CENTER FOR PETROLEUM AND GEOSYSTEMS ENGINEERING

CONSOLIDATED RESEARCH PROGRAM UNITED STATES GULF COAST GEOPRESSURED-GEOTHERMAL PROGRAM

LOGGING RESEARCH FINAL REPORT

1979-1992

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DISCLAIMER

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FINAL REPORT

DOE GEOPRESSURED-GEOTHERMAL ENERGY PROJECT LOGGING RESEARCH

COOPERATIVE AGREEMENT DE-FC07-85NV10412

1979-1992

Abstract:

The logging research program in the DOE Geopressured-Geothermal Energy Project was set up to (a) carry out research on logging problems important to the DOE program; (b) provide advice on logging programs in DOE wells; (c) monitor log quality during data acquisition; (d) provide log analyses as requested by DOE and (e) provide other services as skills and time permit. Funding for the project amounted to about $50,000/year from 1979 to 1985 (direct cost plus overhead). In 1986 DOE funding began to increase and was about $100,000 per year for the last three years of the project (1988-91). In addition to DOE funding, the Gas Research Institute Tight Gas Sands Project contributed to our boron research by about $7,000 per year during 1989-91, plus about $100,000 worth of core and log data from five tight gas sand wells in East and West Texas and in Wyoming.

Our specific research tasks and the results we obtained were as follows:

1. Improving the accuracy of formation water salinity prediction from the self potential log. This is important since methane solubility decreases as water salinity increases. The calculation requires knowledge of R_{mf}, the mud filtrate resistivity, which was usually known only from a measurement made at the time the well was logged. Our research showed that R_{mf} can vary considerably from day-to-day. Daily measurements of R_{mf} are needed for good estimates of formation water salinity.

2. Assessment of radioactive bullet logging as related to subsurface compaction measurements. We studied this problem because of environmental concerns about possible surface subsidence resulting from large volume brine production. An extensive literature survey established accuracy of radioactive bullet compaction measurements downhole ≈.01 ft. The depth of investigation of radioactive bullets is small, about a foot or less. Since casing and cement serve to "reinforce" the formation near the borehole, conclusions about compaction using radioactive bullets in cased wells may not reflect conditions far from the borehole.

3. Effect of rock wettability (oil or water wet) and rock stress on estimates of water saturation from the resistivity log. It is desirable to know whether any free gas is present initially in formations considered for geopressured-geothermal testing. This is usually estimated from the resistivity log, since the formation resistivity increases as the water saturation decreases. Some previous work in the literature had reported very large increases in rock resistivity for a given water saturation as the rock became more oil wet. Our research showed that increasing rock stress increases rock resistivity moderately at a given water saturation. Making the rock oil wet produced a larger resistivity increase, but nothing like some of the extreme values that had been reported earlier.

4. Log interpretation in specific wells. The DOE Hulin Well, South Louisiana, is cited as an example. This is a deep (20,700 ft.), hot (360°F), high pressure (18,500 psi) well

with a thick sand extending from 20,220 to 20,690 ft. We carried out a computer based "Elan" analysis of this sand, which indicates that a small (probably irreducible) gas saturation exists over the entire sand section. This is surprising, and suggests that the gas accumulation may be recent (geologically speaking). If the free gas had been present for millions of years, diffusion through the water phase should have moved the gas from the bottom to the top of the sand. Gas production from this sand should be larger than it would be if no free gas were present.

5. Effect of trace amounts of boron on porosity estimates using the thermal neutron log. Boron is widely distributed in sediments, and cannot be detected by current logging tools. Trace amounts of boron can cause thermal neutron porosity estimates to be too high by several porosity units. Boron correlates with clay and can be estimated from correlations of boron with potassium or aluminum using the gamma spectral log and/or the geochemical log. Some cement additives contain large amounts of boron (pozzolan, fly ash). A study of boron in hydropressured and geopressured formations shows that correlations for boron corrections developed using data from hydropressured formations will also be useful in geopressured formations. This is important, since there is a lot more hydropressured data than geopressured data. Getting the right porosity is important, since errors here carry over directly into errors in the gas resource estimate.

6. Evaluation of a geopressured-geothermal prospect. This was a tutorial presented to a group of independent oil operators and investors attending a meeting of the Industrial Consortium for Utilization of Geopressured-Geothermal Resource, at U.T. Balcones Research Center, September 19, 1990. It outlines the essential features of Monte-Carlo modelling to obtain the expected present worth of a given project, and points out the desirability of using a cascaded series of direct heat applications, moving from higher to lower temperatures, in addition to sale of the dissolved gas.

7. Peer review of research. On April 28 - May 1, 1992, the Office of Program Analysis (OPA), Office of Energy Research (OER) of the Department of Energy (DOE) carried out a peer review assessment of research projects in the Geothermal Energy Program. We have heard informally that our report was well received by the Assessment Committee. Material submitted to the Assessment Committee, plus hard copies of the overheads used for the oral presentation, are attached as an appendix to this report.

Introduction:

The DOE Geopressured-Geothermal Energy Project has as its objective the evaluation of the energy resources potentially available from the hot, high pressured brines found along the Texas-Louisiana Gulf Coast. These brines contain energy in the form of heat (temperatures up to 400°F), dissolved gas, (mostly methane, 20 to 30 standard cubic ft/barrel of brine), and pressure (surface flowing pressure of several thousand psi at rates of 10,000 to 20,000 barrels/day). Estimating the amount of energy in specific reservoirs prior to production depends heavily on log analysis, which can be used to estimate porosity, initial gas saturation (if any), and formation water salinity. (As the water salinity increases, the methane solubility decreases.) Various aspects of our research are discussed in more detail below.

Specific Research Projects

1. Estimation of formation water salinity. In the early stages of the project, 1979 and earlier, reviews of abandoned wells drilled by the petroleum industry were made to identify possible candidates for testing. These "wells of opportunity" could often be tested at

relatively small cost, and could be used to evaluate the amount of dissolved gas in the formation brine. Usually the brine is saturated with gas, but the saturation value is a direct function of brine salinity, which varies considerably from one formation to another. The self potential log is often used to estimate salinity, but the estimates of salinity for the geopressured wells proved to be often wrong by 50% or more[1]. Our research showed that the error is mainly due to use of an incorrect value of mud filtrate resistivity, which can vary considerably from one day to the next as the well is drilled. In the past, mud filtrate resistivity was measured only when the well was logged, once or at most a few times during drilling. Accurate results for mud filtrate resistivity (and formation water salinity) require daily measurements of mud filtrate resistivity[2,3,4].

2. Assessment of radioactive bullet logging as related to subsurface compaction measurements. Early in the life of the geopressured-geothermal project there was considerable concern about possible surface subsidence as a result of large volume brine production. (Actually, there has been no subsidence noted for the two wells which have produced the most brine. The Gladys McCall well has produced 27×10^6 barrels of brine, and the Pleasant Bayou well has produced 15×10^6 barrels with no evidence to date of surface subsidence for either well.)[5] We carried out an extensive literature review which indicated that radioactive bullets fired into the formation can be located by logging tools within about ±.01 ft. However, the compaction very close to the wellbore (1 ft. or less) may or may not reflect compaction conditions far removed from the wellbore, due to the local reinforcement provided by the casing and cement[6].

3. Effect of rock wettability and rock stress on estimates of water saturation from the resistivity log. If any free gas (non-dissolved gas) is present in the formation being tested, incorrect conclusions will be drawn about methane solubility, incorrect predictions of gas recovery will be made, and incorrect estimates of water permeability from core data (too high) will be made.

The basic equation for predicting water saturation from the resistivity log is due to Archie,

$$S_w^{\,n} = \frac{P^{-m} R_w}{R_t}$$

Where S_w = formation water saturation
P = formation porosity
R_w = formation water resistivity
R_t = formation resistivity
n = saturation exponent
m = cementation exponent

Values of n and m are normally in the range of 1.5 to 2.5, but some n values as large as 15 have been reported in the literature. Our work showed that high rock stress increases both m and n somewhat, but that the rock wettability (oil or water wet) has a large effect on n, but little or no effect on m. We found no n values greater than about 5, even for very oil wet rocks[7,8,9].

4. Log interpretations in specific wells. The interpretation carried out in the DOE Hulin #1, near Lafayette, Louisiana, is given as an example. This deep (20,000+ feet) hot

(350°F) well contains a relatively clean sand body from about 20,220 ft. to 20,690 ft. which had not been previously tested. Open hole resistivity logs run by Superior Oil Company in this well in the late 70's indicated small free gas saturations in this sand (20-30%), probably at or below the gas saturation which would permit gas to flow. We wanted to confirm this indication if possible, and recommended the running of the dual burst (TDT-P) pulsed neutron log, which would provide a water saturation estimate in the cased well, independent of resistivity logs, which cannot be run in cased wells. The pulsed neutron tool was only able to log the upper 30 ft. of the sand before a tool failure occurred. However, analysis of this upper section confirmed the previous indication of low (close to irreducible) gas saturation shown by the open hole logs.

A more sophisticated, computer-based analysis of the logs was then carried out, using our "Elite" workstation and "Elan" software[10]. These let us analyze for shale, bound water, sand, gas, and bulk water content using all the logs available, and let us test for consistency by comparing each log with a reconstructed log calculated from the remainder of the logs run. A "confidence level" is then calculated based on how well the observed logs match the calculated (reconstructed) logs. If any log shows a poor match between the observed and calculated versions, it can be dropped from the data set and the operation repeated to obtain a higher confidence level.

Cases were chosen to represent the expected range of variation for m (cementation exponent); n (saturation exponent); and Σ_{matrix} (neutron capture cross section for matrix): m = 1.8 and 2.0; n = 1.8 and 2.0; Σ_{matrix} = 5.0 and 4.25 capture units. Fixed values of other parameters used in the analysis were Σ_{gas} = 10 c.u. (methane); Σ_{shale} = 50 c.u.; Σ_{water} = 95 c.u.; ρ_{gas} = .285 gm/cc; ρ_{matrix} = 2.65 gm/cc; Δt_{matrix} = 51.5 µs/ft.

Results for the best case (highest confidence level) are shown in Figures 1 and 2, pp. 16 & 17. A few comments on the results follow. Gas was indicated at about irreducible saturation for all cases. The confidence level is rather low when all well logs (cased hole) are used, due mainly to the poor match between the observed and reconstructed neutron porosity log. (See Figure 1, pp. 16.) When the Elan analysis is repeated omitting the neutron porosity log, note the marked increase in confidence which is obtained. See bottom of Figure 2, Model IV, p. 17.

An Elan analysis was next run over the entire 20,200 - 20,700 ft. interval using only the open hole logs. (See Figure 3, p. 18.) We see that a low gas saturation is shown throughout the sand, but the confidence level is low. When the analysis is repeated omitting various logs, the confidence is greatest when the neutron log is omitted, and we see we still have a low gas saturation throughout the sand (Model III, Figure 4, p. 19).

We repeated the analysis assuming low density and high density condensates for the hydrocarbons instead of methane. We still calculate low saturations of hydrocarbons throughout this sand for these assumptions.

The effect of these low gas or condensate saturations will be observed only after the reservoir pressure begins to fall substantially. If there were no free gas in the reservoir, gas coming out of solution in the reservoir initially would be trapped in the pore space. Gas cannot flow until the saturation increases enough to reach irreducible. Gas coming out of solution up to this stage could not flow. If gas saturation approximately equal to irreducible gas is already in place, gas coming out of solution in the reservoir can begin to flow immediately. However, most of the pressure drop (and gas evolution) will initially occur in the tubing between the formation and the surface. Substantial pressure drop in the reservoir will not occur until many months after production starts. When the reservoir pressure does drop, the original, irreducible free gas in place will expand due to the reduced formation pressure and begin to contribute to gas flow, along with the gas coming out of solution from the water. The effect of this initial residual gas saturation will therefore not be substantial until substantial water production has occurred.

5. Effect of trace amounts of boron on porosity estimates using the thermal neutron log. Boron in trace amounts is widely distributed in Gulf Coast sediments, and can cause porosity estimates from the thermal neutron log to be too high by several porosity units if no correction is made for it. Boron can also cause significant over estimation of formation water saturation from pulsed neutron logs. The porosity error is more important for the geopressured-geothermal project, since porosity is directly proportional to amount of hot water in the reservoir. We have shown that it should be possible to correct old thermal neutron logs for the effect of boron by using correlations of boron with other logging tools (gamma-spectral log; geochemical log; epithermal neutron log). We have also shown that boron correlations in normally pressured formations are not significantly different from correlations in geopressured formations. This is important, since there are a lot more data available from normally pressured formations than from geopressured formations[11,12, 13,14].

The amount of boron in some cement additives, such as pozzolan, and fly ash, is great enough to cause cased well porosity estimates using the thermal neutron log to be too high by several porosity units even in the absence of formation boron[13,14].

6. Evaluation of a Geopressured-Geothermal Prospect. This paper was presented to a group of relatively unsophisticated investors who were interested in possibly exploiting a geopressured-geothermal reservoir. It introduces them to the idea of present worth, and discusses how risk can be assessed by using Monte Carlo computer modelling of the operation. With present gas prices being so low ($1.00/MCF±) the main attraction economically is direct use of the produced heat, preferably in a series of cascaded processes that require progressively lower temperature water[5].

7. Peer review of research. On April 29, 1992, I made a twenty minute presentation describing our logging research to an assessment committee appointed by the Office of Program Analysis of DOE. This was part of an overall review of all DOE sponsored research in geothermal energy. Copies of material submitted to the Assessment Committee several weeks in advance of the meeting, plus hard copies of the overheads used in the presentation, are attached as an appendix to this report (pp. 6-30).

I have received no official feedback from this presentation, but believe the report was well received from one or two informal comments afterward. From the standpoint of the researcher, the timing of this peer review is poor (at the termination of the project). There is nothing the researcher can do to modify his approach if the Review Committee believes that the research areas or techniques should be modified.

REFERENCES

1 Dunlap, H. F. and M. H. Dorfman, "Problems and Partial Solutions in Using the S.P. Log to Predict Water Salinity in Deep, Hot Wells," Fifth Geopressured-Geothermal Energy Conference, Baton Rouge, LA, Oct 1981.

2 Dunlap, H. F. and D. H. Williams, "Short Term Variations in Drilling Fluid Parameters: Their Measurements and Implications," The Log Analyst, Sept-Oct 1984.

3 Dupree, J. H., T. A. Lowe and H. F. Dunlap, "Effect of Makeup Water and Mud Additives on Drilling Fluid Resistivity," Sixth U. S. Gulf Coast Geopressured-Geothermal Energy Conference Transactions, Austin, TX, Feb 1985.

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5 Dunlap, H. F., "The Evaluation of a Geopressured-Geothermal Prospect," Industrial Consortium for Utilization of Geopressured-Geothermal Resource, Balcones Research Center, Univ of Texas, Sep 11, 1990.

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7 Dunlap, H. F., M. G. Lewis and M. M. Sharma, "Wettability and Stress Effects on Saturation and Cementation Exponents" SPWLA 29th Annual Logging Symposium, Jun 1988.

8 Dunlap, H. F., M. G. Lewis, M. M. Sharma and M. H. Dorfman, "Techniques for Measuring Electrical Properties of Sandstone Cores," SPE Paper 18178, SPE Annual Mtg., Oct 1988.

9 Sharma, M. M., A. Garrouch and H. F. Dunlap, "Effect of Wettability, Pore Geometry and Stress on Electrical Conduction in Fluid Saturated Rocks," The Log Analyst, Sep-Oct 1991. pp. 511-526.

10 Quirein, J., et. al. "A Coherent Framework for Developing and Applying Multiple Format Evaluation Models," SPWLA 27th Logging Symposium Proceedings, 1986, Paper DD.

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13 Dunlap, H. F. and G. R. Coates, "Boron in West Texas Formations and in Oil Well Cements," The Log Analyst, Jul-Aug 1990.

14 Dunlap, H. F., R. V. Everett and M. C. Quirein, "Analysis of Boron Effects on Wireline Estimates of Porosity and Gas Saturation in Tight Gas Sands," GRI Topical Report No. 92/0176, 1992, in press.

APPENDIX

Hard Copies of Of Overheads

Used in Oral Presentation to

Peer Review Committee

DOE GEOPRESSURED-GEOTHERMAL LOGGING RESEARCH

1. **Objectives:**
   - A. Provide advice on logging programs in DOE wells, monitor log quality during data acquisition and provide log analyses as requested by DOE.
   - B. Carry out research on logging problems important to DOE program (and to the petroleum industry).
   - C. Provide other services as skills and time permit ("Evaluation of a Geopressured-Geothermal Prospect").

2. **Staff:**
   - A. Principal Investigator: H. F. Dunlap
   - B. Manager and Coordinator: M. H. Dorfman
   - C. Graduate Students: Ali Garrouch
     Tom A. Lowe
     Huw Williams
     H. F. Dupree
     M. G. Lewis

GEOPRESSURED-GEOTHERMAL LOGGING RESEARCH

Project: Funding and Duration

Year	DOE/ Logging Direct Research Funding	DOE Overhead	GRI Direct Research Funding	GRI Overhead
1979-80	~$37,000	~$13,000		
1980-81	~$37,594	~$12,406		
1981-82	~$37,037	~$12,963		
1982-83	~$36,232	~$13,768		
1983-84	~$35,461	~$14,539		
1984-85	$37,000	$15,170		
1985-87	$42,667*	$18,773*		
1987-88	$68,493	$31,507		
1988-89	$64,552	$29,694		
1989-90	$68,493	$31,507	$4,401	$2,024
1990-91	$69,499	$32,156	$4,707	$2,212

*Allocation of funds by year uncertain due to late funding by DOE.

Logging Project: Research Areas

Year	Research Items
1979-86	Improving methods of predicting formation water salinity from the self potential log.
1980	Assessment of radioactive bullet logging as related to subsurface compaction measurements.
1986	Effect of rock stress and rock wettability (oil or water wet) on estimates of water saturation.
1979-91	Providing specific advice and log analysis on DOE wells of interest.
1987-91	Effect of boron on porosity estimates from the thermal neutron log
1990	Economic evaluation of geopressured-geothermal prospects.

PREDICTION OF WATER RESISTIVITY (SALINITY)

FROM SELF POTENTIAL LOGS

$$\text{Basic Equation:}\quad \text{S.P.} = K\log_{10}\frac{R_{mf}}{R_w}$$

Important Since:

1. Methane solubility decreases as formation water salinity increases.
2. Formation water salinities vary considerably.
3. Estimates of R_{mf} were made from measurements using a mud sample taken when the well was logged.
4. Estimates of R_w (salinity) were typically in error by 50% or more.

Our research showed:

1. R_{mf} can vary considerably from one day to the next. Daily measurements of R_{mf} are needed for good estimates of R_w (see papers 11-14 attached to Dunlap's resume), p. 30.

ASSESSMENT OF RADIOACTIVE BULLET LOGGING AS RELATED TO SUBSURFACE COMPACTION MEASUREMENTS

This research was done because of environmental concerns about possible surface subsidence resulting from large volume brine production:

1. Extensive literature research established accuracy of compaction measurements down hole: ≈±.01 ft. (no experimental work done).
2. Depth of investigation of radioactive bullets is small - about a foot or less.
3. Casing and cement serve to "reinforce" the formation near the borehole, so conclusions about compaction using radioactive bullets in cased wells may not reflect conditions far from the wellbore.

EFFECT OF ROCK WETTABILITY (OIL OR WATER WET) AND ROCK STRESS ON ESTIMATES OF WATER SATURATION

It is desirable to know whether any free gas is initially present in wells considered for geopressured-geothermal testing.

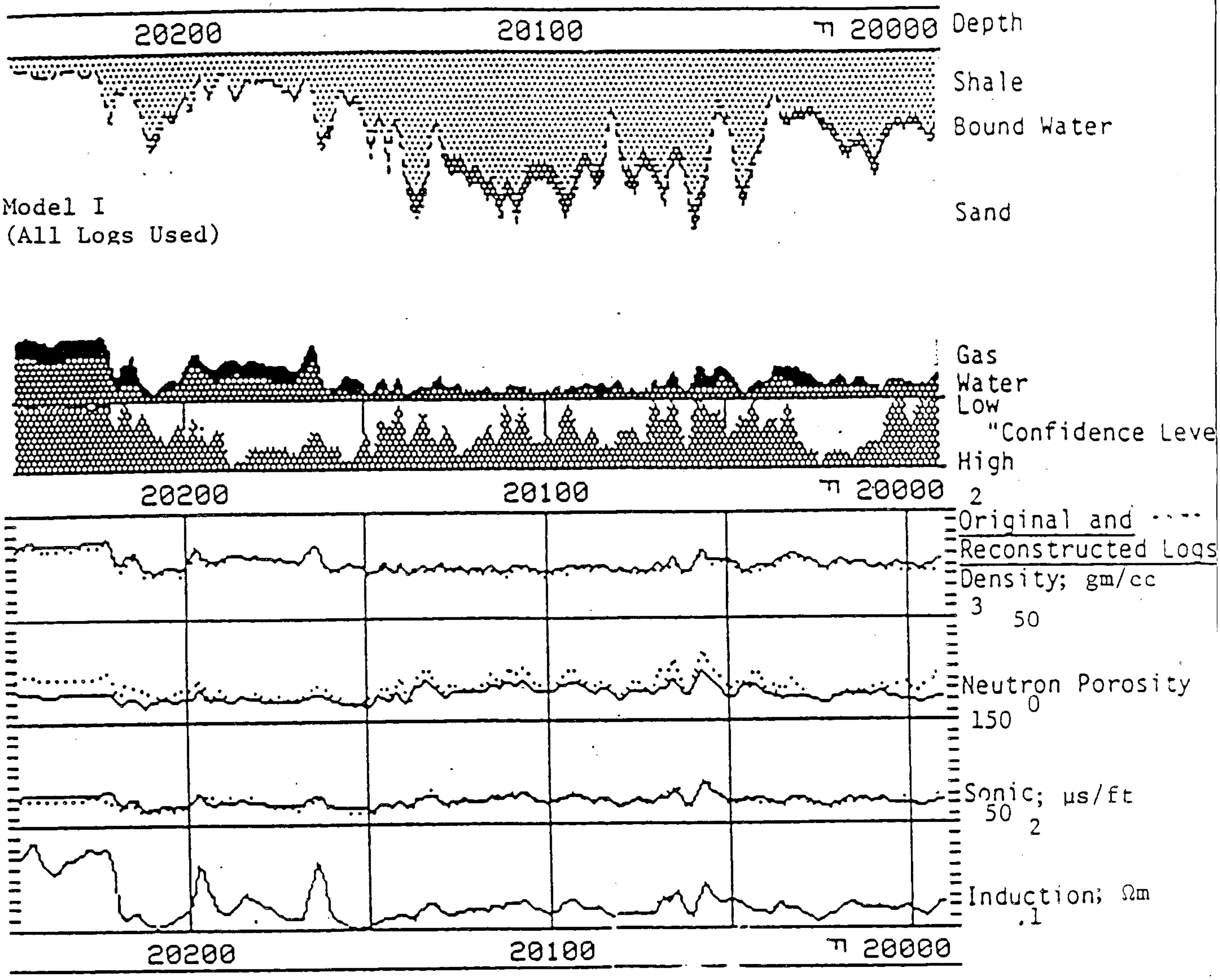
$$\text{Basic Equation: } S_W^n = \frac{P^{-m} R_W}{R_t}$$

We can estimate P, R_W, and R_t from well logs. However, we know that exponents m and n vary with rock stress, and with rock wettability. Normally, m and n range from values of 1.5 to 2.5, but some reports of n values >15 appear in the literature for oil wet rocks. Our work showed no n values greater than about 5. (See papers 9 and 10, listed on second page of Dunlap's resume.) In general we find that large rock stress increases both m and n moderately. Rock wettability has no effect on "m," but oil wet rocks will have a substantially larger "n" value than equivalent water wet rocks.

LOG INTERPRETATION IN SPECIFIC WELLS

DOE HULIN #1

The DOE Hulin #1, Vermillion Parish, Louisiana, is a deep (20,700 ft), hot (360°), high pressure (18,500 psi) well with a thick sand extending from 20,220 to 20,690 ft. Pages 4 and 5 of Reference 5 give details of the "Elan" computer-based log analysis we carried out here. Figures 1 through 4 from Reference 5 show the results indicating small (probably residual) saturations of free gas throughout this sand. Note the increase in confidence when the CNL log is dropped from the analysis. This may indicate boron is a problem here.



Parameters Used:

Σ_m = 5.0 c.u.

Σ_H = 10.0 c.u. (methane)

m = 2.0

n = 2.0

Σ_{shale} = 50 c.u.

Σ_{water} = 95 c.u.

ρ_{ma} = 2.65 gm/cc

ρ_{gas} = .285 gm/cc

Δt_{ma} = 51.5 μs/ft

Figure 1: Elan Analysis, DOE Hulin #1 Well

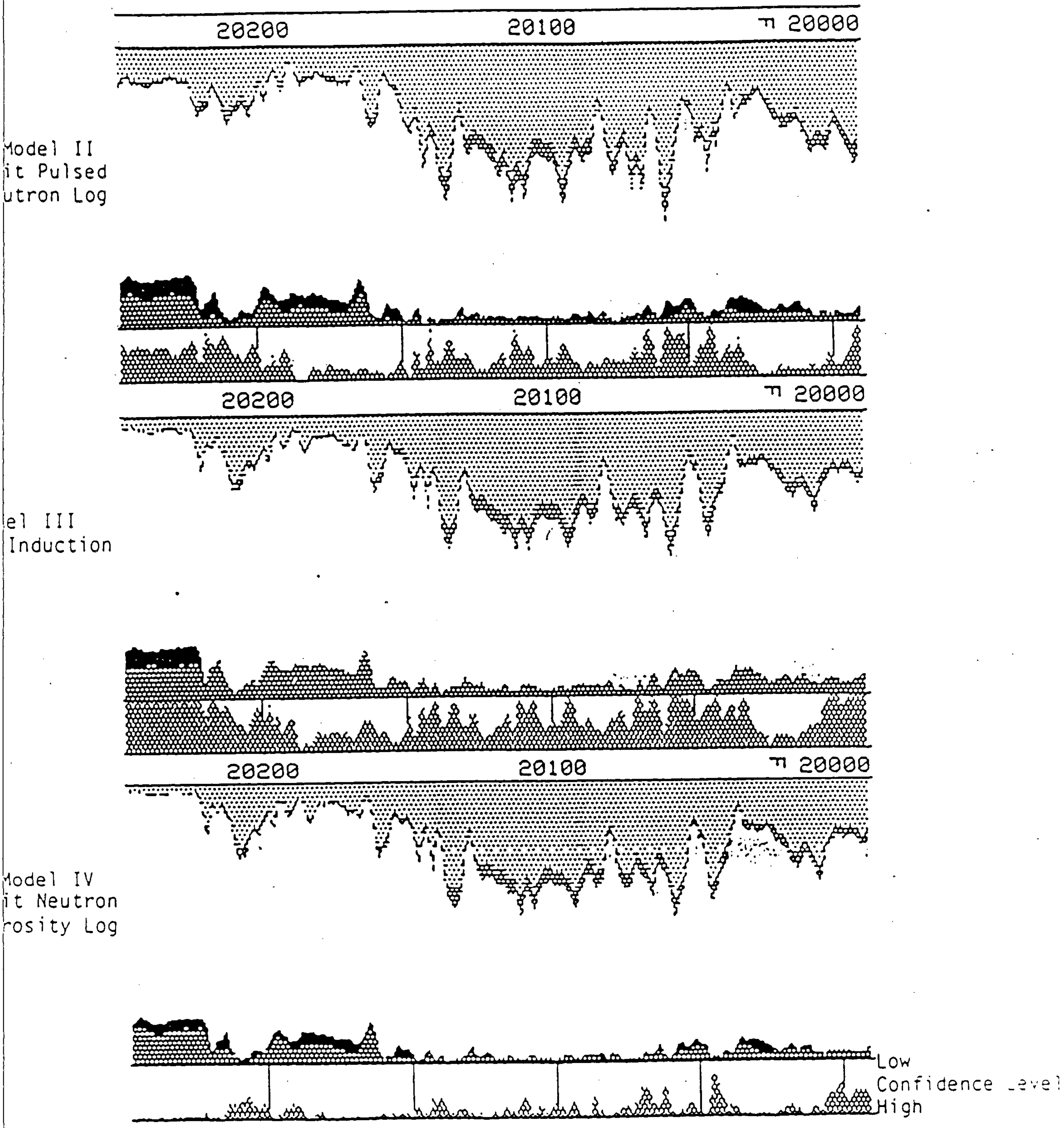
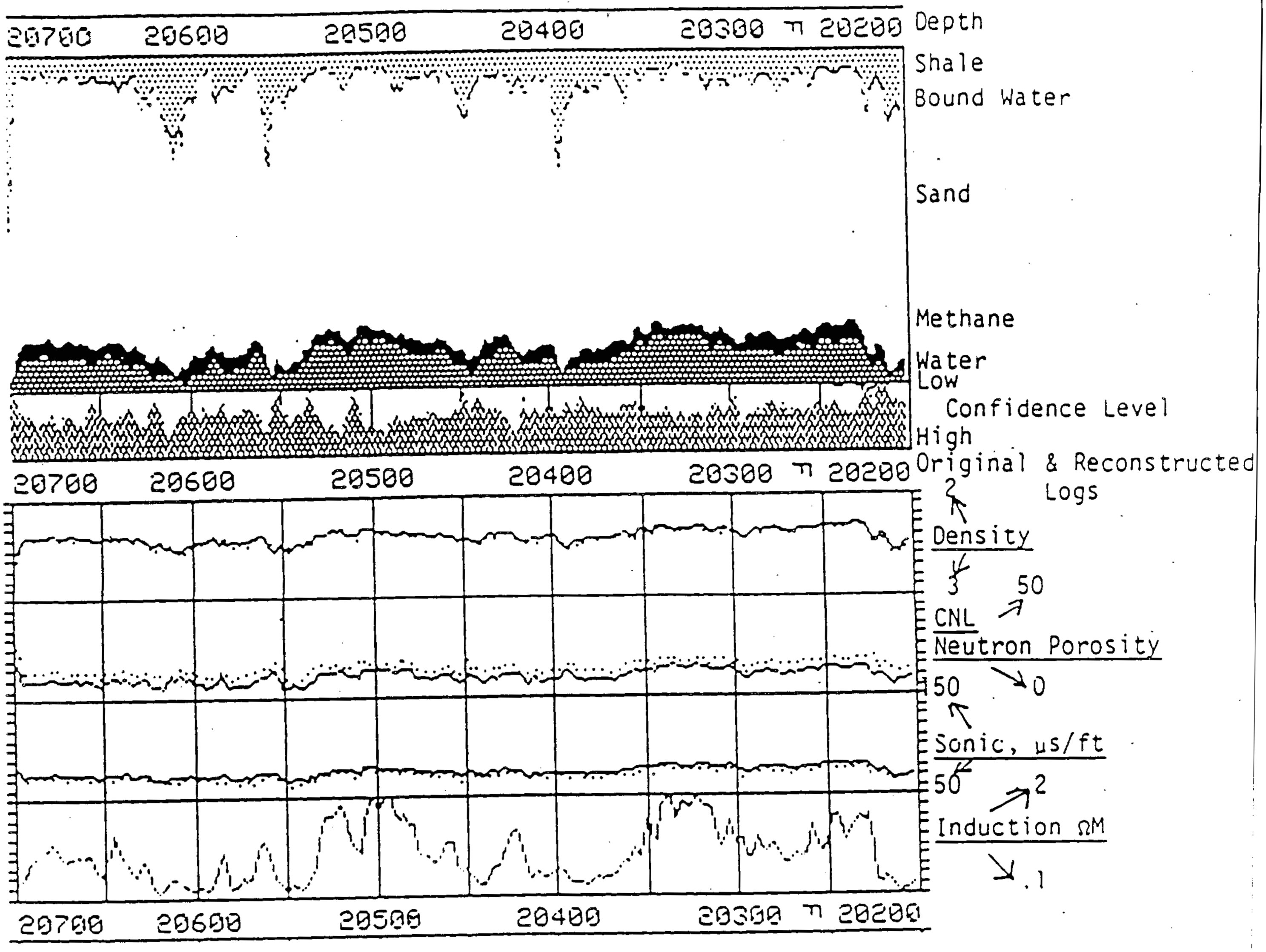


Figure 2: Elan Analysis, DOE Hulin #1 Well
Case I (Σ_m = 5.0 c.u.; m = 2.0, n = 2.0)



Parameters Used:

$\Sigma_m = 5.0$ c.u.

$\Sigma_H = 10.0$ c.u. (methane)

$m = 2.0$

$n = 2.0$

$\Sigma_{shale} = 50$ c.u.

$\Sigma_{water} = 95$ c.u.

$\rho_{ma} = 2.65$ gm/cc

$\rho_{gas} = .285$ gm/cc

$\Delta t_{ma} = 51.5$ µs/ft

Figure 3: Elan Analysis, DOE Hulin #1 Well (Methane)
Model I - All Open Hole Logs Used

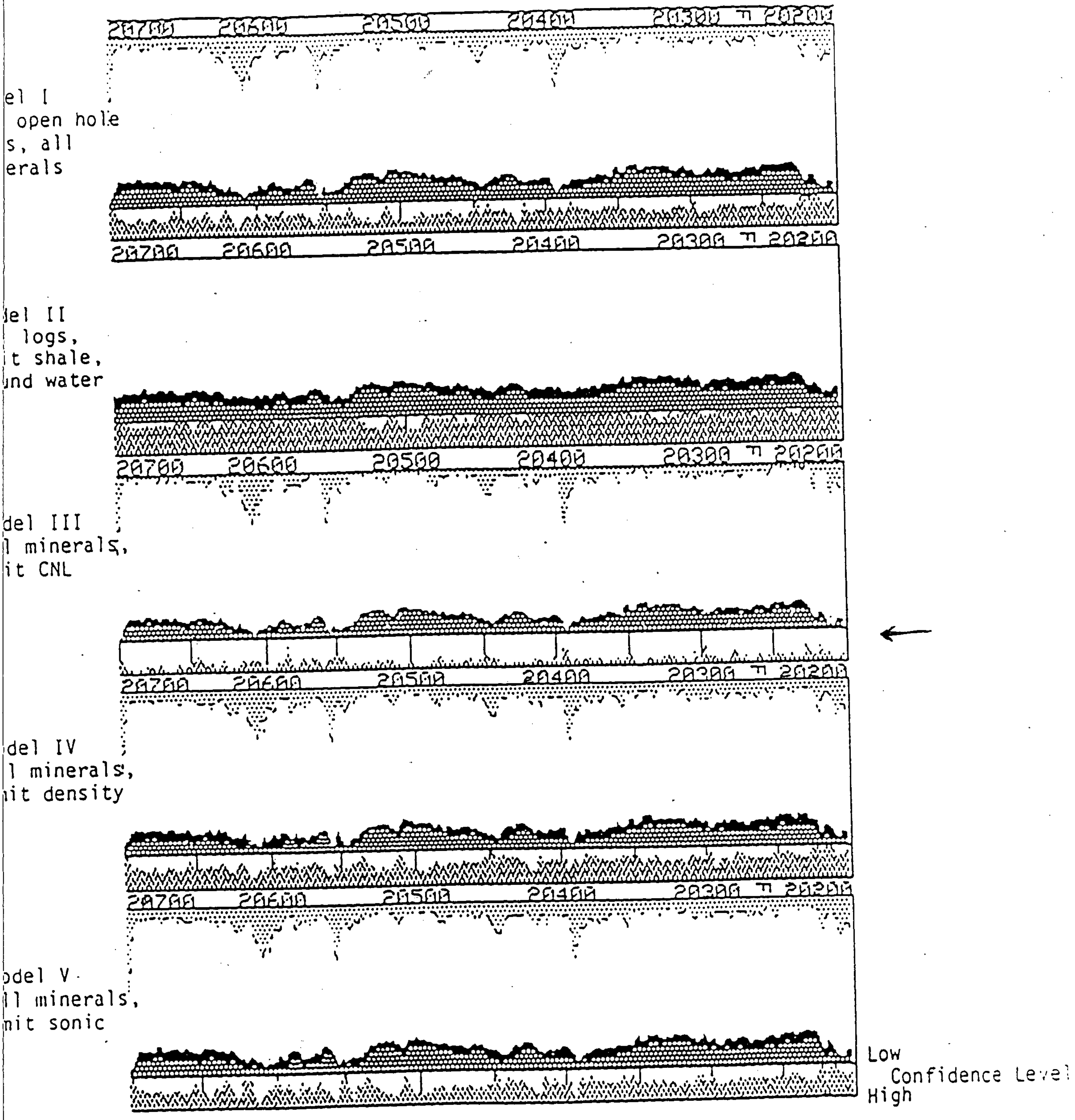


Figure 4: Elan Analysis, DOE Hulin #1 Well (Methane)
Change in confidence levels when delete
various logs or mineral constituents from model.

RECENT RESEARCH: EFFECT OF TRACE AMOUNTS OF BORON ON POROSITY ESTIMATES USING THERMAL NEUTRON LOG

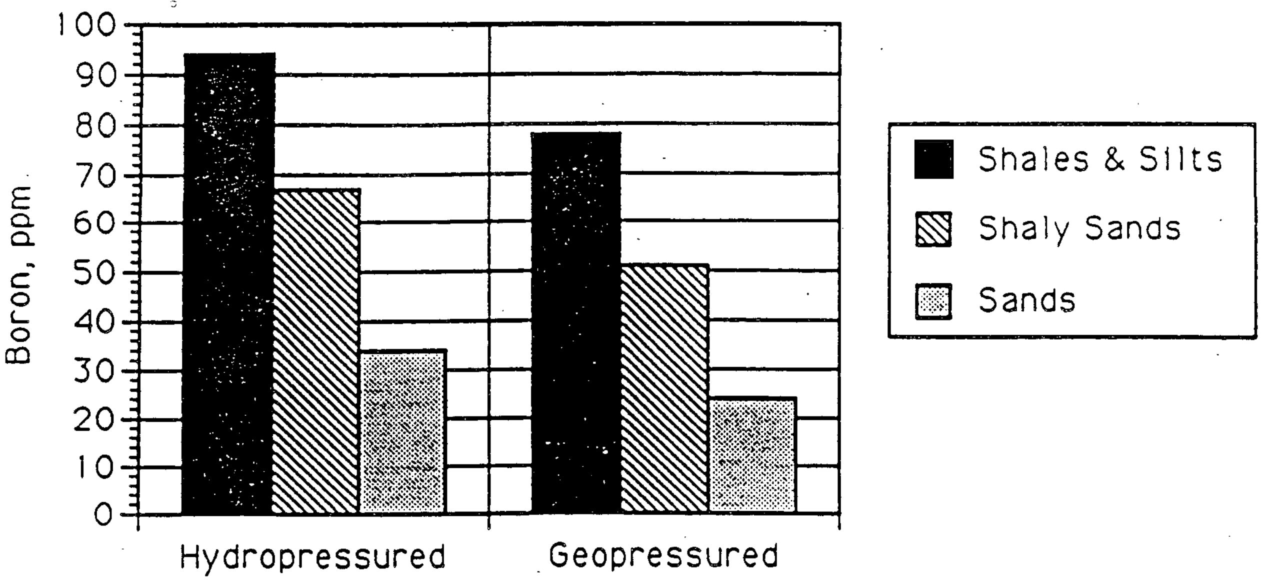
1. Trace amounts of boron can cause thermal neutron porosity estimates to be too high by several porosity units (See Abstract, Reference 14, p. 6).
2. Boron can cause significant overestimation of water saturation from pulsed neutron logs.
3. Boron is widely distributed in sediments and cannot be detected by current logging tools.
4. Boron correlates with clay, and can be estimated from correlations of boron with K and Al using the gamma-spectral log and/or the geochemical log.
5. Some cement additives contain large amounts of boron (pozzolan, fly ash).
6. Study of boron in hydropressured and geopressured formations shows that correlations for boron corrections developed using hydropressured data will also be useful in geopressured formations (See Figure 1, Reference 12, p. 6).

ANALYSIS OF BORON EFFECTS ON WIRELINE ESTIMATES OF POROSITY AND GAS SATURATION IN TIGHT GAS SANDS

ABSTRACT

Boron in trace amounts causes both the compensated thermal neutron log and the thermal pulsed neutron log to overestimate porosity by as much as several porosity units. Boron can also cause large overestimations of water saturation when using the pulsed neutron log. Boron cannot be measured directly by any currently available logging tool. Corrections for boron must depend on elemental analysis of cores or on correlations of boron with log-derived variables such as Al, K or the gamma log. Studies of these correlations in 5 GRI wells plus an additional well reported in the Bulletin of AAPG (June 1990) showed that useful estimates of boron content can be obtained from such correlations. Also, the correlations seem to be valid over at least a mile in East Texas and perhaps as much as five miles in Wyoming. Correlations of epithermal versus thermal neutron logs look especially promising since they avoid the problems of core-to-log depth mismatch and sample size variation, core versus log. They account not only for boron but for other high capture cross section elements such as gadolinium, chlorine, etc. Pozzolan is often used as a cementing additive in amounts up to 50% when cementing oil wells. It contains a lot of boron. The GRI SFE #4 well was completed using a 50/50 pozzolan-cement mix. The average openhole thermal neutron porosity in the perforated interval of this well was 4 p.u. lower than the average casedhole value (10.7 p.u. versus 14.7 p.u.).

Figure 1. Average Boron Vs. Lithology*



*From Reference 12, p. 6.

Material Submitted to
Peer Review Committee Prior
to Oral Presentation

GEOPRESSURED-GEOTHERMAL ENERGY PROGRAM
GEOSCIENCE AND ENGINEERING SUPPORT

1. Project Title: Logging Research for DOE Geopressured-Geothermal Project

Principal Investigator:	H. F. Dunlap
Organization:	Center for Petroleum and Geosystems Engineering
Address:	The University of Texas CPE 2.502 Austin, TX 78712
Telephone:	512/471-3161

2. Patentable or Potentially Patentable Inventions

"I am an owner, officer, or employee of a university, not-for-profit organization, or small business, and the information provided below contains information, data, or material pertaining to an invention, or inventions, made under a Government-funded contract grant that I believe is potentially patentable."

not applicable

3. Principal Project Personnel

A. Principal Investigator: H. F. Dunlap
B. Principal areas of research and expertise: well logging, petrophysics, petroleum economics
C. Percent of time devoted to project: 30%
D,E,F Education; relevant employment history; and professional honors and awards: See attached resume.
G. Relevant publications not emanating from this project:

"Economic Analysis of a Geothermal Exploration and Production Venture," Proceedings of Second United Nations Symposium on Geothermal Resources, San Francisco, California, May 1975 (with T. K. Juul-Dam) pp. 2315-24.

"Importance of Early Development of Nuclear Stimulation Process," presentation at Atomic Industrial Forum Annual Meeting, San Francisco, California, Dec 1969.

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"Research and Progress in Exploration," Geophysics, Apr 1958, p. 267 (with C. H. Johnson).

"Geophysical Research Progress in Exploration," Geophysics, Apr 1957, p. 412 (with M. B. Dobrin).

"The Calculation of Water Resistivities from Chemical Analyses," Jour. Pet. Tech., Sec 1, Mar 1951, p. 17 (with R. R. Hawthorne).

"The Scattering of Neutrons by Helium and the D-D Spectrum," Phys. Rev., Nov 1941, p. 693 (with R. N. Little).

"Anomalous Scattering of Neutrons by Helium and the D-D Spectrum," Phys. Rev., Jun 1940, p. 971 (with E. Hudspeth).

"Low Energy Neutrons from D-D Reaction, Phys. Rev., Mar 1939, p. 587 (with E. Hudspeth).

4. Additional Project Personnel

A. Members of the technical staff: Dr. Myron H. Dorfman, Coordinator and Advisor (see attached resume).
Graduate Students: J. H. Dupree, Ali Garrouch, M. G. Lewis, T. A. Lowe, D. H. Williams

B. Collaborators on the project: None

5. Project Overview

A. Specific Project Objectives

1. Past

1979-1986; Improving methods of predicting formation water salinity from the self potential log.

1980; State-of-the-art of radioactive bullet logging as it relates to subsurface compaction measurements.

1986-1991; Effect of rock wettability (oil or water wet) and rock stress on estimates of water saturation.

1979-1991; Providing specific advice and log analysis on DOE wells of interest.

2. Current

1987-1991; Effect of boron and other high thermal neutron capture cross section trace elements on porosity estimates using the thermal neutron log.

1990; Economic evaluation of geopressured-geothermal prospects.

3. Possible future work

A project titled "Detection of Water Influx from Adjacent Shales Using Well Logs" is being submitted for DOE support, jointly with Dr. Steve Morriss, Assistant Professor, Department of Petroleum Engineering, The University of Texas, Austin, Texas. (See attached description.)

B. The logging research and advisory effort has been valuable to the DOE mission by (a) developing improved log interpretation methods (better water salinity and porosity estimates); (b) providing advice on proper logging packages to run in DOE wells, providing on-site monitoring of log acquisition to assure quality data, and in providing log analyses as requested.

C. How this project relates to other projects beings funded by DOE. No information.

D. Project History

1. Previous and current funding
Current funding: none
Previous funding: Logging Research Only

Year	DOE/Logging Direct Research Funding	DOE Overhead	GRI Direct Research Funding	GRI Overhead
1979-80	~$37,000	~$13,000		
1980-81	~$37,594	~$12,406		
1981-82	~$37,037	~$12,963		
1982-83	~$36,232	~$13,768		
1983-84	~$35,461	~$14,539		
1984-85	$37,000	$15,170		
1985-86 & 1986-87	$42,667 *	$18,773 *		
1987-88	$68,493	$31,507		
1988-89	$64,552	$29,694		
1989-90	$68,493	$31,507	$4,401	$2,024
1990-91	$69,499	$32,156	$4,707	$2,212

*Allocation of funds by year uncertain due to late funding by DOE.

6. Scientific and Technical Content

A. Relation of this research to other research in this field. This research supplements ongoing research in the oil industry. (Reliable log-derived values of porosity, water saturation, and formation water salinity are essential to log interpretation and reservoir analysis.)

B. Importance of solving the problem being addressed by this research. (See 6A, above).

C. Schedule of major research activities. (See 5A, above).

D. Scientific or technical issues currently being addressed. (None - See 5A3, above).

E. Experimental and theoretical approach taken, techniques used, and resources applied. See list of papers with Dunlap's resume (attached). These papers are all the result of our DOE effort.

7. Project Output

A. Major recent accomplishments
Recent work has been on the effect of boron and other high capture cross section elements on porosity estimates from the thermal neutron log. We have shown that boron is widely distributed in both hydropressured and geopressured formations, and in some types of cement additives. The "boron effect" can cause errors of several porosity units for estimates made using the thermal neutron log. The "boron effect" on the pulsed neutron log is to make water saturation estimates from the pulsed neutron log too high. (See references attached).

B. Bibliography of publications emanating from this project.
See list of papers attached to Dunlap's resume.

HENRY F. DUNLAP
Adjunct Professor
Department of Petroleum Engineering
The University of Texas
Austin, TX 78712
512/471-3161 (office)
512/847-2162 (home)

EDUCATION

Ph.D., Physics, Rice Institute, 1941
M.A., Physics, Rice Institute, 1939
B.A., Physics, Rice Institute, 1938

INDUSTRIAL EXPERIENCE

Atlantic-Richfield Company (Research Dept.), 1945-75

EDUCATIONAL EXPERIENCE

Adjunct Professor, The University of Texas, 1976-present
Lecturer in Physics, The University of New Mexico, 1942-1945

HONORS AND AWARDS

American Men & Women of Science
Who's Who in South and Southwest
Who's Who in Commerce and Industry
U.S. Navy Award for "exceptional service" to naval ordinance development

MEMBERSHIPS

Society of Petroleum Engineers of AIME
Society of Professional Well Log Analysts
American Physical Society
Society of Exploration Geophysics
American Association of Petroleum Geologists
Sigma Xi

CONSULTING

Core Labs; University of Port Harcourt, Nigeria; Republic Energy Company; World Bank; Bureau of Standards

PUBLICATIONS (RECENT)

1. "Boron in Geopressured-Geothermal Formations and in Casing Steels," (with G. R. Coates), The Log Analyst, Nov-Dec 1991, pp. 671-674.
2. "Analysis of Boron Effects on Wireline Estimates of Porosity and Gas Saturation in Tight Gas Sands," (with R. V. Everett and M. C. Quirein), GRI Topical Report 92/0176, in press, 1992.
3. "Effect of Wettability, Pore Geometry and Stress on Electrical Conduction in Fluid Saturated Rocks," SPWLA Meeting, Feb 21, 1991.

4. "The Evaluation of a Geopressured-Geothermal Prospect," Industrial Consortium for Utilization of Geopressured-Geothermal Resource, The University of Texas, Balcones Research Center, Sep 11, 1990.
5. "Boron in West Texas Formations and in Oil Well Cements," (with G, R. Coates), The Log Analyst, Jul-Aug 1990.
6. "Well Logging Research for the Department of Energy Geopressured-Geothermal Project," (with M. H. Dorfman), Geothermal Resources Council Transactions, Vol 14, Part 1, Aug 1990.
7. "An Overview of Recent Logging Research at The University of Texas, Petroleum Engineering Department," Geothermal Program Review VII, San Francisco, CA, 1989.
8. "Boron - Tracking a Trace Element" (with G. R. Coates), The Log Analyst, Nov-Dec 1988.
9. "Techniques for Measuring Electrical Properties of Sandstone Cores" (with M. G. Lewis, M. M. Sharma, M. H. Dorfman), SPE Paper 18178, SPE Annual Mtg., Oct 1988.
10. "Wettability and Stress Effects on Saturation and Cementation Exponents" (with M. G. Lewis, M. M. Sharma), SPWLA 29th Annual Logging Symposium, Jun 1988.
11. "Estimation of Mud Filtrate Resistivity in Fresh Water Drilling Muds" (with T. A. Lowe), The Log Analyst, Mar-Apr 1986.
12. "Effect of Makeup Water and Mud Additives on Drilling Fluid Resistivity," (with J. H. Dupree, Jr. and T. A Lowe), 6th U. S. Gulf Coast Geopressured-Geothermal Energy Conference Transactions, Austin, Texas, Feb 1985.
13. "Short-Term Variations in Drilling Fluid Parameters: Their Measurement and Implications" (with D. H. Williams), The Log Analyst, Sep-Oct 1984.
14. "Problems and Partial Solutions in Using the S.P. Log to Predict Water Salinity in Deep Hot Wells," (with M. H. Dorfman), Fifth Geopressure-Geothermal Energy Conference, Baton Rouge, Louisiana, Oct 1981.
15. "Review of State of Art of Radioactive Bullet Logging as it Relates to Subsurface Compaction Measurements," (with M. H. Dorfman), Final Report to Lawrence Berkeley Laboratory, Contract No. 6639102, Center for Energy Studies, The University of Texas at Austin, Mar 1980.
16. "Relation Between Electrical Resistivity and Brine Saturation in Reservoir Rocks" (with H. L. Bilhartz, E. Shuler, and C. R. Bailey), Petroleum Transactions, AIME, Oct 1949, p. 259.

Total publications: 25
Patents issued: 28

CONTRACTS AND GRANTS

Chevron, 1980-81, 1981-82, Grant in support of work on log interpretation in wells with high density muds.

M.S. SUPERVISED: 4

AREAS OF INTEREST

Well Logging, Geology, Geophysics, Petroleum Economics

MYRON H. DORFMAN
W. A. (Tex) Moncrief, Jr.
Centennial Endowed Chair in Petroleum Engineering

PROFESSIONAL REGISTRATION

Registered Professional Engineer in Texas #33428
Certified Professional Geological Scientist - AIPG, #7335

EDUCATION

Ph.D., Petroleum Engineering, The University of Texas at Austin, 1975
M.S.P.E., The University of Texas at Austin, 1972
B.S.P.E., The University of Texas at Austin, 1950
Rice University, Houston, TX, 1943-1944

PROFESSIONAL EXPERIENCE

Acting Director, Center for Petroleum & Geosystems Engineering, 1987-1989.
Director, Texas Petroleum Research Committee, Texas Railroad Commission, 1982-1986.
Chairman, Department of Petroleum Engineering, The University of Texas at Austin, 1978-1985.
Professor, Department of Petroleum Engineering, The University of Texas at Austin, 1978-present.
Director for Geothermal Studies, Center for Energy Studies, The University of Texas at Austin, 1974-1989.
Associate Professor, Department of Petroleum Engineering, The University of Texas at Austin, 1976-1978.
Assistant Professor, Department of Petroleum Engineering, The University of Texas at Austin, 1974-1976.

OTHER EXPERIENCE

Oil and Gas Producer, Consulting Engineer and Geologist, Dorfman Oil Properties and Dorfman Production Company, Shreveport, Louisiana, 1959-1971.

HONORS AND AWARDS

W.A. "Tex" Moncrief Jr. Centennial Chair in Petroleum Engineering, 1983 to present
H.B. "Burt" Harkins Professor of Petroleum Engineering, 1980-1983
Chairman, Geothermal Advanced Systems Advisory Committee, Dept. of Energy, 1986
Chairman, Cedric Ferguson Medal Committee, Society of Petroleum Engineers, 1986-1987
Hearst Distinguished Lecturer, University of California, Berkeley, Spring 1986
International Advisory Board, In-Situ, 1986 to present
International Editorial Board, Journal of Geothermal Science and Technology, 1987 to present
Master Lecturer, 3rd Latin American Petroleum Congress, Caracas, Venezuela, 1984
Who's Who in Frontier Science and Technology, 1984, 1986
Who's Who in Engineering, 1982-1986, 1989
Who's Who in Finance and Industry, 1978, 1981
Who's Who in the South and Southwest, 1975
Who's Who in the World, 1980, 1982, 1986, 1989

Who's Who in America, 1982, 1984, 1986, 1989
International Who's Who in Engineering, 1984 , 1986
National Academy of Sciences, Yugoslavia, 1973
Fellow, Geological Society of America, 1973
Pi Epsilon Tau, 1972
Tau Beta Pi, 1976
Phi Kappa Phi, 1977
Interstate Oil Compact Commission, 1959-1965, 1976 to present, (appointed by the governor)
SPE Distinguished Lecturer, 1978-1979
SPE Distinguished Author, 1982
Sigma Xi, The Scientific Society, 1981
American Men and Women of Science, 1982
Research Coordination Council, Gas Research Institute, 1983 to present
Over 50 publications on Geopressured-Geothermal Energy and Formation Evaluation.

SELECTED PUBLICATIONS

Articles and Reports:

"Well Logging Research for the DOE Geopressured-Geothermal Project," (with H. F. Dunlap), Proceedings: Geothermal Resources Council 1990 International Symposium on Geothermal Energy, Kailua-Kona, Hawaii, Aug. 1990.

"The Geopressured-Geothermal Resource: Transition to Commercialization," (with J. Negus-de Wys), Proceedings: Geothermal Resources Council 1990 International Symposium on Geothermal Energy, Kailua-Kona, Hawaii, Aug. 1990.

"Geopressured Geothermal Energy and Natural Gas," Proceedings: Geothermal Energy Symposium, ASME ETC, New Orleans, 1988, pp. 97-102.

"New Techniques in Lithofacies Determination and Permeability Prediction in Carbonates Using Well Logs," (with Newey and Coates), 1988, The Geological Society, Burlington House, London.

"Techniques for Measuring Electrical Properties of Sandstones Cores," SPE #18178 (w. Sharma, Dunlap) SPE Annual Meeting, Oct. 1988.

"The Microresistivity Log and Tight Gas Sands, East Texas Basin," (w. Coates) The Log Analyst, 1988.

"Geothermal Energy Technology - Issues, R & D Needs, and Cooperative Agreements," (with Committee Members), National Research Council, National Academy of Science, Dec. 1987.

"An Overview of Geopressured Geothermal Energy Research," Proceedings Geothermal Program Review V, DOE, 1987, pp. 85-91.

"Identification of Carbonate Depositional Texture from Well Log Response-West Seminole Field, Gaines County, Texas", (with K. Kamon), Proceedings, Permian Basin Research Conference, Society of Economic Paleontologists and Mineralogists, PBS-SEPM Pub.#86-26, pp.75-78, Oct. 1986

"New Techniques for Facies Determination in Carbonate Reservoirs Using Well Logs," (with J. DuPree), Proceedings, 3rd European Oil Recovery Conference, Rome, Vol. I, pp. 13-23, April 1985.

"Discussion of Reservoir Description Using Well Logs," Journal of Petroleum Technology, v. 36, no. 13, December 1984, pp. 2195-96.

"Facies Characterization of Carbonates by Use of Well Logs, Sligo Formation (Lower Cretaceous), South Texas," Transactions, SPWLA, 1983 (with W.H.M. Basham).

Books, Chapters of Books:

Geopressured Geothermal Energy, (editor), Pergamon Press, New York, 1985.

Invited Papers:

"Geopressured Geothermal Energy & Associated Natural Gas," Proceedings Geothermal Energy Syposium, ASME Energy Technology Conference, New Orleans, 1/88, pp. 97-102.

Proposal for Future Work

"Detection of Water Influx from Adjacent Shales Using Well Logs"

(We understand there are no plans to fund this project at present.)

2. DETECTION OF WATER INFLUX FROM ADJACENT SHALES USING WELL LOGS

Introduction

A major unsolved problem in the DOE GEOPRESSURED-GEOTHERMAL project is the smaller than expected pressure decline after large water production in the Gladys McCall well. Several possible reasons for this have been discussed, including (a) leaks across assumed "sealing" faults that bound the reservoir, and (b) water influx from the shales above and below the reservoir as pressure declines. One way to test the second hypothesis is to analyze well logs for shale porosity just above and just below the producing zone. Using data from sonic logs, thermal and epithermal neutron logs, and the pulsed neutron log, we should be able to detect changes in shale porosity near the producing well. This is where the pressure difference between the producing zone and the adjacent shales would be greatest, and the largest difference in shale porosity would be expected.

We may not be able to detect this effect in the Gladys McCall well, which has been shut in for a year or two already. The pressure drop between the water in the adjacent shales and the producing zone is much less than it was immediately after production stopped, and some reverse flow of the water back into the shale may have taken place. A better candidate to study this effect may be the Pleasant Bayou #2 well, which has only recently been shut in. If long term testing of the Hulin well at high flow rates is done, this would be the ideal place to test the hypothesis.

Comparison of porosity of shales lying directly above and below the producing zone with porosity of shales higher up in the well would also be important to establish a baseline since some change in the borehole environment since the original logs were run is to be expected. Any differences remaining after performing borehole corrections can be used as a basis for normalization. Both acoustic and neutron logs are quite sensitive to changes in water content in shales, so small changes should be apparent on the logs.

The strategy therefore is to run acoustic and neutron logs identical to those run before production commenced, perform environmental corrections using the Schlumberger Atlantis workstation, and compare the results before and after to see if there are changes. If there are, we will quantify them in terms of water volumes and compare these results to production. The variation in the changes with distance away from the reservoir will also be analyzed.

Objectives

The objective of the proposed research is to determine if there has been significant water influx from adjacent shales as the pressure has declined in a geopressured-geothermal well. The best candidate well is Pleasant Bayou #2 due to its extensive drawdown period.

Scope of Work

The neutron and acoustic log data from Pleasant Bayou #2 will be hand digitized and loaded into the Schlumberger Atlantis log-analysis workstation, where environmental corrections will be performed on the logs. These comprise the baseline for subsequent comparisons. Logs will be run on Pleasant Bayou #2 over an interval to encompass the shales adjacent to the producing interval. The logs to be run are compensated neutron (preferably with an epithermal measurement included), sonic (with waveforms recorded), and pulsed neutron. These are the most effective logs through casing, there are baseline runs made in 1979 to which these may be compared, and they also happen to be measurements which are relatively sensitive to changes in the water content of shales.

The data on the tapes from these new runs will be transferred to the workstation for environmental corrections and comparison to the baseline runs. It is probable that some normalization will be required to compensate for limitations in the environmental correction algorithms as well as the imperfect knowledge of the conditions downhole, especially the degree of cementation. We will average the repeat and main pass of the nuclear tools and insist on slow logging speeds on the nuclear tools in order to minimize statistical error.

The changes in water content indicated by the logs will be used in a model of shale dewatering. Analytical work has been done in this area, and this will be utilized to the extent possible (Riney, et al.). It may then be possible to determine if shale dewatering is a significant factor in the pressure maintenance of the reservoir. Conclusions will be limited by the lack of knowledge of reservoir extent and structure, but it may also be possible to eliminate this mechanism from consideration should the reservoir characteristics required to explain the data be unreasonable.

If core material is still available, experiments will be performed to determine the relationship between swelling and water content changes as a function of confining pressure. We have a number of years experience in this area, and have thus refined the techniques required to make these difficult measurements.

Project Management

Supervision of the project will be provided by Dr. Steven Morriss, including the on-site monitoring of the logging. The analysis will be carried out by Dr. Henry Dunlap and a part-time graduate student, with support from Dr. Morriss. A part-time undergraduate student will digitize the original logs.

References

T. D. Riney, S. K. Garg, and R. H. Wallace; "Effect of Shale Water Recharge on Brine and Gas Recovery from Geopressured Reservoirs"; Geopressured-Geothermal Energy: Proceedings of the Sixth U. S. Gulf Coast Geopressured-Geothermal Energy Conference, Pergamon Press, 1985.

M. I. Javalagi, S. L. Morriss, S.L., and M. E. Chenevert: "Time-Lapse Resistivity and Water-Content Changes in Shale", presented at the Society of Professional Well Log Analysts Thirty-Second Annual Logging Symposium, Midland, TX, June 1991.

BUDGET: DETECTION OF WATER INFLUX FROM ADJACENT SHALES USING WELL LOGS

1/1/92 - 12/31/92

		Person-Month	Total Costs
A.	Salaries and Wages		
	Salaries and wages paid from grant funds at The University of Texas at Austin conform to the rates approved by the Board of Regents for salaries paid from regular university funds.		
	Project Director, Steven L. Morriss	1.5	$ 8,160
	Project Director, Henry F. Dunlap	3.6	19,472
	Graduate Research Assistant	6.0	12,000
	Undergraduate Research Assistant	3.0	2,988
	Senior Administrative Associate	6.0	17,862
	Total		$ 60,482
B.	Staff Benefits		
	Fringe Benefits (26% of S&W)		15,725
	VSL (0.7% of staff S&W)		125
C.	Total Salaries and Wages plus Benefits		$ 76,332
D.	Materials & Supplies (run compensated Neutron, Sonic (with waveforms), and Pulsed Neutron Logs)		37,000
E.	Travel		1,331
	1 trip to well site/Houston, TX (1 person @ 2 days/trip)		
	Airfare	103	
	Per Diem (2 days @ $70/day)	140	
	1 trip to meeting/Idaho Falls, ID (1 person @ 2 days/trip)		
	Airfare	876	
	Per Diem (2 days @ $70/day)	140	
	Transportation (2 days @ $36/day)	72	
F.	Total Direct Costs		$114,663
G.	Indirect Costs (48% of Modified Total Direct Costs)		55,038
H.	Tuition and Fees		2,000
I.	Total Budget		$171,701

Selected Papers Resulting from this Research

NO. 92/0176

ANALYSIS OF BORON EFFECTS ON WIRELINE ESTIMATES OF POROSITY AND GAS SATURATION IN TIGHT GAS SANDS

(Abstract Only)

TOPICAL REPORT
November 1989 - December 1991

PREPARED BY

Henry F. Dunlap, Robert V. Everett and Marie C. Quirein

Department of Petroleum Engineering
The University of Texas at Austin
Austin Texas 78712

for

Gas Research Institute
GRI Contract Number: P9987-0275-S
Subcontract under CER/GRI No. 5089-211-1842
Larry Brand, GRI Project Manager

December 1991

ANALYSIS OF BORON EFFECTS ON WIRELINE ESTIMATES OF POROSITY AND GAS SATURATION IN TIGHT GAS SANDS

ABSTRACT

Boron in trace amounts causes both the compensated thermal neutron log and the thermal pulsed neutron log to overestimate porosity by as much as several porosity units. Boron can also cause large overestimations of water saturation when using the pulsed neutron log. Boron cannot be measured directly by any currently available logging tool. Corrections for boron must depend on elemental analysis of cores or on correlations of boron with log-derived variables such as Al, K or the gamma log. Studies of these correlations in 5 GRI wells plus an additional well reported in the Bulletin of AAPG (June 1990) showed that useful estimates of boron content can be obtained from such correlations. Also, the correlations seem to be valid over at least a mile in East Texas and perhaps as much as five miles in Wyoming. Correlations of epithermal versus thermal neutron logs look especially promising since they avoid the problems of core-to-log depth mismatch and sample size variation, core versus log. They account not only for boron but for other high capture cross section elements such as gadolinium, chlorine, etc. Pozzolan is often used as a cementing additive in amounts up to 50% when cementing oil wells. It contains a lot of boron. The GRI SFE #4 well was completed using a 50/50 pozzolan-cement mix. The average openhole thermal neutron porosity in the perforated interval of this well was 4 p.u. lower than the average casedhole value (10.7 p.u. versus 14.7 p.u.).

Boron in Geopressured-Geothermal Formations and in Casing Steels

H. F. Dunlap: Department of Petroleum Engineering, University of Texas, Austin
G. R. Coates: NUMAR Corporation, Malvern, Pennsylvania

Abstract: Data from five geopressured-geothermal wells and a number of hydropressured wells suggest that the average boron content of geopressured formations (sands and shales) may be about 25% less than the boron content of hydropressured wells. This difference, however, is less than the standard deviation of the boron content of sands or shales for either category of well. These data imply that the high pressures and temperatures encountered in geopressured formations have probably not had a major effect on boron diagenesis. The ratio of the average boron content in the shales to that in the sands is 3.3 for the geopressured formations; this ratio is 2.8 for the hydropressured formations. A study of boron in various grades of steel from a number of foreign and domestic sources indicates that boron content is normally low. We were concerned about this because boron is often added to high-strength steels intended for severe service. The data do suggest that boron content varies with steel type. The mean boron content of six K-55 steels was 2 ppm; the mean for four P-110 steels was 19 ppm.

INTRODUCTION

Previous reports (Dunlap and Coates, 1988, 1990) have shown boron to be a commonly encountered element in many Texas formations. Although boron affects the thermal-neutron log, making porosity estimates too high, no presently available logging tool can measure boron directly. Any correction for the boron effect must depend on elemental analyses of cores (almost never available) or on indirect methods based on correlations of boron with other elements or minerals that can be estimated from logs—for example, potassium from the gamma-spectral log or gadolinium from the geochemical log. This approach appears reasonable because previous studies have shown that boron increases with shale content of the rock, and both potassium and gadolinium are known to increase with shale content (Tittle and Glasscock, 1988). Boron correlations established in one or more key wells in an area might then be used to estimate boron content in nearby wells.

Boron content is probably affected to some degree by diagenesis. In this paper we compare the boron content of sands and shales in hot geopressured-geothermal formations with the boron content of cooler hydropressured formations.

Boron is sometimes used to strengthen steels. Because the thermal-neutron log is often run in cased wells, we have measured the boron content of various grades of steel casing, both foreign and domestic.

RESULTS

Rock Data

Table 1 gives the well name, location, and pressure and temperature data for the five geopressured wells we studied (Morton, 1981; Durrett, 1985; Garg and Riney, 1985).

Table 1: Data for geopressured wells examined for boron content.

Well name	Location	Perf depth (ft)	Top of geopres (ft)	Temp at perfs (°F)	Pressure at perfs (psi)	Water salinity (ppm)	Geologic age
Pleasant Bayou # 1	Brazoria Co., Texas	—[1]	8,500	301	11,050	121,000	Lower Frio
Pleasant Bayou #2	Brazoria Co., Texas	14,644–14,704	8,500	301	11,050	121,000	Lower Frio
L. R. Sweezy #1	Vermillion Parish, Louisiana	13,349–13,388, 13,395–13,406		237	11,410	100,000	Upper Frio
Gladys McCall #1	Cameron Parish, Louisiana	15,470–15,160		287	12,800	168,500	Lower Miocene
Great Western Oil & Gas OCS-G7661B-2	E. Cameron, Offshore, Louisiana	14,915–15,044	—[2]	256	12,179	150,000[3]	Pliocene

[1] This hole had to be junked. Pleasant Bayou #2 offset it about 200 yards.

[2] Top of geopressure at 11,050 ft. goes back to hydropressure from 12,720 to 13,400 ft. remains geopressured from 13,400 to TD at 15,524 ft.

[3] Produces dry gas, no water; estimated from nearby wells.

Table 2: Data previously obtained for hydropressured wells.

Wells	No. wells	No. boron analyses	Depth range (ft)
Texas Gulf Coast Frio[1]	9	27	6,885–12,180
West Texas, noncarbonate[2]	8	26	2,650–10,146

[1] See Dunlop and Coates (1988).
[2] See Dunlop and Coates (1990).

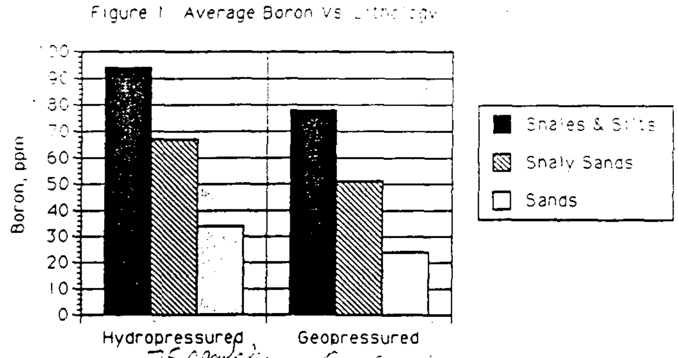

Figure 1: Average boron versus lithology.

Table 2 gives number of wells, etc., for the hydropressured well data, taken from our two previous reports (Dunlap and Coates, 1988, 1990). The geopressured data is from Frio, Lower Miocene, and Pliocene formations. The hydropressured data is from the Frio and several older formations. Table 3 summarizes the entire data set. (Details of boron content versus core depth for each of the five geopressured wells are available from the authors on request.) Means and standard deviations of the boron content are given separately for the shales and siltstones, shaly sands, and sands (these classifications were made from visual examination of the core samples). Geopressured and hydropressured wells are considered separately. Note that the difference in mean boron content between hydropressured and geopressured formations is always less than the standard deviation of any given mean (for shale, sand, or shaly sand). Thus, the lower mean boron content for all three classes of geopressured formations may not be significant. Figure 1 shows the average boron content for shales, sands, and shaly sands, both hydropressured and geopressured.

Steel Data

Table 4 shows the source, grade, and boron content of the 19 casing steels we studied. Several samples of grades P-110, N-80, J&K-55, and C-53 from both foreign and domestic sources were examined. Lone Star Steel, which supplied several of the samples, also gave us their measurement of the boron content for their samples. The only really bad mismatch between Lone Star's boron measurements and ours (made by the Bureau of Economic

Table 3: Average boron content and ratios as a function of lithology in geopressured and hydropressured formations.

		Shales		Shaly sands		Sands	
Well	Location	*N*	Boron content (ppm)	*N*	Boron content (ppm)	*N*	Boron content (ppm)
Geopressured formations							
Pleasant Bayou #1	Brazoria Co., Texas	18	75 (17)[1]	0	–	31	19 (15)
Pleasant Bayou #2	Brazoria Co., Texas	3	85 (2)	0	–	7	28 (7)
Gladys McCall #1	Cameron Parish, Louisiana	0	–	0	–	2	3 (4)
L. R. Sweezy #1	Vermillion Parish, Louisiana	10	96 (40)	0	–	4	40 (23)
Great Western Oil & Gas	Offshore, Louisiana	10	65 (18)	1	51	8	38 (8)
Total		41	78 (~25)	1	51	52	24 (~15)
Hydropressured formations							
Pleasant Bayou #1	Brazonia Co., Texas	1	72	0	–	1	12
Great Western Oil & Gas	Offshore, Louisiana	7	64 (8)	0	–	8	51 (14)
Frio Sands[2]	Texas Gulf Coast	11	106 (53)	5	74 (56)	11	21 (16)
Noncarbonate[3]	West Texas	26	97 (51)	3	54 (9)	2	43 (11)
Total		45	94 (~50)	8	67 (~30)	22	34(~12)

Ratios

$\text{B Shale}_{geo}/\text{B Shale}_{hydro} = 78/94 = 0.83$

$\text{B Sand}_{geo}/\text{B Sand}_{hydro} = 24/34 = 0.71$

$(\text{B Shale}/\text{B Sand})_{geo} = 78/24 = 3.3$

$(\text{B Shale}/\text{B Sand})_{hydro} = 94/34 = 2.8$

[1] Mean (s.d.).
[2] See Dunlop and Coates (1988).
[3] See Dunlop and Coates (1990).

Table 4: Boron content in casing steel.

Supplier	Sample description	Sample source	Boron content (ppm)	Lone Star boron value (ppm)
Hydril Company	U.S. Steel K-55	U.S.	<1	
	Pusan K-55	Korea	<1	
	Sumitonio K-55	Japan	5	
	North Star N-80	U.S. (Ohio)	13	
	N.K.K. N-80	Japan	8	
	National Pipe N-80	U.S.	2	
	Kawasaki K095T/P110	Japan	44	
	Tubular Corp. TCA-110 CP	U.S.	13	
	Nippon P-110	Japan	9	
	Tubular Corp. P-110	U.S.	9	
Lone Star Steel From different heats	K-55/076-9	U.S.	2	<1
	C-53/064-9	U.S.	69[1]	16
	C-53/064-9	U.S.	16	10
	C-53/064-9	U.S.	14	8
	C-53/069-9	U.S.	22	10
	K-55/036-9	U.S.	2	3
	K-55/036-9	U.S.	1	2
	J-55/164-9	U.S.	1	1
	C-53/064-9	U.S.	19	20

[1] Mean of two analyses, 71.4 ppm and 67.3 ppm.

Geology Mineral Studies Lab) was for a C-53 steel, where Lone Star reported 16 ppm, and our value was 69 ppm (mean value of two separate analyses of 71 and 67 ppm). We suspect that our sample was somehow contaminated, because 69 ppm is much higher than the value for any other steel we measured. Figure 2 shows a plot of the lowest and highest boron content for each of the four steel types. K-55 and N-80 steels have lower boron values than either C-53 or P-110 steels.

CONCLUSIONS

Boron is consistently lower in geopressured shales, sands, and shaly sands than in their hydropressured equivalents. However, this difference is less than the standard deviation of boron for any single lithology, whether hydropressured or geopressured. We conclude that the high temperatures and pressures probably have not had much effect on the boron diagenesis in these samples.

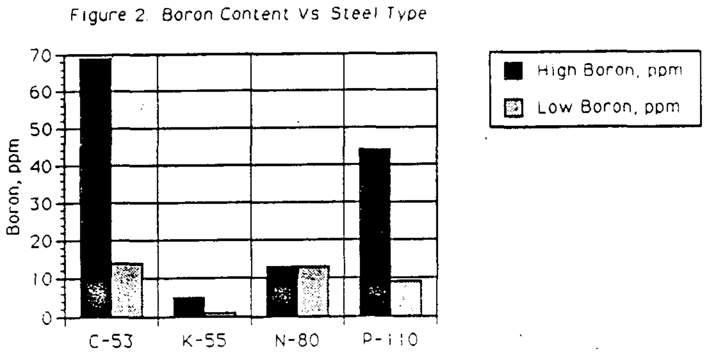

Figure 2: Boron content versus steel type.

Boron content of casing steels is modest, probably in the 1–40 ppm range, but does appear to vary with steel grade. The average boron content of J&K-55 steels is 2 ppm; of N-80 steels, 8 ppm; of C-53 steels, 19 ppm; and of P-110 steels, 28 ppm. This added boron should create only a minor problem as long as similar casing steel grades are used across similar reservoirs in a field. If casing steels with widely different boron contents are used, then a correction may be needed when estimating porosity from thermal neutron logs in cased holes.

ACKNOWLEDGEMENTS

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THE EVALUATION OF A GEOPRESSURED-GEOTHERMAL PROSPECT

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Presented at Industrial Consortium for Utilization of Geopressured-Geothermal Resource

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Balcones Research Center

THE EVALUATION OF A GEOPRESSURED-GEOTHERMAL PROSPECT

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Abstract

The technology used in evaluating a hot, high pressure water reservoir and its associated solution gas is that of the oil industry, developed over many decades. The first step in evaluation is to do economic modelling, using discounted cash flow (present worth) methods, which take into account the time value of money. These models also require the matching of the production capacity of the resource (hot water and its associated methane), with the requirements of the proposed project (alligator farming, greenhouses, power generation, etc.). Risk can be estimated by using Monte Carlo techniques - running the model many times, changing values for each run for those parameters which are uncertain. Unless the model shows a positive present worth for reasonable input parameters, you should not undertake it. Play the game on paper before you play it with real money.

In order to carry out the economic modelling, we need initial estimates of reservoir size, production rate as a function of time, water temperature, pressure, salinity, and amount of solution gas (methane) available. These estimates are obtained from knowledge of geology in the area, geophysics (seismic data), well logging information, core analyses, and various reservoir engineering calculations used routinely by petroleum engineers.

Considerable information is already available in the proceedings of six symposia on geopressured-geothermal energy which have been published [10-15]. These include geological studies, and the results of several short term (few weeks), and long term (1 to 4.5 years) tests of several geothermal prospects. If the location and characteristics of any of these is suitable, it should be considered carefully for commercial application. We already know a lot about these reservoirs.

Specific problems which require particular attention because of the high flow rates involved include: (1) possible sand flow from the producing reservoir; (2) possible scale formation; and (3) potential environmental problems - not experienced thus far - due to the large volumes of water withdrawn (possible subsidence) and the need to reinject the spent brine into a shallow disposal well (possible fresh water contamination). Our experience to date indicates that these problems can be handled by use of existing technology.

One problem which is still outstanding is the drive mechanism in geopressured reservoirs. There is some evidence that either (a) shale dewatering, or (b) leaking fault barriers, or both, are helping maintain the pressure at the Gladys McCall reservoir. Pressure decline in this reservoir is much smaller than expected for the volume of water

produced. This is one of the better types of uncertainties to have, since it leads to a larger reservoir than would be predicted from conventional geological, geophysical, logging, and core data inputs.

In summary, we feel that enough is now known about the geopressured-geothermal resource to permit economic application at reasonable risk. The energy base is huge for both hot water and for methane. Since direct heat use (aquaculture, greenhouses, food processing) occurs at several temperature levels, multiple use of the hot brine for several processes requiring successively lower temperatures would seem ideal. Direct sale of the associated gas to a pipeline should be simple.

Introduction

Geopressured-geothermal reservoirs contain energy in three forms: hot water; dissolved gas (mostly methane); and high pressure water. Much effort has gone into study of ways to use all three forms of this energy effectively. In today's economy, and for the near term future, the hot water used as a direct source of heat appears to be the most attractive, supplemented by gas sales, and use of any available hydraulic horsepower that fits the particular project requirements. The reason for this is three fold: (1) direct heat applications typically have considerably lower capital requirements than capital needed for electric power generation; (2) the dissolved gas produced would have to sell for considerably more than today's price of \$1.50 to \$2.00/mcf to be profitable for gas production alone; and (3) the hydraulic horsepower is smaller than the other components, and may be partly used up by the need to inject the spent brine into a disposal well.

To keep things in perspective, remember that if gas is worth \$1.50/mcf (equivalent to \$1.50/10^6 BTU) and if the produced water contains 30 SCF/bbl of dissolved gas, each barrel of water is worth 4.5¢ for its gas content. If the produced hot water gives up heat by cooling from 300°F to 100°F this amounts to 67,200 BTU/bbl, worth about 10¢/bbl, @ \$1.50/10^6 BTU. Thus, a geopressured-geothermal well producing a conservative 10^4 B/D of water with the above characteristics might generate a cash flow of \$1,000/D (from direct heat use) plus \$450/D (from gas sales) for a total gross income of \$1,450/D. This neglects any income from hydraulic horsepower, which would be relatively small.

Although there may be unusual circumstances (remote locations, for example) which may make power generation and/or gas sales economically attractive without direct heat use, I believe these will be the exception. In what follows I assume that <u>all</u> forms of the available energy are used that make economic sense, with emphasis on direct heat use. We decide which projects make economic sense by use of economic modelling, described in the next section.

Economic Modelling

In economic modelling, we study the proposed application by estimating the costs and income expected for the project, together with the time schedule over which the costs occur and the income is received. A "present worth" for the project is calculated, using an interest rate competitive with other investment opportunities. The calculation appreciates past costs and income at the chosen rate, and discounts future costs and income at this same rate when calculating the present worth of the project.

If the present worth is positive, you will make money; if negative, you will lose money. The "project rate of return" is the interest rate which makes the present worth zero. If the project rate of return is higher than the commercially available interest rates, the project is attractive, if lower, you would be better off investing in something else.

There are many variations of economic modelling, but the above simplified description of the process points out the essential features. All require estimates of capital investment, operating costs, and income generated, together with the times at which these occur. Since generally these costs and incomes and time schedules are estimates and are not precisely known, the model is run many times, using various reasonable estimates for the uncertain values. This allows a distribution of present worths to be obtained. This is called Monte Carlo modelling, after the famous gambling casino. It allows the potential investor to assess the risks associated with the investment[1,2,3,4,5].

The better we understand the economics and heat requirements of the proposed applications (alligator or fish farming, greenhouses, food drying, enhanced recovery of viscous oil, and the like), and the production economics and hot water availability from the geopressured reservoir, the more reliable our model results will be. We assume that the entrepreneur knows the economics and heat requirements for the proposed application. We know something about estimating the reservoir size, water production rate with time, water temperature, pressure, salinity, and solution gas content. These estimates are based on methods used for many years by petroleum engineers, geologists, geophysicists and log analysts in the oil and gas industry. They are faced with essentially the same problem when deciding whether or not to develop a new oil or gas field. The next section discusses how these reservoir estimates are obtained.

Estimating Reservoir Inputs to Economic Model

Initial estimates of reservoir size come from geological and geophysical (seismic) work which seek to define aerial extent, thickness, and porosity of the reservoir. These will define the total water content. Input data also comes from (1) logs and production test data from one or more prospect wells, (2) well logs from other wells in the area (thickness, porosity and temperature estimates; possible definition of limiting faults), (3) detailed seismic work (fault, unconformity and sand pinchout locations) and (4) core analysis (porosity, permeability). Each reservoir is different, of course, and the input data will always be limited. A distribution of probable values for porosity, permeability, reservoir area, etc. can be developed from the available data, and these values are used in the Monte Carlo modelling of the economics. The best data is actual production from the reservoir of interest over a substantial time period, followed by a shut-in period to measure pressure recovery. This is seldom available early in the life of a project, but we do have these data for the DOE Gladys McCall #1 well, and the Pleasant Bayou #2 Well, which we will discuss in more detail later.

An example of the application of modern log analysis as applied to this problem is shown for the DOE Hulin #1 well. This deep (20,000+ feet) hot (350°F) well contains a relatively clean sand body from about 20,220 ft. to 20,690 ft. which had not been previously tested. Open hole resistivity logs run by Superior Oil Company in this well in the late 70's indicated small free gas saturations in this sand (20-30%), probably at or below the gas saturation which would permit gas to flow. We wanted to confirm this indication if possible, and recommended the running of the dual burst (TDT-P) pulsed neutron log, which would provide a water saturation estimate in the cased well, independent of resistivity logs, which cannot be run in cased wells. The pulsed neutron tool was only able to log the upper 30 ft. of the sand before a tool failure occurred. However, analysis of this upper section confirmed the previous indication of low (close to irreducible) gas saturation shown by the open hole logs.

A more sophisticated, computer-based analysis of the logs was then carried out, using our "Elite" workstation and "Elan" software[6]. These let us analyze for shale, bound water, sand, gas, and bulk water content using all the logs available, and let us test for consistency by comparing each log with a reconstructed log calculated from the remainder of the logs run. A "confidence level" is then calculated based on how well the observed logs match the calculated (reconstructed) logs. If any log shows a poor match between the observed and calculated versions, it can be dropped from the data set and the operation repeated to obtain a higher confidence level.

Cases were chosen to represent the expected range of variation for m (cementation exponent); n (saturation exponent); and Σ_{matrix} (neutron capture cross section for matrix): m = 1.8 and 2.0; n = 1.8 and 2.0; Σ_{matrix} = 5.0 and 4.25 capture units. Fixed values of other parameters used in the analysis were Σ_{gas} = 10 c.u. (methane); Σ_{shale} = 50 c.u.; Σ_{water} = 95 c.u.; ρ_{gas} = .285 gm/cc; ρ_{matrix} = 2.65 gm/cc; Δt_{matrix} = 51.5 µs/ft.

Results for the best case (highest confidence level) are shown in Figures 1 and 2. A few comments on the results follow. Gas was indicated at about irreducible saturation for all cases. The confidence level is rather low when all well logs (open and cased hole) are used, due mainly to the poor match between the observed and reconstructed neutron porosity log. (See Figure 1.) When the Elan analysis is repeated omitting the neutron porosity log, note the marked increase in confidence which is obtained. See bottom of Figure 2, Model IV.

An Elan analysis was next run over the entire 20,200 - 20,700 ft. interval using only the open hole logs. (See Figure 3.) We see that a low gas saturation is shown throughout the sand, but the confidence level is low. When the analysis is repeated omitting various logs, the confidence is greatest when the neutron log is omitted, (Model IV), and we see we still have a low gas saturation throughout the sand (Figure 4).

We repeated the analysis assuming low density and high density condensates for the hydrocarbons instead of methane. We still calculate low saturations of hydrocarbons throughout this sand for these assumptions.

The effect of these low gas or condensate saturations will be observed only after the reservoir pressure begins to fall substantially. If there were no free gas in the reservoir, gas coming out of solution in the reservoir initially would be trapped in the pore space. Gas cannot flow until the saturation increases enough to reach irreducible. Gas coming out of solution up to this stage could not flow. If gas saturation approximately equal to irreducible gas is already in place, gas coming out of solution in the reservoir can begin to flow immediately. However, most of the pressure drop (and gas evolution) will initially occur in the tubing between the formation and the surface. Substantial pressure drop in the reservoir will not occur until many months after production starts. When the reservoir pressure does drop, the original, irreducible free gas in place will expand due to the reduced formation pressure and begin to contribute to gas flow, along with the gas coming out of solution from the water. The effect of this initial residual gas saturation will therefore not be substantial until substantial water production has occurred.

Using data described above to estimate reservoir volume, porosity, permeability, etc., the reservoir engineer can calculate a range of values for the flow rate from the reservoir that will be possible as a function of time. This is the input that is needed for running the economic model. References 7, 8 and 9 give examples of how such calculations are made.

Information Sources on Geopressured-Geothermal Reservoirs and Potential Applications

The Department of Energy has sponsored six symposia on this subject over the last 15 years which give a wealth of information[10, 11, 12, 13, 14, 15]. Much of the material is dated in that the price of gas and oil was much higher than it is today, and the discussion of applications is much more heavily slanted toward electric power production and gas sales than today's economy would suggest. However, the geology, geophysics and reservoir information are all valid. Very recently (1990) DOE sponsored a symposium on industrial applications[16]. The proceedings give valuable recent perspectives. The Geo-Heat Center of the Oregon Institute of Technology has recently published a very useful, 400 page guidebook for direct use of geothermal heat[17]. The DOE has also published (1988) a very useful "Geothermal Innovative Technologies Catalog," which briefly describes and gives sources for databases, hardware, and computer models, of interest to geothermal developers[18]. I urge anyone interested in this field to become familiar with all of these references.

Interested developers should seriously consider using a reservoir that we already know something about, such as Gladys McCall, Hulin, or Pleasant Bayou. We know a lot (but not of course, everything) about them. Table 1 summarizes our information on these reservoirs. Obtaining equivalent information on an unknown reservoir would cost millions of dollars.

Potential Problems

(1) The high water flow rates (many thousand barrels/day) may lead to sand production if the reservoir rock is relatively unconsolidated. This can usually be handled by (a) cutting back the production rate, and/or installing slotted liners or screens plus gravel packs. If the sand production is not controlled it could lead to erosion of subsurface and surface equipment, sanding up in the well bore, or even collapse of the casing. This problem is best understood as imposing a possible upper limit on water production rate, which may (or may not) affect the economics for the particular application planned. (2) Scaling problems (deposition of calcium carbonate cement) in the production string and surface equipment have been encountered on some of the wells. DOE sponsored research on this problem by Professor M. B. Tomson and his associates at Rice University proved successful in stopping what had been serious scaling at both the Pleasant Bayou and Gladys McCall wells[19,20]. We believe the method will be widely applicable. (3) Environmental problems associated with the large volume of water which is drawn from the producing reservoir and reinjected into the disposal well(s) have not been encountered thus far at either Gladys McCall or Pleasant Bayou, where we have several years operating

history. We believe that all of the above problems can be handled by current, already developed technology.

A problem we are less certain about is the drive mechanism in a geopressured reservoir. At the Gladys McCall well, about 20,000 bbl/D of hot, gassy water was produced over a four year period (27 MM bbls total production) with relatively small drop in the bottom hole pressure. The well was shut in on October 1987 and the bottom hole pressure is still increasing. This suggests that either (1) shale dewatering[21], or (2) leakage across fault "seals," or (3) reservoir rock compaction, or all three are occurring to recharge the reservoir. Shale dewatering and reservoir rock compaction[22,23] are not generally considered important in conventional oil industry reservoir engineering, but relatively few commercial oil and gas reservoirs are geopressured. Leaking faults often do occur, even in hydropressured oil and gas reservoirs. We are carrying out long-term creep tests of reservoir rock samples[22,23]. Creep and some porosity reduction occurs, but we do not yet know enough about this to use rock creep in our reservoir models. At the present state of our knowledge, all we can say is that reservoir size estimates for geopressured reservoirs based on sealing fault boundaries, elastic rock behavior, and zero shale dewatering may be conservative.

Advantages of Multiple Use of Hot Brine

Most direct use processes have a rather narrow temperature range for optimum effectiveness. This makes a cascaded series of operations, each calling for heat input at successively lower temperatures, very attractive. Anderson & Lund[24] show an array of processes with varying temperature requirements, ranging from 50 to 350°F (see Figure 5). A series of operations, moving from higher to lower temperatures (right to left in this Figure 5), could be selected so as to optimize the use of the heat from the geothermal well. Such a complex of operations should have a much higher present worth than any single operation, and would use the available heat at maximum efficiency. A Russian operation organized in this way is described in reference 25.

Conclusions

Careful economic modelling plus state-of-the art technology developed over many years by the oil industry should permit economic application of the geopressured-geothermal resource for direct heat use and gas sales. Multiple use of the hot brine at several temperature levels at a single installation would be desirable for optimum economics, and efficient use of the available heat. Sale of the associated gas to a pipeline, plus supply of some of the hydraulic horsepower which might be needed in the direct heat applications should be possible.

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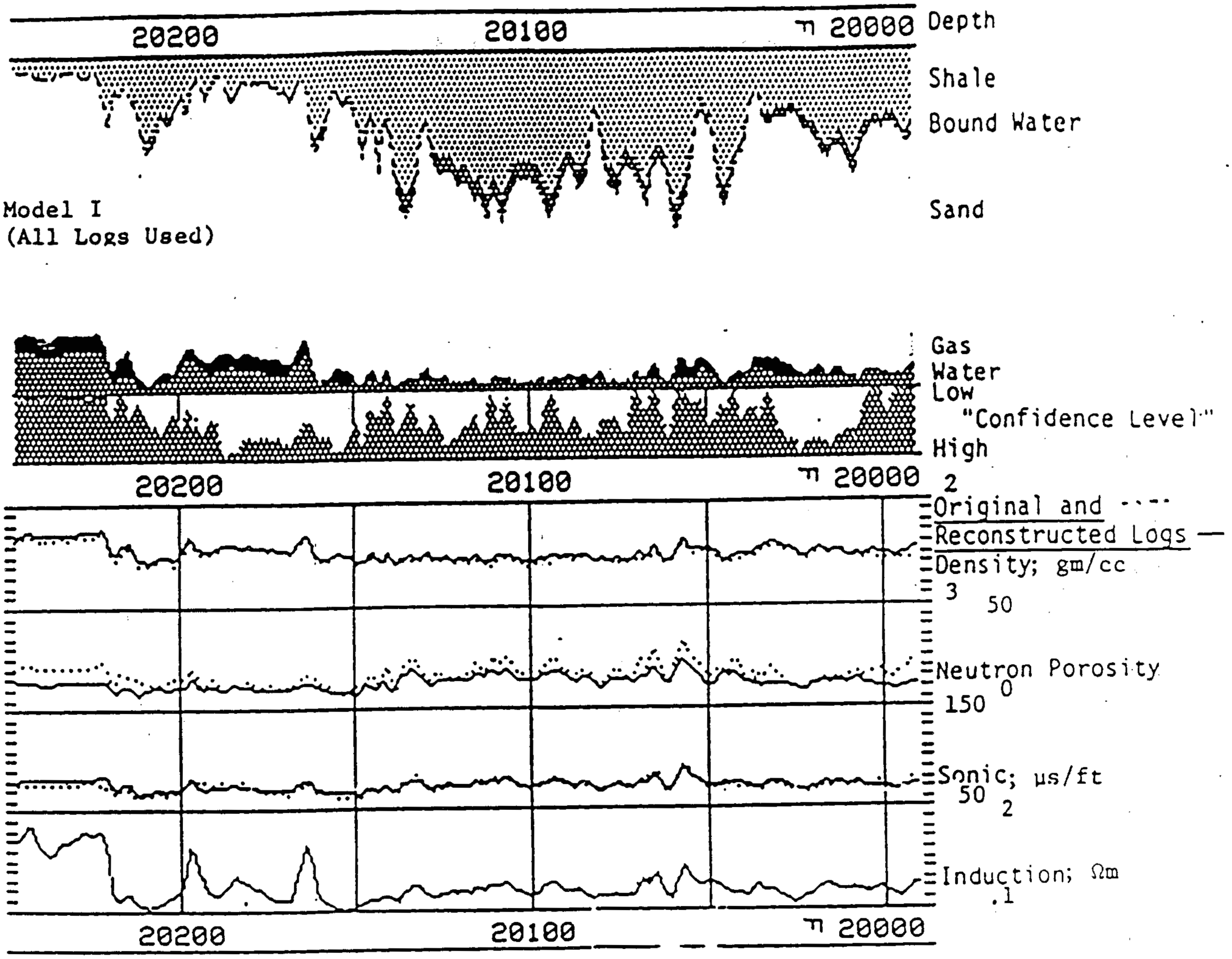
TABLE 1
WELLS AND RESERVOIR PROPERTIES FOR THREE DOE WELLS

Item	Gladys McCall #1 Cameron Parish, LA	Pleasant Bayou #2 Brazoria County, TX	Hulin #1 Vermillion Parish, LA
Depth (ft)	15,160-470	14,644-704	20,200-700
Max. Flow Rate B/D	40,000	25,000	15,000
Bottom Hole Pressure, psi	12,784	11,168	18,500
Flowing Wellhead Pressure, psi	2,000	3,000	3,500
Formation Temperature °F	298	302	360
Flowing Wellhead Temperature °F	268	292	330
Gas/Water Ratio, SCF/B	27	24	34
% Methane in Gas	85	85	93
Estimated Reservoir Size bbls x 10^9	4	8	14
Water Salinity mg/L	168,500	127,000	195,000
Total Water Produced, bbls	27 x 10^6	15 x 10^6	Limited
Comments	Well flowed from 10/83-10/87 at rates of 10,000 to 30,000 B/D. No problems with injection well. Some initial problem with scaling-controlled by injecting inhibitor.	Well flowed since 6/88 at 18,000 to 20,000 B/D; sand production may occur at rates > 22,000 B/D. Initial scaling problems controlled by injecting inhibitor.	Only short-term tests carried out thus far. Flow limited by tubing size; only part of sand is perforated. Tests through larger tubing are planned in 91.



Parameters Used:

Σ_m = 5.0 c.u.

Σ_H = 10.0 c.u. (methane)

m = 2.0

n = 2.0

Σ_{shale} = 50 c.u.

Σ_{water} = 95 c.u.

ρ_{ma} = 2.65 gm/cc

ρ_{gas} = .285 gm/cc

Δt_{ma} = 51.5 μs/ft

Figure 1: Elan Analysis, DOE Hulin #1 Well

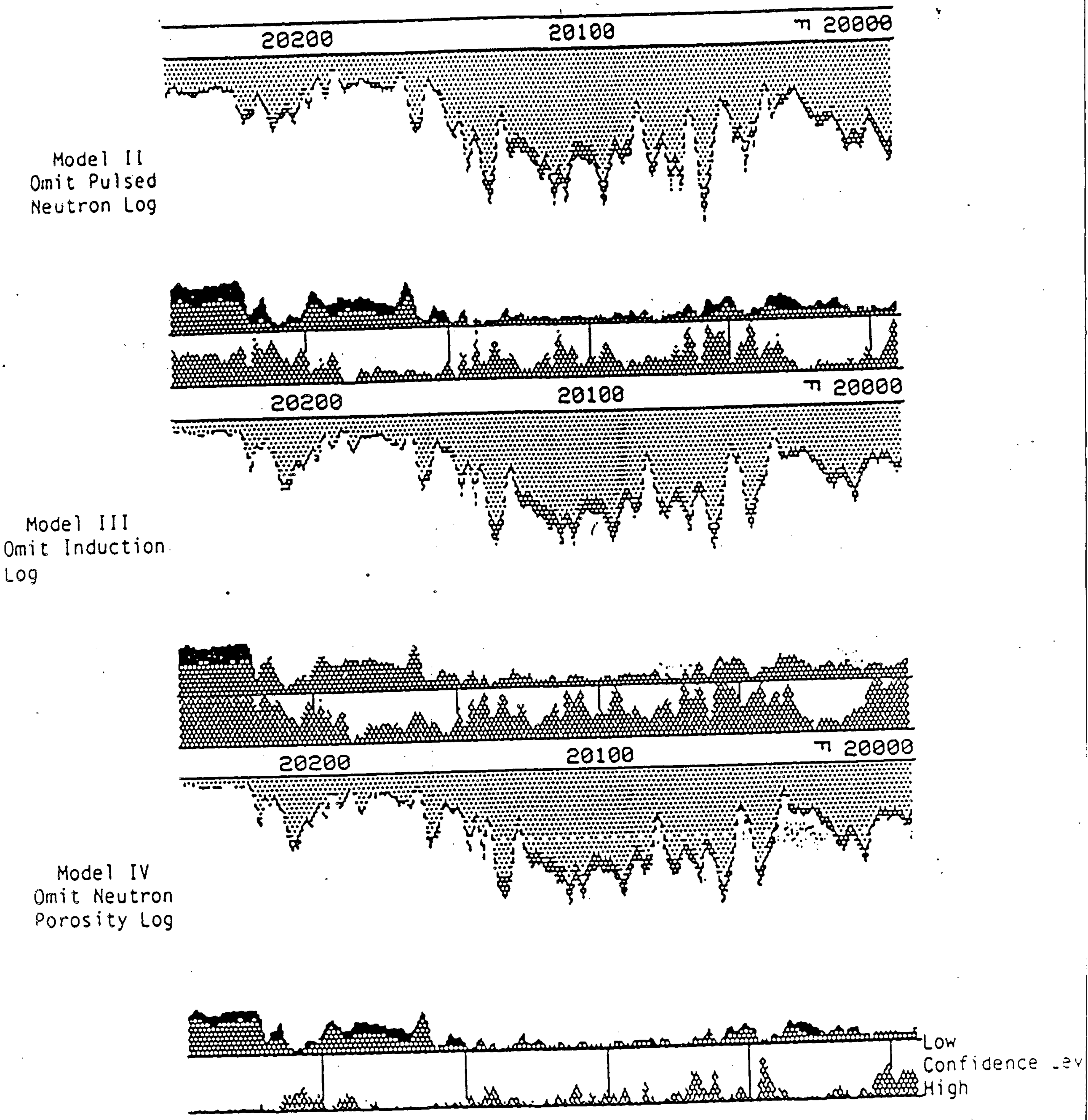
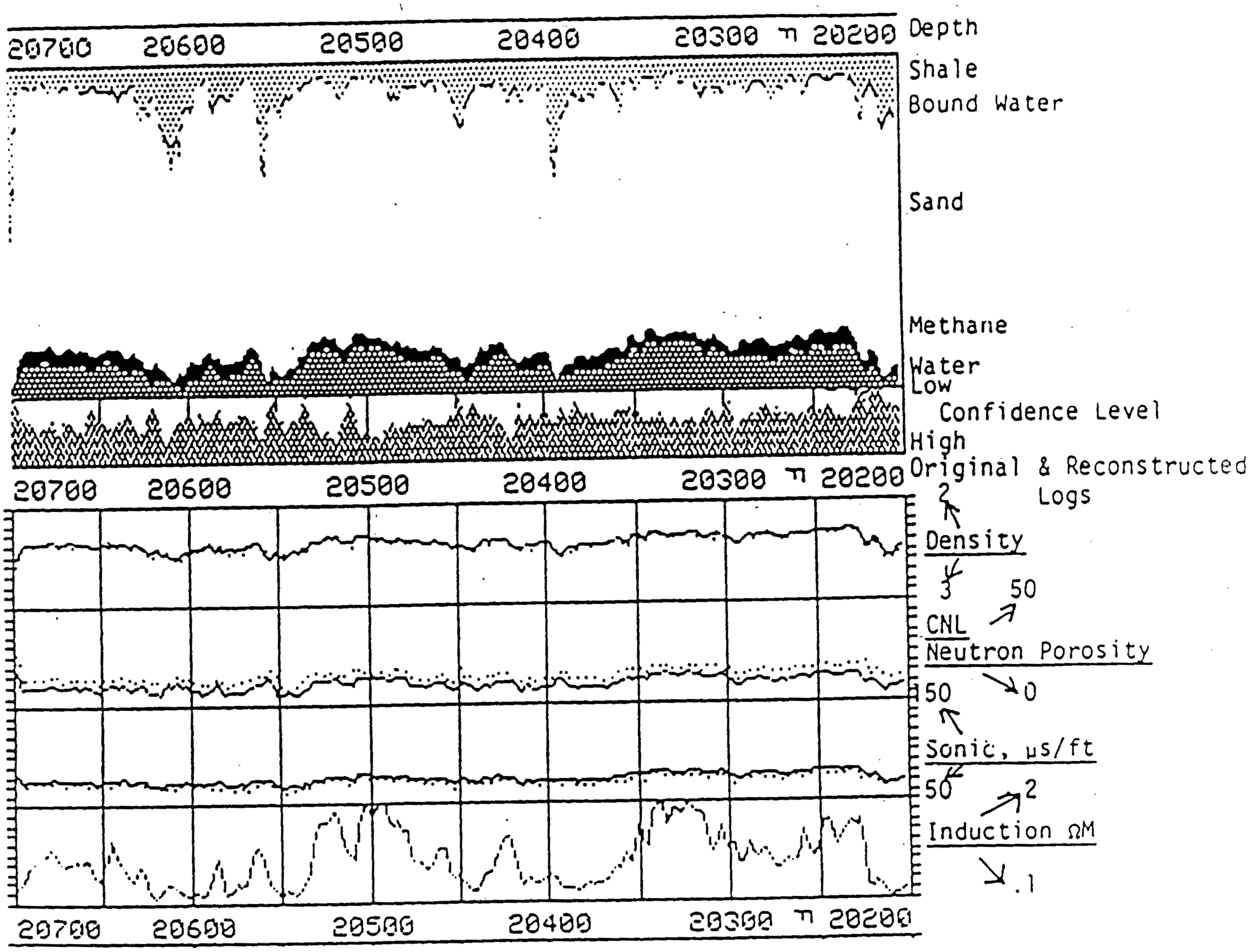


Figure 2: Elan Analysis, DOE Hulin #1 Well
Case I (Σ_m = 5.0 c.u.; m = 2.0, n = 2.0)



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ρ_{ma} = 2.65 gm/cc

ρ_{gas} = .285 gm/cc

Δt_{ma} = 51.5 μs/ft

Figure 3: Elan Analysis, DOE Hulin #1 Well (Methane)
Model I - All Open Hole Logs Used

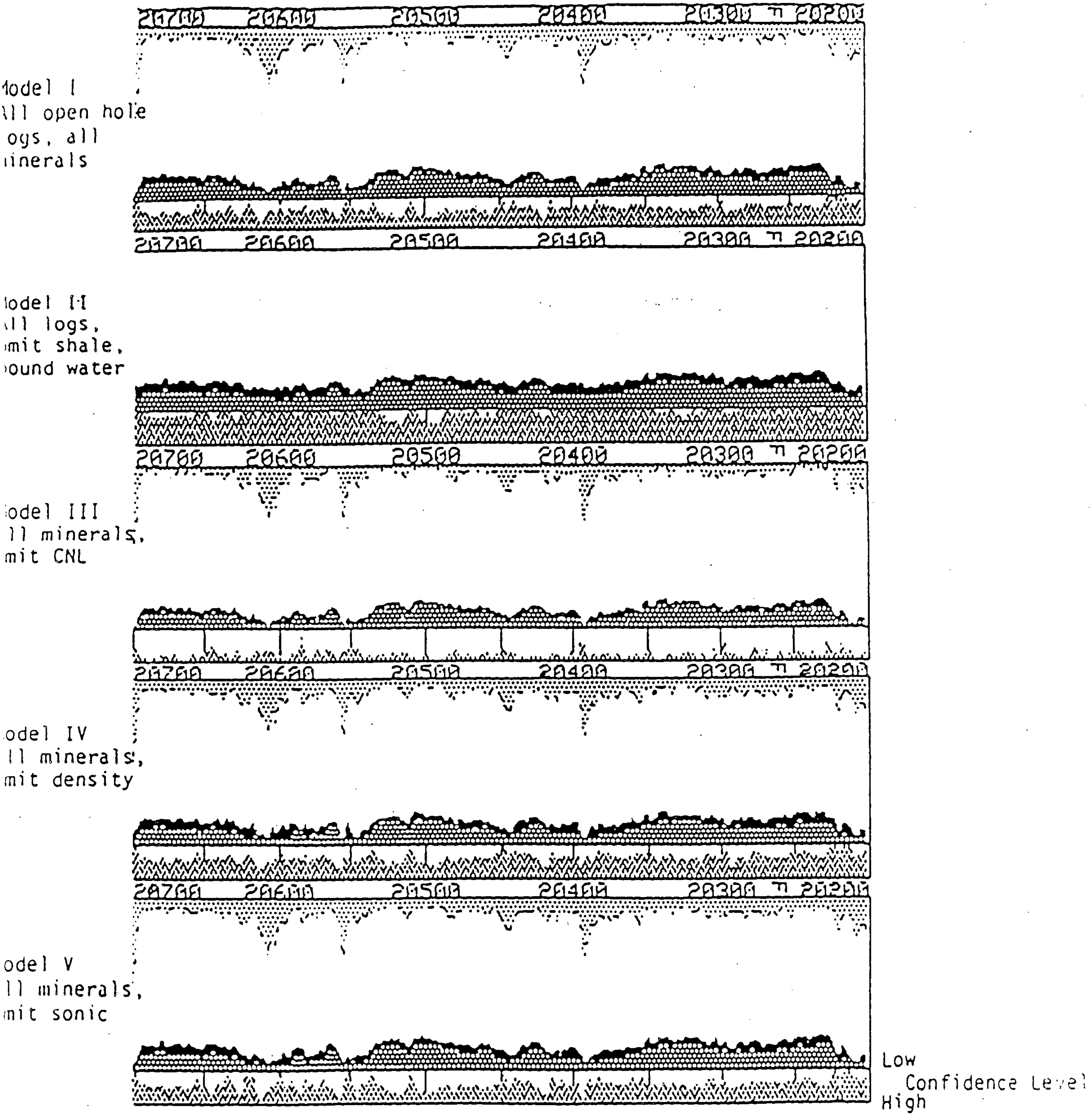


Figure 4: Elan Analysis, DOE Hulin #1 Well (Methane) Change in confidence levels when delete various logs or mineral constituents from model.

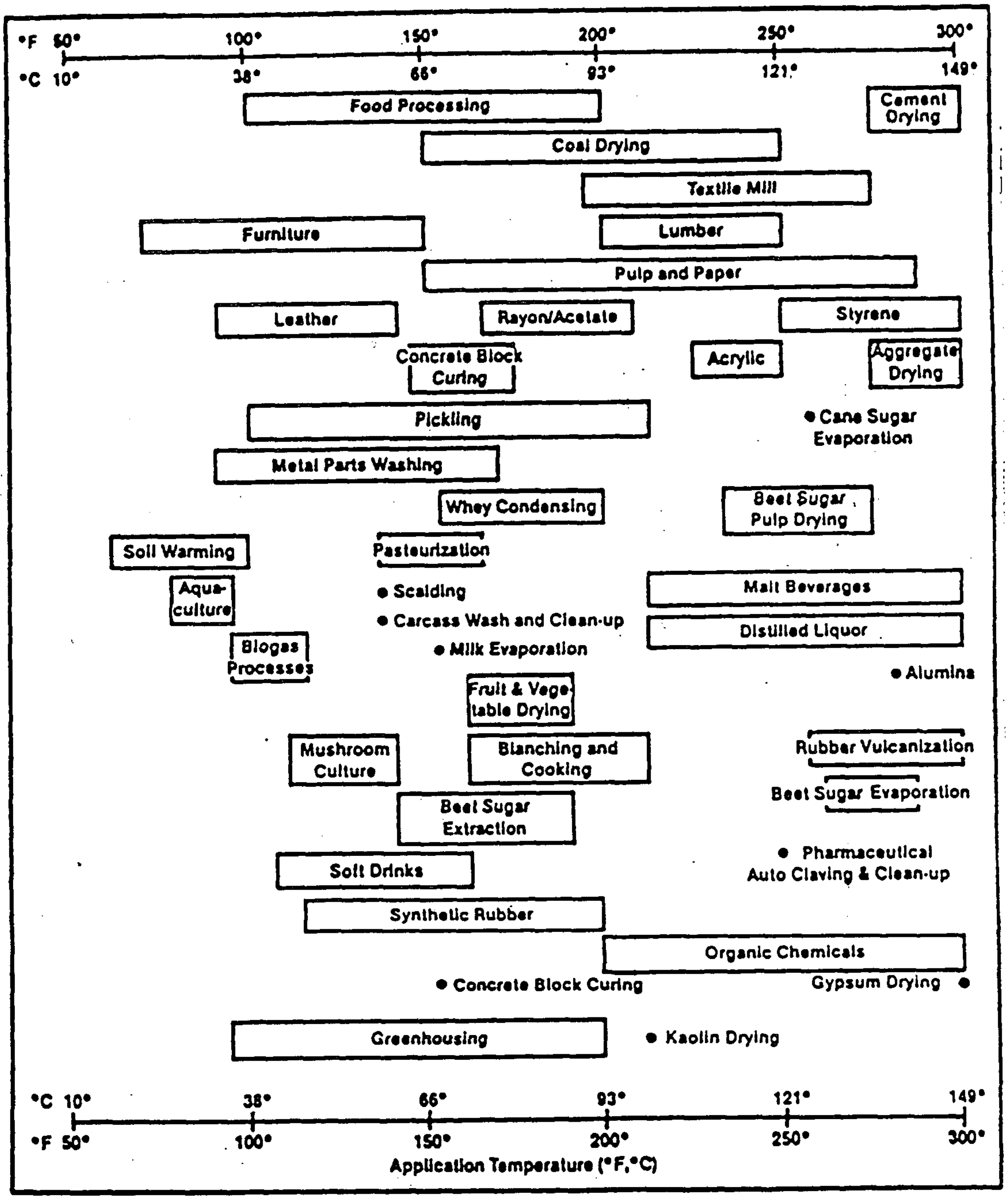


Figure 5: Application temperature range for selected industrial and agricultural applications (Anderson & Lund, 1979).

VALUE OF PRODUCED WATER

Assume water at well head is @ 300 F, with 30 SCF/B methane, selling for $1.50/MCF, and that process heat is worth $1.50/MMBTU.

Then:

Methane in one barrel of water is worth: $.045

Heat extracted from one barrel of water in going from 300°F to 100°F is worth: $.10

Total value of one barrel of water: $.145

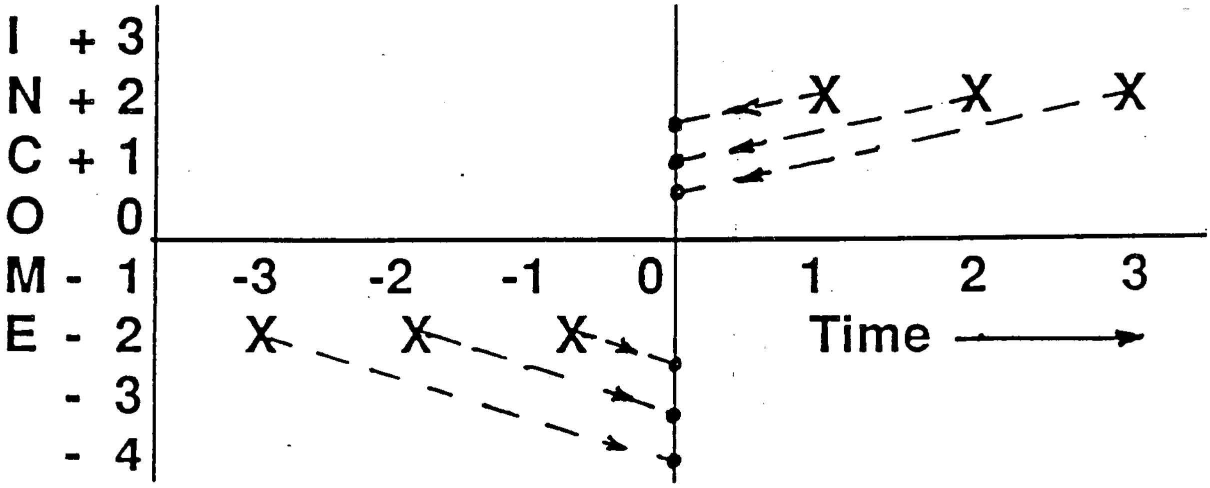
If well produces 10^4 B/D (conservative), gross cash flow would be: $1450.00/D

This must cover investment, operating costs, abandonment costs, and profit.

ECONOMIC MODELLING

(a) Takes into account time value of money.

(b) Can evaluate risk by running model many times, varying input assumptions (Monte Carlo method).



Sum discounted values of cash flow (+&-) to get Present Worth.

RESERVOIR INPUTS TO ECONOMIC MODELS

WE NEED: Estimates of porosity, permeability, thickness, area, temperature, and pressure.

1. Make first guess from previous drilling and seismic work in area.

2. Make detailed analysis of logs, cores, and production data in area to improve estimates.

3. Make distribution functions showing range of values expected for each variable.

4. Multiple runs of the model using values selected from these distribution functions will show the range of production capabilities expected for the reservoir.

INFORMATION SOURCES

1. DOE Symposia Proceedings (Six), plus Symposium on Applications, 1990.

2. "Geothermal Direct Use Engineering and Design Guidebook," Oregon Institute of Technology, Geo-Heat Center, Klamath Falls, Oregon 97601, 1989.

3. "Direct Utilization of Geothermal Energy: A Technical Handbook," Anderson and Lund, Geothermal Resources Council, PO Box 1350, Davis, California 95617; 1979.

4. U.N. Geothermal Steam Symposia.

5. Idaho National Engineering Lab., Idaho Falls, Idaho 83415, Dr. Jane Negus-de Wys.

POTENTIAL PROBLEMS

1. SAND PRODUCTION. A problem at Pleasant Bayou #2 at rates >22,000 B/D. No sand production at rates <20,000 B/D.

2. SCALING. An early problem at Gladys McCall and Pleasant Bayou wells, solved by "pill injection", developed by Prof. Tomson, Rice University.

3. ENVIRONMENTAL PROBLEMS (due to large volumes of water produced and reinjected). None encountered thus far at either Gladys McCall or Pleasant Bayou.

4. ESTIMATES OF RESERVOIR SIZE: Estimates tend to be too small, probably due to shale dewatering as pressure declines, or leaks across fault "seals," or both.

TEMPERATURE RANGE FOR SELECTED APPLICATIONS

1. 200°F--300°F. Lumber curing, sugar processing, paper production, organic chemical production, beer* and whiskey* production.

2. 100°F--200°F. Food processing*, mushroom culture*, soft drink production, concrete block curing, synthetic rubber production.

3. <100°F. Soil warming, aquaculture*, greenhouses*.

My own process choices are shown starred*, providing a drink, with chips, before a blackened red fish dinner with avocado salad.

CONCLUSIONS

1. Careful economic modelling plus use of state-of-the-art technology should permit profitable use of the geopressured-geothermal resource for direct heat use and gas sales.

2. Multiple uses of the hot brine at several temperature levels are desirable for efficient use of heat and optimum economics.

3. Sale of the associated gas to a pipeline, plus supply of some hydraulic horsepower in the operations should be possible.

Geothermal Resources Council TRANSACTIONS, Vol. 14, Part I, August 1990

WELL LOGGING RESEARCH
FOR THE DEPARTMENT OF ENERGY GEOPRESSURED-GEOTHERMAL PROJECT

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ABSTRACT

Our logging research this past year has concentrated on two areas of interest: the effect of boron in reservoir rocks, and analysis of logs of the #1 Hulin Well, South Louisiana.

The effect of trace amounts (10-100 ppm) of boron in the reservoir rock or in near well bore completion materials can be significant, since porosity estimates from various neutron logs will be too high if boron is present. Our studies have shown that boron is present in amounts to give concern in several formations and oil field cement formulations. The effect may be severe in some geothermal reservoirs.

State-of-the-art computer analysis of well logs in the deep, hot Hulin well in South Louisiana indicates that residual gas saturation occurs throughout a sand which is several hundred feet thick; this is unexpected unless the accumulation is geologically recent. Effect of diffusion of gas on produced gas/water ratio will be discussed.

BORON - INTRODUCTION

Occurrence of trace amounts of any of several elements with high thermal neutron capture cross section can lead to errors in interpretation of several commonly used well logs. These include the thermal neutron log, the pulsed neutron log, and elemental analysis logs, based on the measurement of the energy spectrum of gamma rays of capture of thermal neutrons. Boron emits no gamma rays of capture, and when present in the formation rock or other near well bore materials (drilling mud, cement, casing) it can cause errors in porosity and formation water salinity estimates. A recent paper reports on boron in the Frio of the Texas Gulf Coast, and on boron in mud components[1]. A second study (in press) shows that boron occurs in many West Texas formations, and in some oil well cements and cement additives.

The effect of boron on the log depends on details of the tool design, but in general boron causes overestimation of porosity and water salinity, and in the case of the pulsed neutron log, overestimation of water saturation.

The Boron Effect

The effect of thermal neutron absorbers, and boron specifically, can be illustrated in several ways. For example, in Figure 1 we show calculated values of the concentrations of boron, cadmium, and gadolinium in the rock matrix needed to equal the thermal neutron absorber characteristics of oil and brine at "irreducible water saturation," which fills the rock pore space. We see that in a 30% porosity zone (sand), 100 ppm boron in the rock gives a thermal neutron absorption about equal to that due to the hydrogen and chlorine in the fluids in the rock pore space. Hydrogen and chlorine are assumed to cause <u>all</u> the thermal neutron absorption in conventional neutron log interpretation. For a 10% porosity zone (limestone), as little as 25 ppm boron in the rock will give the same result. Many geothermal reservoirs produce from fractured metamorphic formations with very low porosities. Even small amounts of boron, 10-20 ppm, would lead to significant overestimation of porosity from the thermal neutron log.

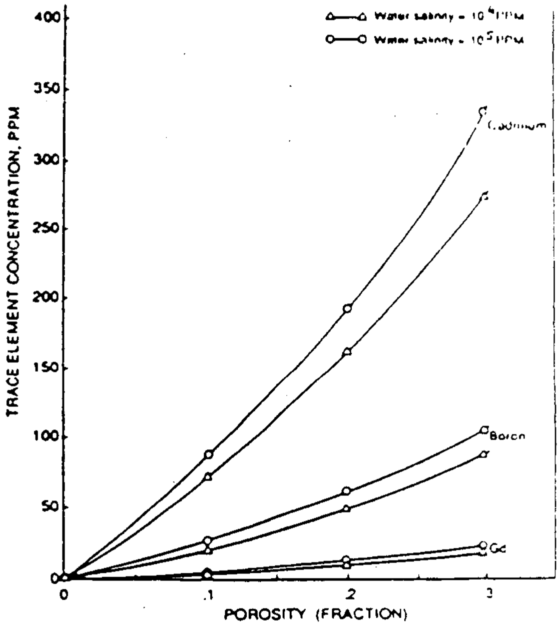

Figure 1: Trace Element in Rock: Concentration Needed to Equal Neutron Captures by Hydrogen and Chlorine. Water Saturation = .2; H in oil = H in water.

An illustration of probable thermal neutron absorber effects is shown in Figure 2, which is a comparison of a thermal neutron log apparent porosity with an epithermal neutron log apparent porosity. The epithermal log is not affected by boron or other high capture cross section elements, since it measures the neutrons in the epithermal energy range, where these high capture cross sections are not involved. The thermal log porosity is appreciably higher than the epithermal log porosity in the intervals from 9,705 top 9,782 ft. and from 9,650 to 9,675 ft. The difference is sufficient to wipe out the $Ø_D$ - $Ø_N$ reversal commonly used as a gas indicator, at depths of 9,710-9,716 and 9,722-9,728 ft.

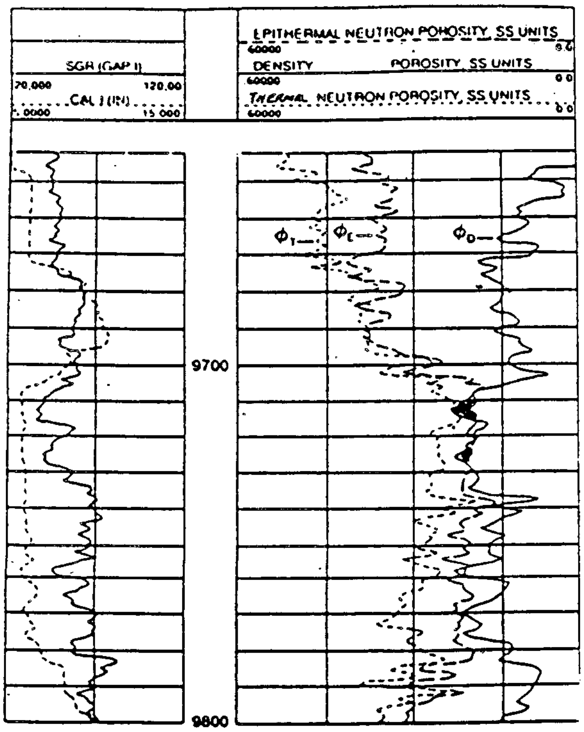

Figure 2: Miocene Sands; Offshore Aransas Co., Texas. Note Crossover (darkened) of ϕ_D and ϕ_E Logs (gas indication), and No Crossover for ϕ_D and ϕ_T Logs.

It appears that boron must be accounted for if quantitative logging calculations involving thermal neutron capture are to be reliable. We carried out studies in the Gulf Coast Frio to see if boron was present there. Twenty-seven samples of Frio sands and shales were selected for analysis, taken from the Bureau of Economic Geology Core Repository, at The University of Texas. Results are shown in Figure 2, which gives average boron content in Frio shales and sands for several counties along the Texas Gulf Coast. Boron in sands varied from 2 to 56 ppm, while shales ranged from 18 to >200 ppm. Aside from the obvious trend toward higher boron content in the shales, there is no evidence of a geographical correlation with boron content in Figure 3.

We also studied boron content in mud chemicals, and found a wide variation there. Barite from different sources had an average boron content of 54 ppm, bentonite had an average content of 34 ppm, and lignosulfonate, an average content of 45 ppm. Since these materials are present in rather small concentrations compared to the formation rock, a given content of boron in the mud chemicals will have a much smaller effect on the log than the same concentrations of boron in the reservoir rock.

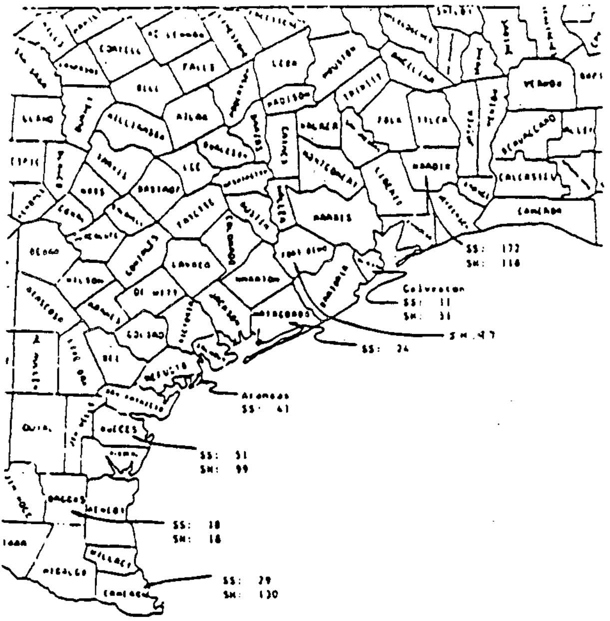

Figure 3: Average Boron Content of Frio Cores, p.p.m. SS = sandstone; SH = shale.

We have recently studied boron content in a number of cores from West Texas oil fields, where porosities are lower than in the Gulf Coast, so that a given concentration of boron has a greater effect on the log than in the high porosity Gulf Coast sands (see Figure 1). We find that boron is quite common in West Texas and, as in the Gulf Coast Frio, shales have more boron than clean sands or carbonates.

We also studied boron in oil well cements and cement additives. These can cause log interpretation errors in cased wells, if boron concentration in the cement is high. The range of boron in 14 oil well cements was 8-46 ppm. Some of the cement additives, in particular fly ash, used as a cement extender, had boron contents of 148 to 1,530 ppm. One cement additive (used to extend setting times in high temperature wells) turned out to be nearly pure borax, with 141,000 ppm boron! Details of this work have recently been submitted for publication in The Log Analyst.

We are currently beginning a study of boron in geothermal-geopressured formations along the Gulf Coast, and in various grades of casing steel. Boron in casing would be important when logging cased wells if very much is present. We understand that a small amount of boron is sometimes intentionally added to steel intended for severe service, high strength applications.

HULIN WELL LOG ANALYSES - INTRODUCTION

This well is located near Lafayette, Louisiana, and is unusual in that it contains a thick (≈500 ft.) porous (≈20%) geopressured sand at 20,210 to 20,690 ft. Maximum temperature measured in recent well logging was 340°F, and formation pressure at the bottom of the sand is about 17,500 psi. Some free gas saturation was indicated spottily through this sand by the open-hole logs run in 1979, when the well was drilled. No pulsed neutron logs were run at that time and the zone was not tested. If free gas is present in this sand, it will have a large effect on the produced gas/water ratio, and the interpretation of the production tests which are planned for this zone. To get more information on the question of free gas here, we decided to run the recently developed TDT-P, dual burst pulsed neutron log, which is based on quite different principles as compared to the resistivity logs. Unfortunately the pulsed neutron tool collapsed due to pressure before a complete logging run was made (see Figure 4). The tool should not have collapsed, as it was supposed to be safe at 22,000 psi, and the maximum well pressure was several thousand psi under this. We did, however, obtain good pulsed neutron log data in the upper 40 ft. of the sand before the tool collapsed, and here we did see evidence for free gas, confirming the resistivity log interpretation.

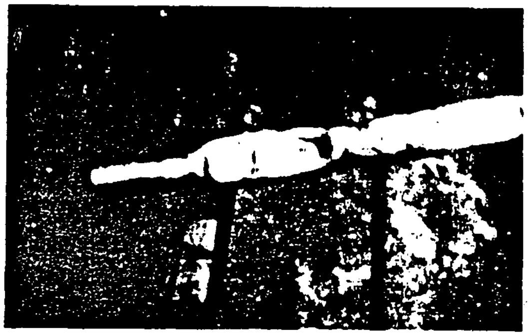

Figure 4: Collapsed Pulsed Neutron Logging Tool After Recovery from DOE Hulin #1 Well.

After the original, hand calculations were carried out we decided to do more detailed computer analyses using Schlumberger's "Elite Workstation" and "Elan" software. These let us analyze for shale, bound water, sand, gas, and bulk water content using all logs, and lets us test for consistency by comparing each log with a reconstructed log calculated from the remainder of the logs run. A "confidence level" is then calculated based on how well the observed logs match the calculated (reconstructed) logs. If any log shows a poor match between the observed and calculated versions, it can be dropped from the data set and the operation repeated to obtain a higher confidence level.

Elan Analysis Results

In the upper section of the sand, where we had both open hole resistivity logs run in 1979 and cased hole pulsed neutron logs run in 1988, we were interested in seeing how these checked when used to calculate the water saturation, We first ran the Elan model using both the open hole and cased hole logs, and then reran it dropping various logs on the basis of the match between the observed and reconstructed logs. The poorest match was for the thermal neutron porosity log. (Could boron be a problem here? The reconstructed log typically showed a lower porosity than the observed log, which would be expected if boron is present.)

Figure 5 shows the Elan output using all the logs, and the output after dropping the thermal neutron porosity log. Note the dramatic improvement in confidence level at the top of the main sand, from 20,210 to 20,250 ft., when the thermal neutron log is omitted. The reconstruction of the induction log run in open hole (not shown here) was excellent.

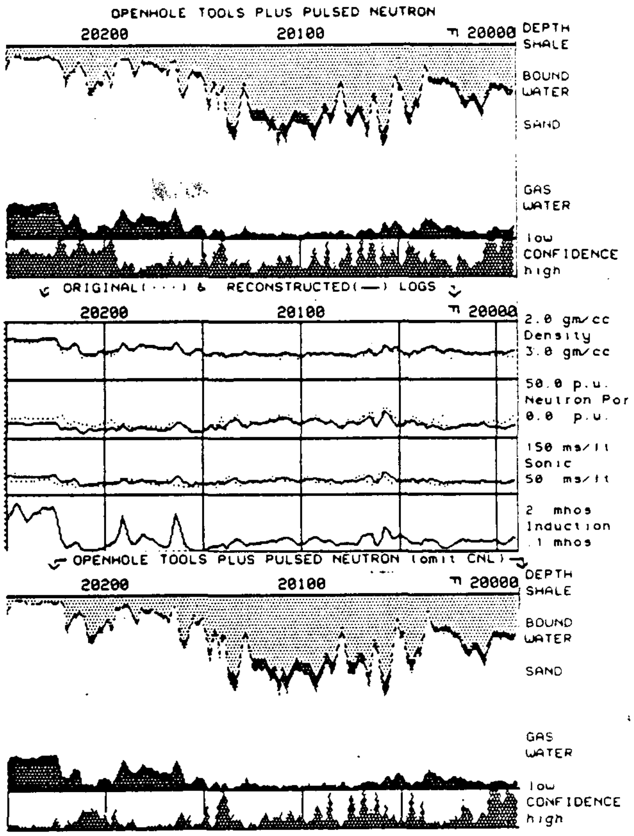

Figure 5. ELAN analysis of DOE Hulin #1 Well) (Methane).
Pulsed neutron cased hole plus all open hole logs used.
Parameters used include the following:
Σ (matrix) = 5.0 c.u. Σ hyd = 10.0 c.u. (Methane)
Σ shale = 50.0 c.u. Σ water = 95.0 c.u.
m = 2.0 Rho(matrix) = 2.65 gm/cc Rho(gas) = .285 gm/cc
n = 2.0 Δt (matrix) = 51.5 µs/ft

This good agreement between the pulsed neutron log run recently in the cased well, and the open hole resistivity logs run in 1979 gave us confidence in the reliability of the open hole logs. Figure 6 shows the Elan analysis for the entire sand thickness using only the open hole logs: first using all open hole logs, and then omitting the CNL log. Note first the small (near residual) free gas saturation over the entire 500 ft. thickness of this sand; and second, the marked increase in confidence level when the thermal neutron log (CNL) is dropped from the calculation.

The occurrence of residual gas over a sand section this thick is unusual, and unexpected. Normally the higher pressure gas in the deeper portion of the sand would dissolve in the formation water more than the lower pressure gas at the top of the sand. This dissolved gas concentration gradient would cause dissolved gas to move up through the formation water by diffusion, and if we assume that all the formation water is saturated with gas at ambient pressure, it must come out of solution as free gas at the top of the sand. The only way that conditions of residual free gas concentration over large vertical intervals could occur appears to be for the case of a very recent (geologically speaking) gas accumulation. If the accumulation had been in place for millions of years, we believe that the above solubility and diffusion effects would have transferred all the residual gas to the upper portion of the sand.

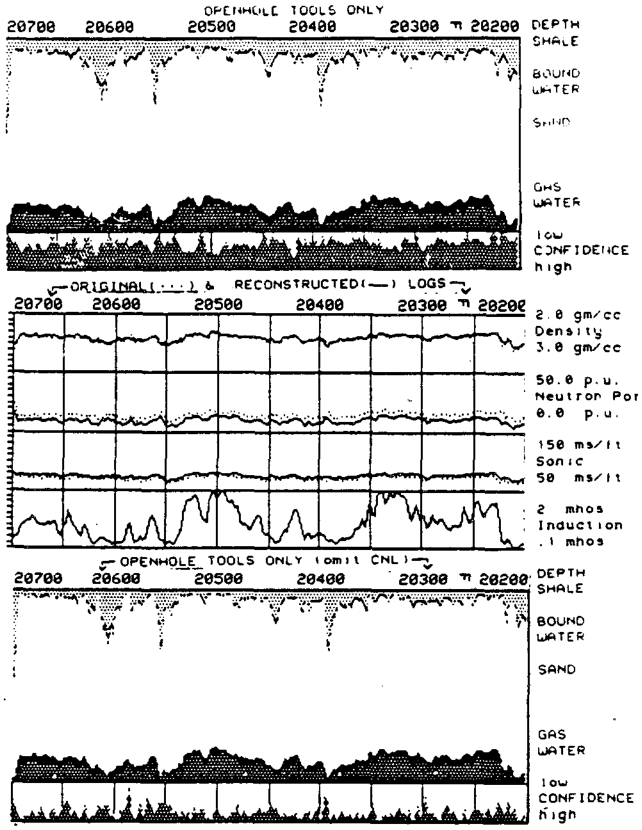

Figure 6. ELAN analysis of DOE Hulin #1 Well (Methane).
Only open hole logs used.
Parameters used include the following:
m = 2.0 Rho(matrix) = 2.65 gm/cc Rho(gas) = .285 gm/cc
n = 2.0 Δt (matrix) = 51.5 μs/ft

The large section of sand with low free gas saturation has another and more practical implication. If there is substantial dip to this formation, and if a fault or sand pinchout occurs updip from this well, there may be a large gas accumulation updip that would be of commercial importance.

References

Dunlap, H. F. and G. R. Coates, "Boron: Tracking A Trace Element," The Log Analyst, Nov.-Dec.1988, pp. 410-417.

ESTIMATION OF MUD FILTRATE RESISTIVITY IN FRESH WATER DRILLING MUDS

TOM A. LOWE AND H. F. DUNLAP

ABSTRACT

Accurate values of R_{mf} as a function of depth are needed when calculating formation water resistivity from the SP, when calculating formation factor and porosity from short investigation resistivity logs, and when interpreting the results of the repeat formation tester. Recent work has shown that the commonly used values for R_{mf} obtained from log header data are unreliable, due to large short term variations in R_m and R_{mf}. The best way to obtain R_{mf} is to measure it daily, but this is almost never done, and cannot be done on wells which have already been drilled. In some wells, however, daily measured values of R_m and mud density, but not R_{mf}, are available from mud logging units. Such data is also available from an increasing number of wells using "measurement while drilling" (MWD) systems. For these wells, we have found that accurate values of R_{mf} can be obtained using a modified form of Overton and Lipson's correlation, $R_{mf} = C(R_m)^{1.07}$, where C is an empirical function of mud density, provided that measured values of R_m and mud density are used rather than log header derived values. Overton's original correlation was for non-lignosulfonate muds, but we find that it works about as well for today's widely used lignosulfonate muds. The correlation which we recommend, based on Overton's original, non-lignosulfonate data plus considerable new data we have obtained for lignosulfonate muds, is

$$\log_{10}\left[\frac{R_{mf}}{R_m}\right] = .396 - .0475\,\rho_m \qquad (1)$$

where ρ_m is mud density in pounds per gallon. For $0.1 < R_m$ @ 75°F $< 2.0\ \Omega M$, this correlation gives a lower percent standard deviation relative to measured values of R_{mf} (26%) than other commonly used methods of estimating R_{mf} such as estimating it from log header R_{mf} data, (34%); using $R_{mf} = .75\ R_m$, (69%); and using the Overton correlation with log header R_m and ρ_m data, (67%). In the two wells where we believe we have the best data, our correlation gives a standard deviation of only 13% relative to measured values of R_{mf}. This approaches the accuracy of the basic R_m and R_{mf} measurements.

INTRODUCTION

It is necessary to know the value of the mud filtrate resistivity, R_{mf}, to be able to calculate the formation water resistivity from the SP log; or to calculate formation factor and/or porosity from short investigation resistivity logs; or to interpret the fluid recovery from the repeat formation tester. Due to the large effect of spurt loss, which occurs while the formation is being drilled, as compared to filtrate loss, occurring days and weeks later, as the hole is deepened, it is important to know R_{mf} as a function of time (depth). This will allow the best estimate of R_{mf} for a given formation of interest.

In the past the variation of R_{mf} with time (depth) has been inferred from log header values of R_{mf} for the several logging depths in a well. The assumption is that R_{mf} varies smoothly between logging depths. Recent work has shown the assumption above is not valid; R_{mf} and R_m vary considerably from day to day. In several wells where R_{mf} and R_m were measured daily, the standard deviation of the values estimated from the log header values relative to the daily measured values was 30% to 40%. [1,2,3]

Cause of this variation is complex, but certainly includes such factors as variation in amount and salinity of make up water additions to the mud; variations in amount of mud additives used such as bentonite, lignosulfonate, caustic soda, etc.; and contributions of dissolved salts and drilled up solids from new hole being made. Regardless of the causes, R_{mf} does vary considerably from day to day, and the log analyst must recognize this, and take it into account when interpreting the logs.

The ideal solution would be to measure R_m and R_{mf} daily, and to try to control some of the variables affecting R_{mf}, such as resistivity of the makeup water, in order to reduce the variation in R_{mf}. In practice, R_{mf} is not measured except when making a logging run; sometimes only once, or at most, a few times during the drilling of a well. Some mud logging units measure R_m (but not R_{mf}) daily. Also, the technique of "measurement while drilling" (MWD) is gaining wider use, and some of these systems measure R_m (but not R_{mf}) continuously. Mud engineers usually measure many properties of the mud daily, such as mud density, viscosity, pH, and filtrate loss, but not R_m or R_{mf}. A reliable method of estimating R_{mf} from R_m and mud density would be of considerable value to companies offering MWD and/or mud logging services.

Two methods have been proposed for estimating R_{mf}, given R_m. These are: Overton and Lipson's empirical correlation for non-lignosulfonate muds, $R_{mf} = C(R_m)^{1.07}$, where C is an empirical function of mud density [4,5]; and an empirical correlation given in the Schlumberger chart book, $R_{mf} = 0.75\ R_m$, mud type not specified.[5] Overton and Lipson's work was done in 1958, before lignosulfonate muds came into the wide use they enjoy today and no lignosulfonate muds are included in their data set.

This paper will evaluate the accuracy of R_{mf} estimates relative to measured R_{mf} values for Overton and Lipson's correlation; the $R_{mf} = 0.75\ R_m$ correlation; values of R_{mf} inferred from log header R_{mf} data; and a new correlation we have developed based on data given in Overton and Lipson's original paper, plus a large amount of new data we have gathered for lignosulfonate muds.

DATA AND ANALYSIS

We started our work with study of Overton and Lipson's paper.[4] It quickly became apparent that Table 1 of this paper, supposedly consisting of R_m, R_{mf} and mud density data for 94 field muds, actually contains considerable duplicated data. With a few exceptions (entries 54, 67, and 71, for example), all the data for R_m, R_{mf} and mud density for entries 1 through 45 are repeated line for line for entries 46 through 94! No such duplication was noted for the data on 47 laboratory muds, given in Table 2. Five of the entries in Table 2 were incomplete, however, lacking data for R_m, mud density, or both.

We also did not understand the need for the exponent 1.07, rather than 1.0, in Overton and Lipson's correlation, $R_{mf} = C(R_m)^{1.07}$. In an empirical relation such as this it should be possible to choose slightly different values of C as a function of mud density, and use the simpler relation $R_{mf} = K_m R_m$, without significant loss of accuracy.

We began by choosing sets of Overton's data with constant mud density (mainly from their Table 2, supplemented where possible with a few points from their Table 1), and then calculated C and the R_m exponent, m', for a given constant mud density using a linear regression to fit the logarithmic form of their relation, $\log c = \log R_{mf} - m' \log R_m$. The results are shown in Table 1. We see that both C and m' vary erratically. In fact, the weighted mean of m' for these 48 sets of (mostly) lab data is not 1.07 but 1.01. This encouraged us to search for a correlation including lignosulfonate muds similar to Overton's, but using an exponent of 1.0 instead of 1.07 for R_m.

Our experimental work was done both in the field and the laboratory. Mud densities were measured with a conventional Baroid mud balance; filtrate was obtained using a conventional 100 psig, lab temperature Baroid filter press; and R_m and R_{mf} measured with a Baroid Resistivity Meter (2 electrode) or a Schlumberger EMT-D meter (4 electrode). Both of the resistivity meters were calibrated using a series of NaCl solutions of varying salinity. We estimate the standard error of our resistivity measurements at 11%.

Table 1: C and m' for several constant mud density values, Overton and Lipson (non-lignosulfonate) data.

Mud Density (ppg)	Number of Samples (n)	C	m'
8.9	13	0.763	0.89
9.0	10	0.878	1.04
9.5	13	0.855	1.07
9.7	4	0.796	1.00
10.0	8	0.814	1.10
Weighted average of m' for all samples =			1.01

Figure 1 shows a plot of $K_m = R_{mf}/R_m$ versus mud density for Overton's non-lignosulfonate mud data. Figure 2 shows a similar plot for lignosulfonate muds used in six wells recently drilled in the Texas-Louisiana Gulf Coast area. The solid curves are "eyeball" fits to the data. Although the fitted curves are different in detail, Figure 3, showing only the two curves superimposed, demonstrates that they actually track rather well.

Figure 4 shows the lignosulfonate data using a semilog plot of K_m versus mud density, and Figure 5 is a similar plot which includes both the lignosulfonate and non-lignosulfonate data. A fit to the data of Figure 5 resulted in the equation

$$\log_{10} K_m = \log_{10}\left[\frac{R_{mf}}{R_m}\right] = 0.396 - 0.0475\ \rho_m \qquad (1)$$

where ρ_m is mud density in pounds per gallon. This equation is plotted on both Figures 4 and 5 as a solid curve, and seems a reasonable fit to both sets of data.

Table 2 gives the results of our comparison of the different commonly used methods of estimating R_{mf} from R_m. For each method, we show the % standard deviation of estimated R_{mf}, as compared to the known (measured) value of R_{mf}. We see that the results fall into three classes, regardless of mud type. The two worst methods for estimating R_{mf} are: Overton and Lipson's correlation using log header R_m data; and $R_{mf} = 0.75\ R_m$. These show standard deviations of about 68%. A better method is to estimate R_{mf} from log header R_{mf} values. This shows a standard deviation of 34%. The last two methods are best, namely: Overton and Lipson's original correlation using measured values of R_m and mud density instead of log header data; and the new correlation given by equation (1) above, also using measured R_m and mud density values. Use of equation (1) also avoids a linear interpolation from a table given in the 1985 Schlumberger Chart Book.[5] These correlations both show a standard deviation of 26%.

In only two wells were the authors directly involved in gathering the mud samples and making the measurements of R_m, R_{mf} and mud density. These were the TXO Bruce #1 well, and the Secondary Oil & Gas De Lee #1 well, both in Galveston County, Texas. For these two wells, where we are most confident of the data, the results when using our new correlation are excellent — a standard deviation of only 13% between estimated and known (measured) R_{mf} values as compared to 21% and 16% for the Overton relation using measured R_m and ρ_m data. An error of 13% approaches the accuracy of the measured R_m and R_{mf} values themselves.[6] Figures 6 & 7 show just how well the estimated and measured R_{mf} values agree for these two wells.

DISCUSSION OF RESULTS

Most of the lignosulfonate mud data we have discussed have measured R_m values between 0.1 and 2.0 ohm meters at 75°F. In one well however, the Republic Energy D & M

Table 2: Percent Standard Deviations for Various Methods of Estimating R_{mf}

Well Name, Number and Location or Other Source of Data	Number of Samples (n)	Log Header R_{mf}	$R_{mf} = .75R_m$	Overton and Lipson's Correlation Using Log Header R_m	Overton and Lipson's Correlation Using Measured R_m	R_{mf} Calculated by equ. (1)
Chevron Jose Rodriguez #1 Cameron County, Texas	98	33%	61%	106%	23%	23%
Chevron W.S. Mootheart #1 Cameron County, Texas	71	35%	113%	36%	22%	25%
Chevron Cameron Park #1 Cameron County, Texas	63	31%	51%	33%	24%	18%
TXO Production Bruce #1 Galveston County, Texas	40	34%	31%	40%	21%	13%
Chevron State Lease 932 #32 Grand Isle Block, 26, Louisiana	24	40%	40%	21%	24%	31%
Secondary Oil & Gas Inc DeLee #1	15	no openhole well logs	20%	no openhole well logs	16%	13%
Laboratory Muds Studied by Overton and Lipson (1958)	42	——	31%	——	40%	39%
Field Muds Studied by Overton and Lipson (1958)	46	——	91%	——	34%	36%
All Muds studied by Overton and Lipson (Non-Lignosulfonate)	88	——	68%	——	37%	38%
All Lignosulfonate Muds (from the six wells listed)	311	34% (n=296)	69%	67% (n=296)	23%	22%
All Muds (Includes the six wells plus Overton and Lipson's data)	399	34% (n=296)	69%	67% (n=296)	26%	26%

Cattle Co. #1, Grimes County, Texas, nearly all the measured R_m values were greater than 2.0 ohm meters at 75°F. For this well, the correlation we have developed does not predict the measured R_{mf} values well (see Figure 8). The estimated R_{mf} values track the relative changes of measured R_{mf} modestly well, but the quantitative match of estimated and measured R_{mf} is very poor, with errors approaching 100%. We do not know whether this poor result is due to bad data, or a failure of our correlation for these high R_m values. For now, we must assume the latter. Similarly, we have very little data on very saline muds. At present, we recommend use of the correlation given by equation (1) only for $0.1 < R_m < 2.0$ ohm meters at 75°F. Fortunately, this includes most "fresh water" mud systems.

CONCLUSIONS

1. The exponent 1.07 is not justified in Overton and Lipson's correlation, $R_{mf} = C(R_m)^{1.07}$. Using an exponent of 1.0 with slightly different values for C works just as well and is easier to apply.
2. Both Overton & Lipson's correlation, and a new one we have developed,

$$\log_{10}\left[\frac{R_{mf}}{R_m}\right] = 0.396 - 0.0475\ \rho_m \qquad (1)$$

work well in all types of fresh water muds, provided that: a) $.1 < R_m < 2.0$ ohm meters at 75°F, and b) *measured* values of R_m and ρ_m are used rather than values inferred from log header data.
3. Use of the correlation $R_{mf} = 0.75\ R_m$ is not advisable.
4. Use of R_{mf} values estimated from log header R_{mf} data is not advisable.
5. If possible, R_m, R_{mf}, and ρ_m should be measured daily, since they vary rapidly.
6. If measurement of R_{mf} daily is not practical, R_m and ρ_m should be measured daily, and R_{mf} estimated using equation (1).

SYMBOLS

R_m = mud resistivity; ohm meters
R_{mf} = mud filtrate resistivity; ohm meters
ρ_m = mud density; pounds per gallon
K_m = R_{mf}/R_m; dimensionless
C = $R_{mf}/(R_m)^{1.07}$; (ohm meters)$^{-0.07}$

ACKNOWLEDGMENTS

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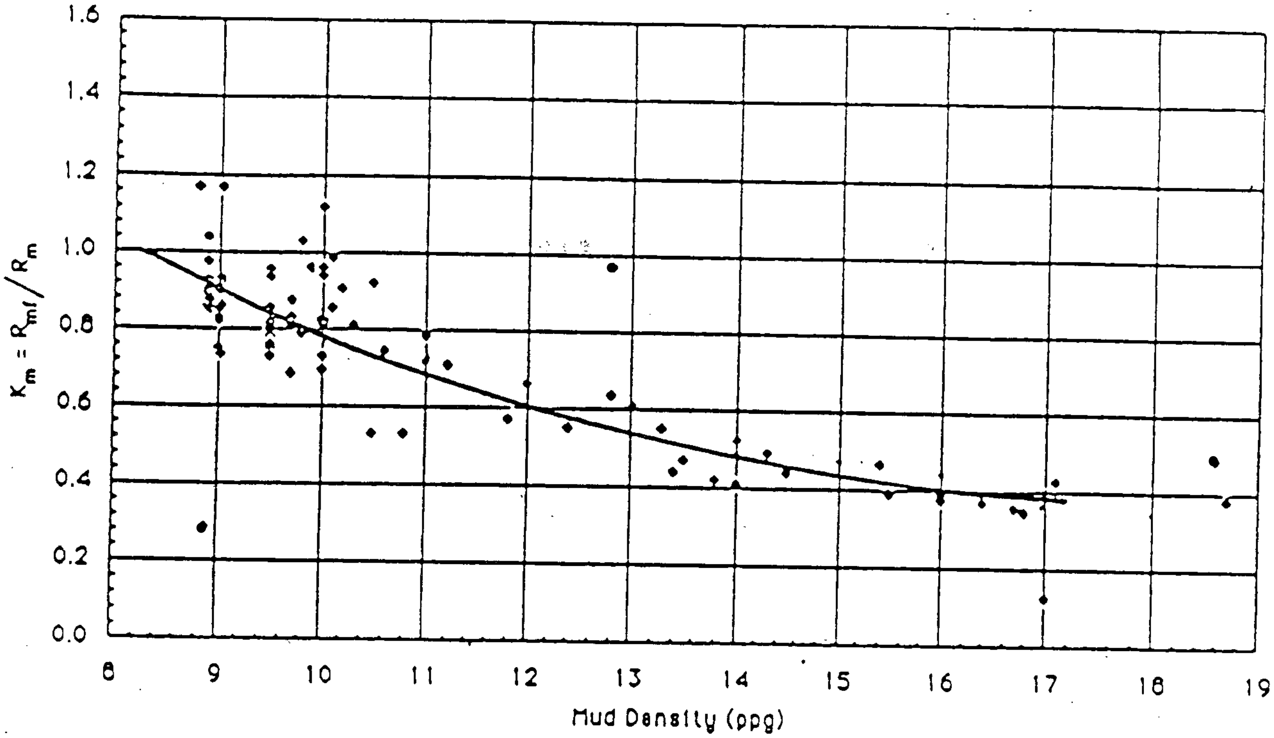

Figure 1: Km versus Mud Density, Non-Lignosulfonate Data (Overton)

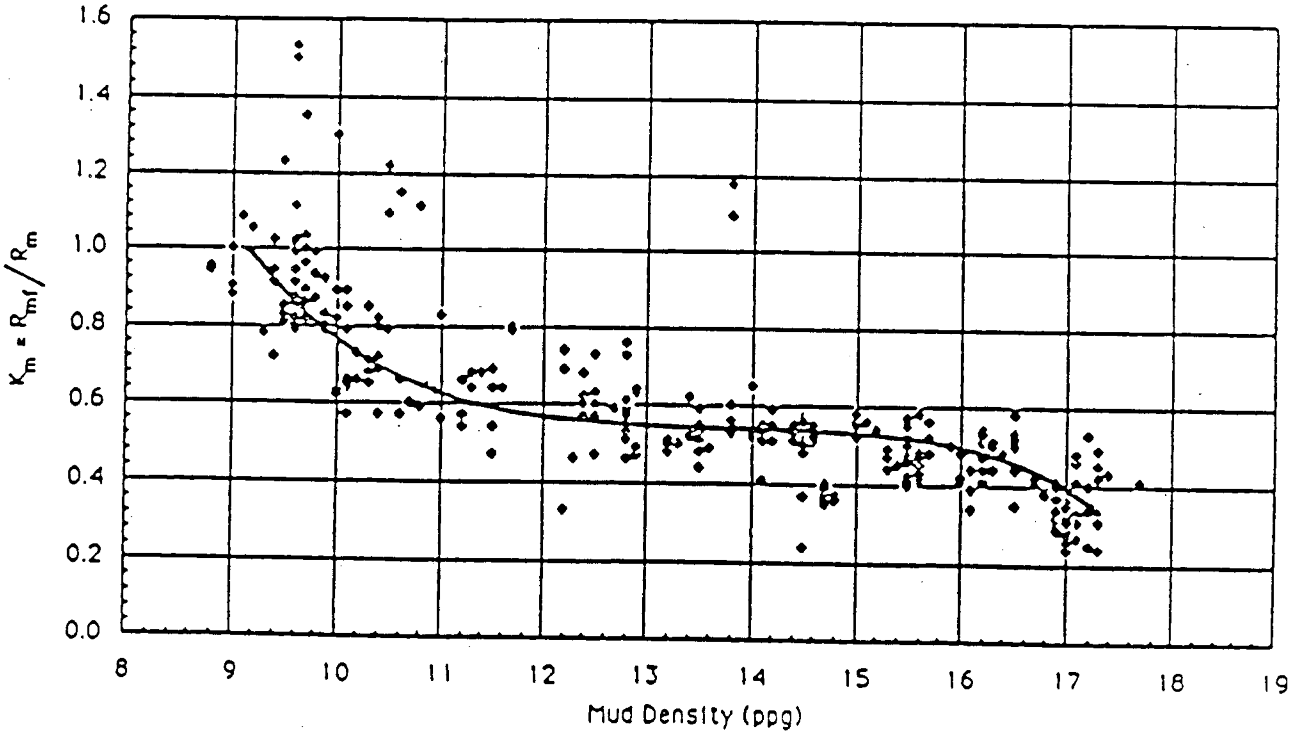

Figure 2: Km versus Mud Density, Lignosulfonate Data (Lowe)

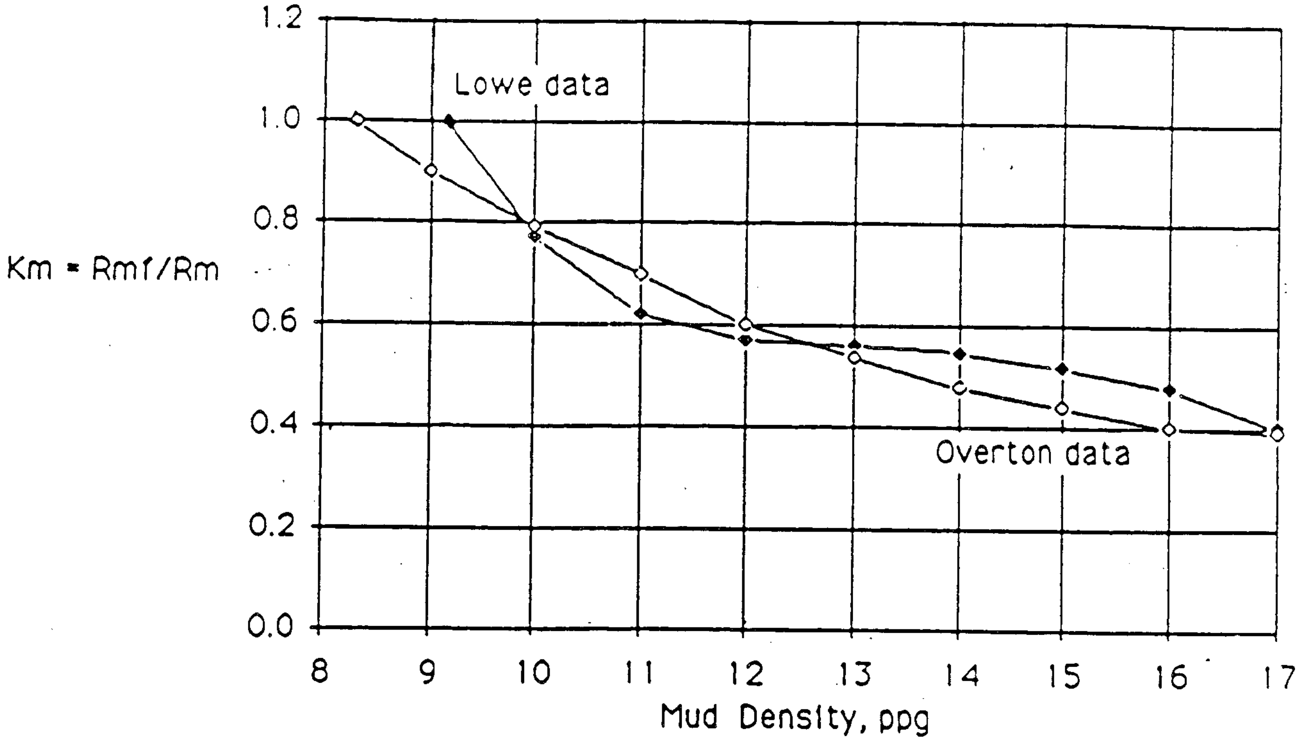

Figure 3: Km versus Mud Density

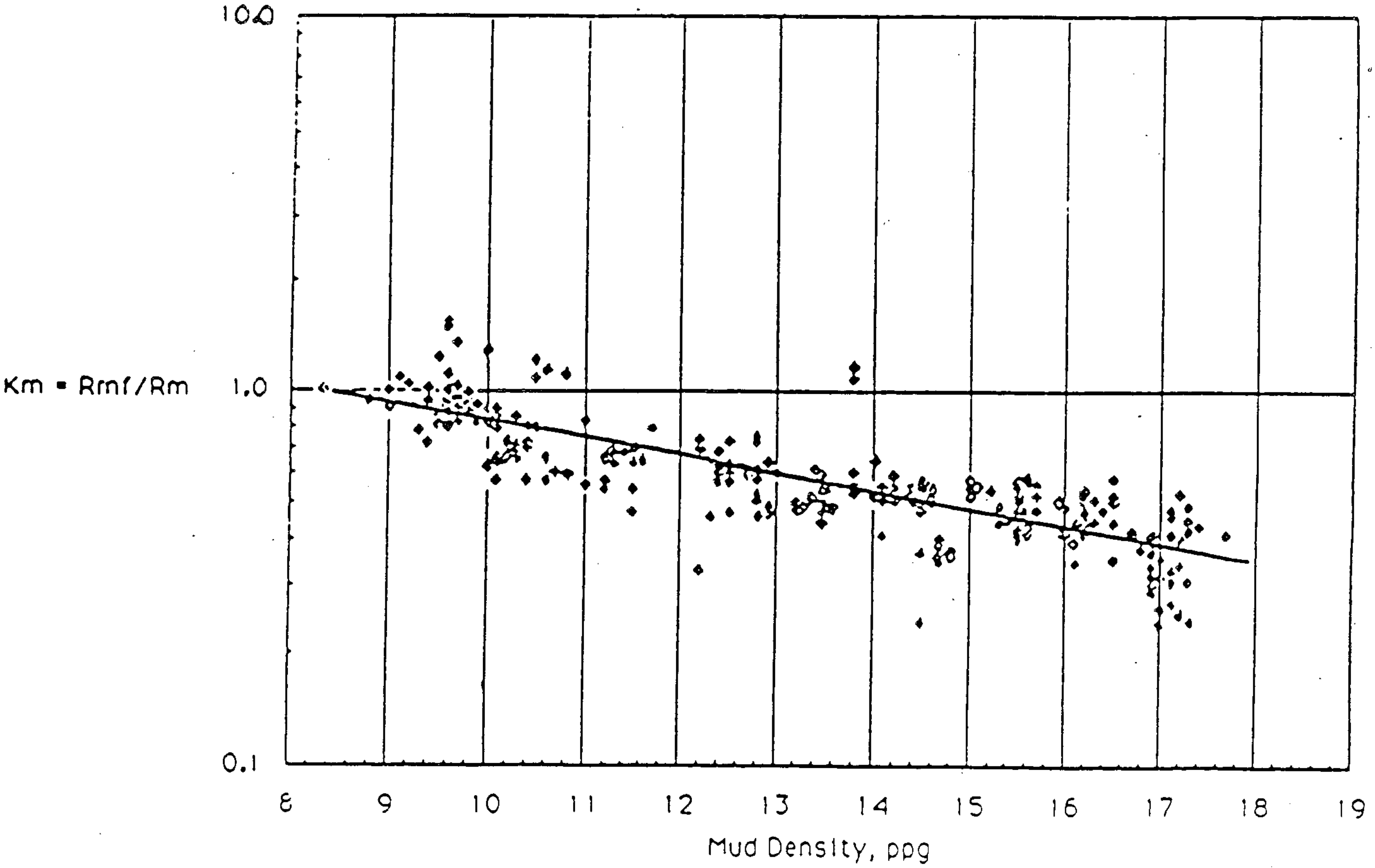

Figure 4: Km versus Mud Density, Lignosulfonate Muds

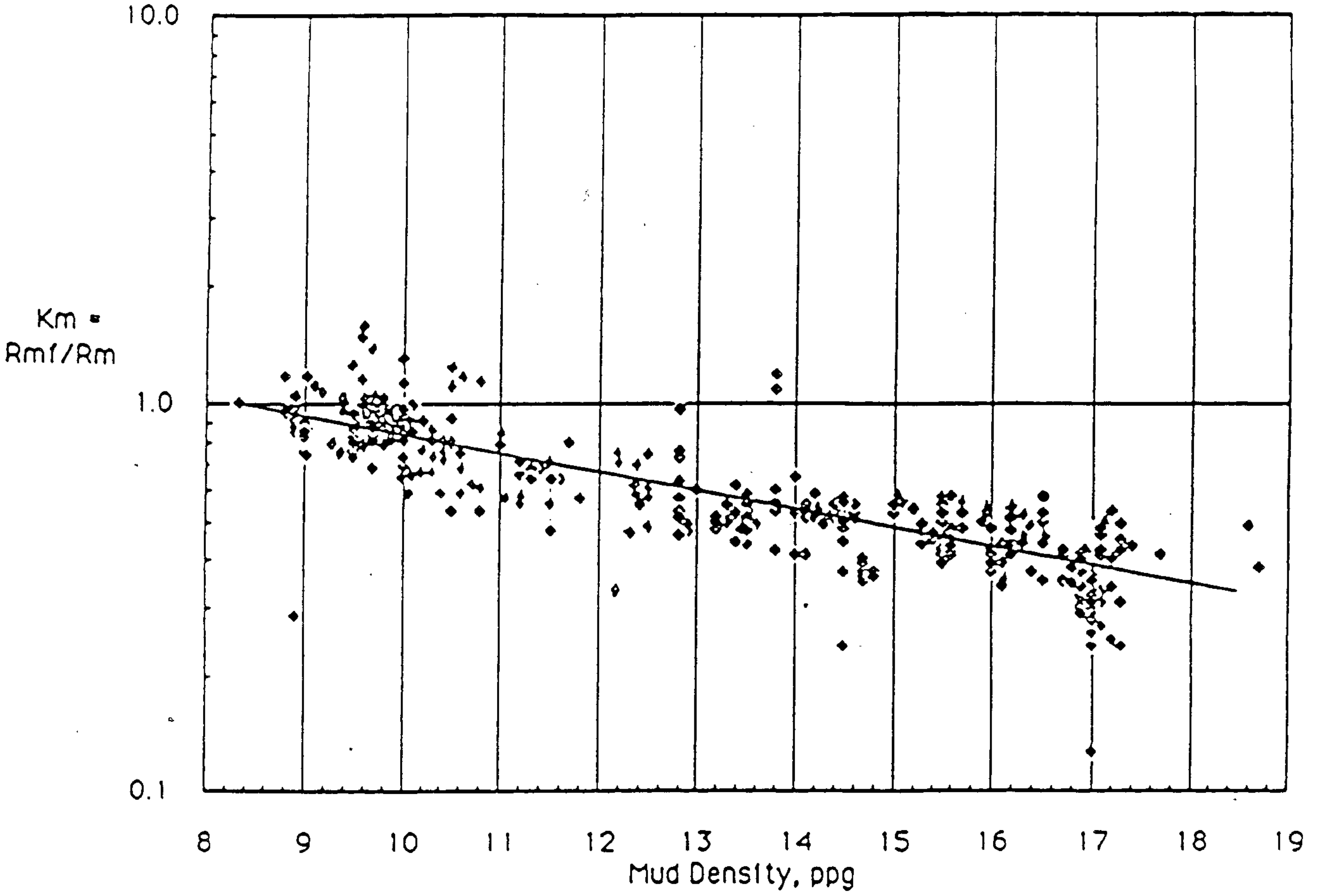

Figure 5: Km versus Mud Density, All Muds

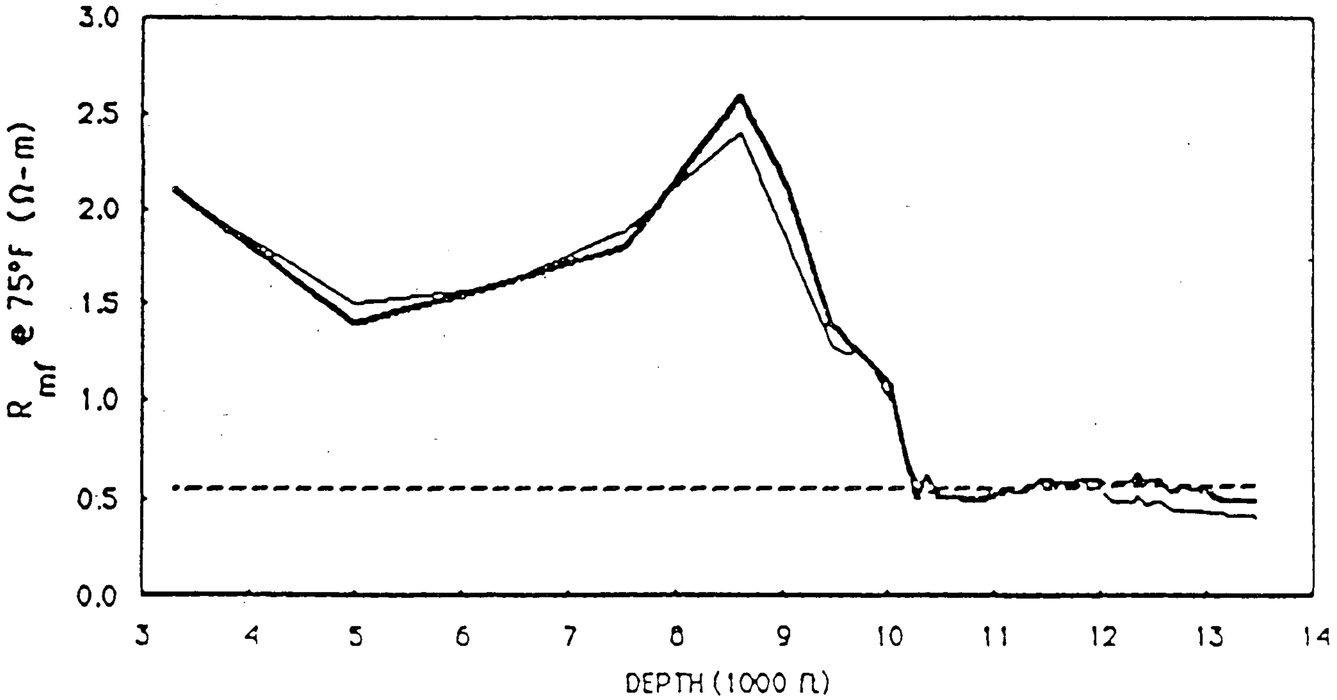

Figure 6: Rmf Vs Depth, Bruce # 1 Well; Bold: Measured Rmf; Thin: Rmf from Eq. (1); Dashed: Log header Rmf

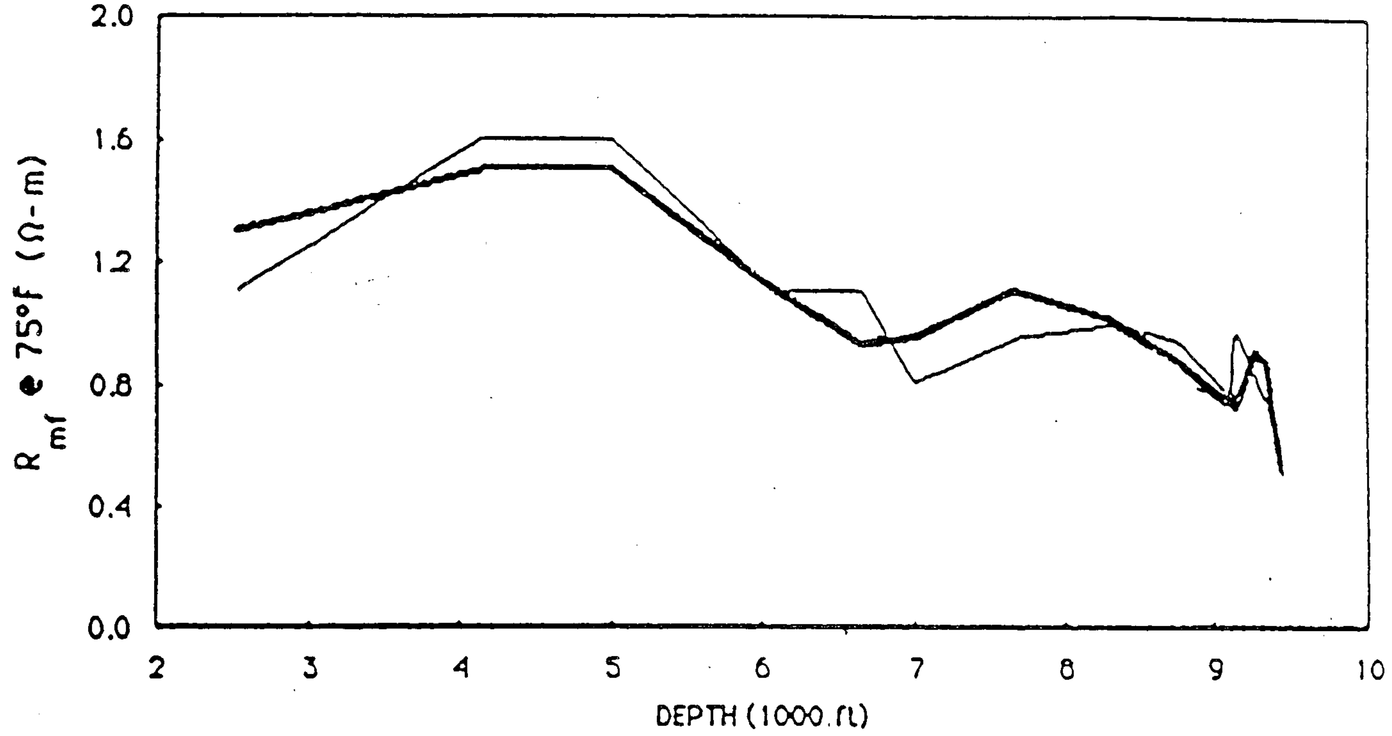

Figure 7: Rmf Vs Depth, De Lee #1 Well; Bold: Measured Rmf; Thin: Rmf from Eq. (1); No log header Rmf

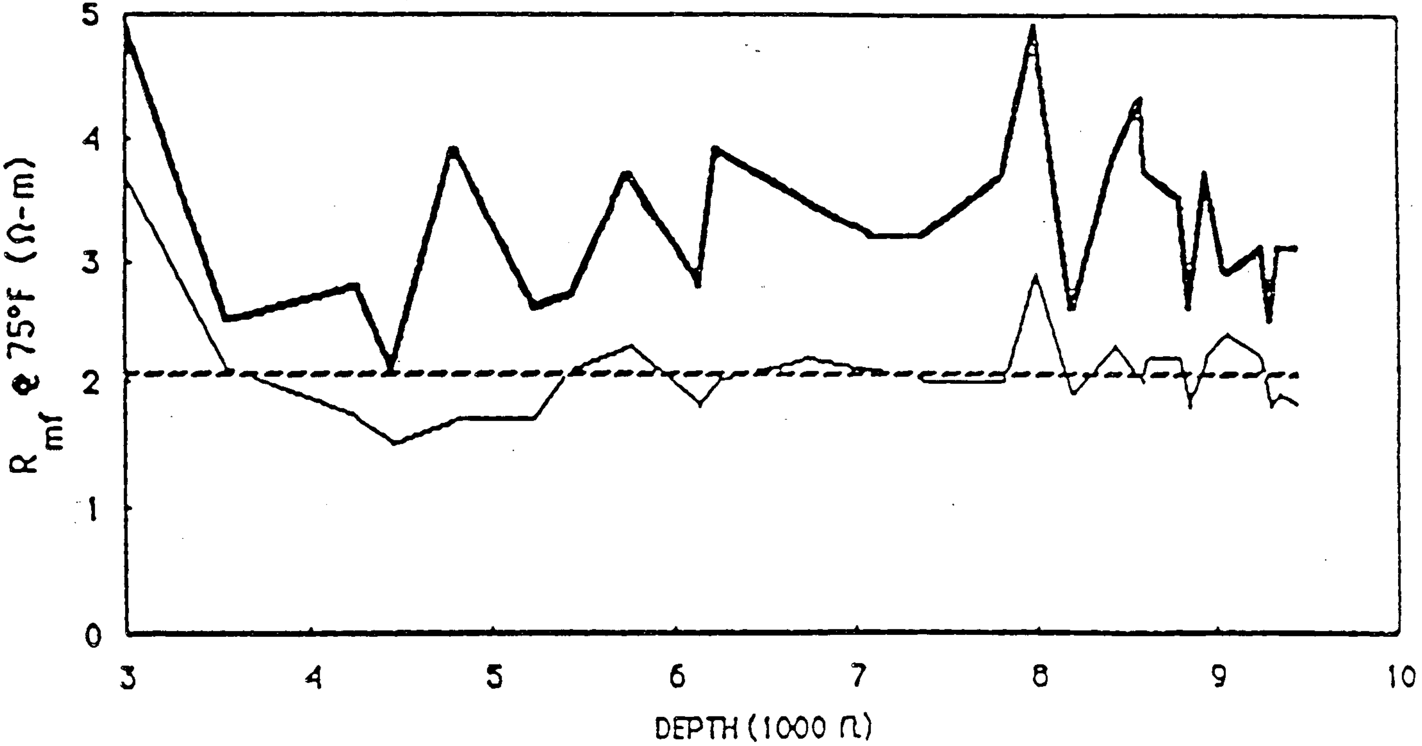

Figure 8: Rmf Vs Depth, D & M Cattle Co., #1; Bold: Measured Rmf; Thin: Rmf from Eq. (1); Dashed: Log Header Rmf