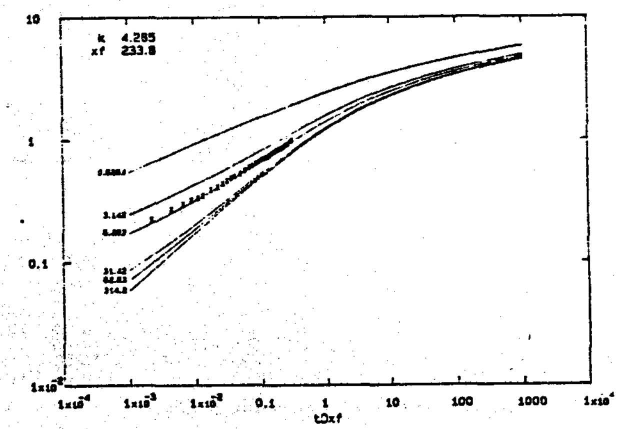

Figure 12: Well test data from Los Azufres Az-17.

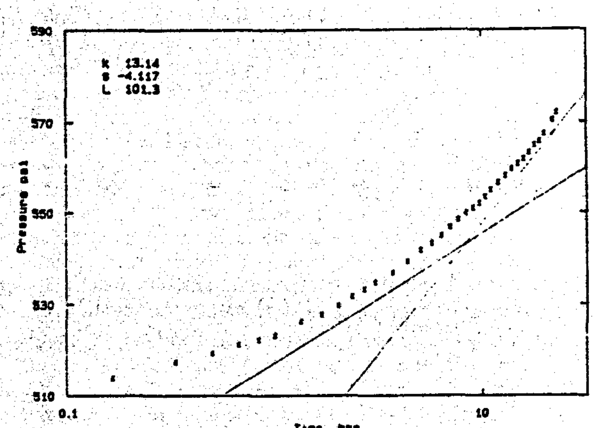

Figure 13: Well test data from Los Azufres Az-17.

Table 5: Estimated Results for Los Azufres Az-17 (model 1)

Variable	Estimate	±	± %
Permeability (md)	7.306	0.811	11.1%
Fracture length (ft)	108.70	14.30	13.16%
Fracture conductivity	18.11	4.64	25.61%

Table 6: Estimated Results for Los Azufres Az-17 (model 2)

Variable	Estimate	±	± %
Permeability (md)	12.99	2.48	19.11%
Skin	-4.10	0.12	2.90%
Storage (RB/psi)	0.00013	0.000005	3.79%
Boundary distance (ft)	101.25	0.47	0.46%

Examination of the confidence intervals for the two cases (Table 5 and 6) reveals that the apparent "boundary" interpretation is entirely unreasonable. This is because the apparent "infinite acting" semilog straight line is in fact part of the early time data, and it is the *second* straight line that is correctly representative of the reservoir permeability. In the absence of a unit slope straight line to recognize the end of the early time data region, this would have been difficult to realize in a normal manual analysis.

This second example underlines one of the principle advantages of the automated technique. Confronted with two very reasonable looking graphical matches, there is no independent way to distinguish one interpretation from the other by eye. Examination of the confidence intervals immediately shows that there is a definite difference between them. It should be noted that the estimates of the permeability in the two cases differ by almost an order of magnitude.

It is worth noting here that the resolution of the ambiguity as to which model to choose really lies in consideration of the geological structure of the reservoir. For formations such as those found at Los Azufres, a fracture intersecting the well is a much more probable explanation than an impermeable boundary 100 feet away. So in this case, a decision based on the consideration of the confidence intervals gives the same conclusion as consideration of the local reservoir geology.

5. CONCLUSIONS

The use of microcomputers in well test analysis has resulted in considerable improvements both in the acquisition and in the interpretation of data. These improvements can result in much less expensive tests, since the computer can perform data collection and test control much faster and with fewer people than manual recording. Measurements of multiple wells can be made as easily as measurements at a single well. In addition, the test can be analyzed by microcomputer, either at the site or at the home office if the data are telemetered from the measurements computer. Advances in interpretation made possible by the computerized automated analysis mean that the test need not be as long as is necessary for manual analysis.

Microcomputers can also greatly improve the analysis of tests that have already been performed under existing practise. The new capabilities of automated analysis make it possible to obtain a result from a test that was previously too short for analysis. The automated interpretation of such a test saves the execution of a new replacement test.

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Appendix - Los Azufres Az-17 Test

Well Az-17 is located in the south zone of the Los Azufres Geothermal Field, Michoacan, Mexico, and was completed in February 1980 at a depth of 627 m . The circulation losses during the drilling process were registered between 613 and 627 m depth, at which depth it is presumed that the well intersected the Puentecillas Fault. Another important geological structure nearby the well is the Agua Ceniza Fault, located at the surface at a distance 140 m east. These geological structures have slopes with respect to surface of 82 and 84 degrees (Venegas et al.[18]), respectively. The well was completed with a casing pipe of 0.2245 m in diameter from 0 to 560 m depth, and with a liner of 0.1778 m in diameter from 450 to 622 m depth. The slotted part of the liner goes from 561 to 622 m depth.In December 1980 the well produced a maximum steam flow rate kg/s. At that time, the produced steam had a little humidity, however it was gradually coming into the superheated region. Up to date, the mean specific enthalpy of the produced fluid is around 2800 kJ/kg at any well-head pressure. Based on the characteristics of this well, it was connected to a 5 MW turbogenerator unit in the second semester of 1982. Some scaling problems were detected in the turbine during the initial period of generation, however those were corrected.

February 22, 1987 well Az-17 was taken out of the generation system in order to give maintenance to the turbogenerator Unit Number 2 which was supported by this well almost without interruption since the second semester of 1982. In March of the same year, two tests were realized on this well: a production test to obtain the production output curve; and a pressure buildup test to determine the formation parameters. A little before the buildup test had started, simultaneous pressure and temperature Kuster logs were run to know the thermodynamic states of the fluid throughout the well. This information was also used to test the superheated steam well simulator developed by Upton in 1985. The pressure buildup test was carried out after that producing at a constant steam flow rate of 9.81 kg/s during 144 h. This condition was achieved by using an orifice plate of 0.0508 m. The recuperation period used was 23 h and the pressure Kuster element was located at 610 m depth.