9
8-11-83 w.
II-10662

Dr. 1665
DOE/ET/27098-1

COMPUTER SIMULATION OF PRODUCTION FROM GEOTHERMAL-GEOPRESSURED AQUIFERS

Project 61025 Final Report

For the Period October 1, 1978, Through January 31, 1983

Mark G. Doherty
Nadir A. Poonawala

DOE/ET/27098--T1

DE83 015490

Prepared by
Institute of Gas Technology
IIT Center, 3424 S. State Street
Chicago, Illinois 60616

NOTICE
PORTIONS OF THIS REPORT ARE ILLEGIBLE.
It has been reproduced from the best
available copy to permit the broadest
possible availability.

Date Published — July 1983

Prepared for the
UNITED STATES DEPARTMENT OF ENERGY

Under Contract No. DE-AC08-78ET27098

MASTER

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

DISCLAIMER

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

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

REPORT DOCUMENTATION PAGE	1. REPORT NO.	2.	3. Recipient's Accession No.
4. Title and Subtitle COMPUTER SIMULATION OF PRODUCTION FROM GEOTHERMAL- GEOPRESSURED AQUIFERS			5. Report Date July 1983 (published)
7. Author(s) Mark G. Doherty and Nadir A. Poonawala			6.
9. Performing Organization Name and Address Institute of Gas Technology 3424 South State Street Chicago, Illinois 60616			8. Performing Organization Rept. No.
12. Sponsoring Organization Name and Address United States Department of Energy Nevada Operations Office P.O. Box 14100 Las Vegas, NV. 89114-4100			10. Project/Task/Work Unit No. 61025
			11. Contract(C) or Grant(G) No. (C) DE-AC08-78ET27098 (G)
			13. Type of Report & Period Covered Final Report (Oct. 1978-Jan. 1983)
15. Supplementary Notes			14.
16. Abstract (Limit: 200 words) This is the final report on research conducted to improve the technical and scientific understanding of geopressured and geothermal resources. The effort utilized a computer to interpret the results of well tests and compile data on gas solubility in brine and the viscosity of brine. A detailed computer reservoir study of a geopressured test well that had been abandoned as a dry hole but became a commercial producer of hydrocarbons is presented. A number of special topical reports pertaining to test activities performed on Department of Energy test wells (MG-T/DOE Amoco Fee No. 1 Well, Leroy Sweezy # 1 Well, and Pleasant Bayou # 2 Well) are appended to the report. A referenced article written under this study that appeared in the <u>Journal of Petroleum Technology</u> is also reproduced.			
17. Document Analysis a. Descriptors Aquifers; Brines; Gas Production; Methane; Well Tests; Permeability; Water Reservoirs; Chemical Analysis; Solubility; Viscosity; Computer Programs; Computerized Simulation b. Identifiers/Open-Ended Terms Geopressured Systems; Methane Production; Geothermal Systems; Dispersed Gas Phase; Gulf of Mexico; Formation Waters c. COSATI Field/Group 8/81			
18. Availability Statement Release Unlimited		19. Security Class (This Report) Unclassified	21. No. of Pages 231
		20. Security Class (This Page) Unclassified	22. Price (PC) A-11 (MF) A01

TABLE OF CONTENTS

	<u>Page</u>
INTRODUCTION	1
EDNA DELCAMBRE NO. 1 WELL	3
METHANE PRODUCTION FROM GEOPRESSURED AQUIFERS	4
IGT TESTING ACTIVITIES ON DOE GEOPRESSURED-GEOTHERMAL DESIGN WELLS	5
COMPARATIVE CHEMICAL ANALYSES OF G ² BRINE FROM DOE TEST WELLS	6
SOLUBILITY OF METHANE IN BRINE	8
VISCOSITY OF FORMATION WATERS	43
RESERVOIR ENGINEERING STUDIES	60
RESERVOIR STUDY OF THE G. M. KOELEMAY WELL NO. 1	61
Capillary Pressure Data	61
Reservoir and Production Data	66
Reservoir Modeling	66
Background and Geology	67
Rock Properties	70
Relative Permeability	70
Fluid Properties	71
Simulation Model	71
History Match	71
Predictions	73
Implications of the G. M. Koelemay Well No. 1	87
APPENDIX A. Methane Production From Geopressured Aquifers	A-1
APPENDIX B. IGT Test Activities on the MG-T/DOE Amoco Fee No. 1 Well During August, 1981	B-1
APPENDIX C. IGT Testing Activities on the Leroy Sweezy #1 Well During September 1982	C-1
APPENDIX D. Tables of Methane Solubility in Brine Based on System Science & Software, Blount, and Haas Equations	D-1
APPENDIX E. Do We Know Whether the Pleasant Bayou #2 is Saturated With Methane?	E-1
APPENDIX F. Tables of Absolute Viscosity of NaCl Solutions	F-1

MASTER

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

LIST OF FIGURES

<u>Figure No.</u>		<u>Page</u>
1	Solubility of Methane in Brine at 200°F (S ³)	9
2	Solubility of Methane in Brine at 210°F (S ³)	10
3	Solubility of Methane in Brine at 220°F (S ³)	11
4	Solubility of Methane in Brine at 230°F (S ³)	12
5	Solubility of Methane in Brine at 240°F (S ³)	13
6	Solubility of Methane in Brine at 250°F (S ³)	14
7	Solubility of Methane in Brine at 260°F (S ³)	15
8	Solubility of Methane in Brine at 270°F (S ³)	16
9	Solubility of Methane in Brine at 280°F (S ³)	17
10	Solubility of Methane in Brine at 290°F (S ³)	18
11	Solubility of Methane in Brine at 300°F (S ³)	19
12	Solubility of Methane in Brine at 200°F (Blount)	20
13	Solubility of Methane in Brine at 210°F (Blount)	21
14	Solubility of Methane in Brine at 220°F (Blount)	22
15	Solubility of Methane in Brine at 230°F (Blount)	23
16	Solubility of Methane in Brine at 240°F (Blount)	24
17	Solubility of Methane in Brine at 250°F (Blount)	25
18	Solubility of Methane in Brine at 260°F (Blount)	26
19	Solubility of Methane in Brine at 270°F (Blount)	27
20	Solubility of Methane in Brine at 280°F (Blount)	28
21	Solubility of Methane in Brine at 290°F (Blount)	29
22	Solubility of Methane in Brine at 300°F (Blount)	30
23	Solubility of Methane in Brine at 200°F (Haas)	31
24	Solubility of Methane in Brine at 210°F (Haas)	32
25	Solubility of Methane in Brine at 220°F (Haas)	33

LIST OF FIGURES, Cont.

<u>Figure No.</u>		<u>Page</u>
26	Solubility of Methane in Brine at 230°F (Haas)	34
27	Solubility of Methane in Brine at 240°F (Haas)	35
28	Solubility of Methane in Brine at 250°F (Haas)	36
29	Solubility of Methane in Brine at 260°F (Haas)	37
30	Solubility of Methane in Brine at 270°F (Haas)	38
31	Solubility of Methane in Brine at 280°F (Haas)	39
32	Solubility of Methane in Brine at 290°F (Haas)	40
33	Solubility of Methane in Brine at 300°F (Haas)	41
34	Viscosity of Brine Solutions at 1000 psi	44
35	Viscosity of Brine Solutions at 2000 psi	45
36	Viscosity of Brine Solutions at 3000 psi	46
37	Viscosity of Brine Solutions at 4000 psi	47
38	Viscosity of Brine Solutions at 5000 psi	48
39	Viscosity of Brine Solutions at 6000 psi	49
40	Viscosity of Brine Solutions at 7000 psi	50
41	Viscosity of Brine Solutions at 8000 psi	51
42	Viscosity of Brine Solutions at 9000 psi	52
43	Viscosity of Brine Solutions at 10,000 psi	53
44	Viscosity of Brine Solutions at 11,000 psi	54
45	Viscosity of Brine Solutions at 12,000 psi	55
46	Viscosity of Brine Solutions at 13,000 psi	56
47	Viscosity of Brine Solutions at 14,000 psi	57
48	Viscosity of Brine Solutions at 15,000 psi	58
49	Capillary Pressure Curves	65

LIST OF FIGURES, Cont.

<u>Figure No.</u>		<u>Page</u>
50	Generalized Structure Map	68
51	Yegua "Leger" Sand Cross-Section	69
52	Brine Production Rate for G. M. Koelemay Well No. 1	75
53	Bottomhole Pressure History Match for G. M. Koelemay Well No. 1	76
54	Gas Production Rate History Match for G. M. Koelemay Well No. 1	77
55	Gas-Brine Ratio History Match for G. M. Koelemay Well No. 1	78
56	Cumulative Brine Production for G. M. Koelemay Well No. 1	79
57	Predicted Bottomhole Pressure for G. M. Koelemay Well No. 1	82
58	Predicted Gas Production Rate for G. M. Koelemay Well No. 1	83
59	Predicted Gas-Brine Ratio for G. M. Koelemay Well No. 1	84
60	Predicted Cumulative Gas Production for G. M. Koelemay Well No. 1	85
61	Predicted Cumulative Brine Production for G. M. Koelemay Well No. 1	86

LIST OF TABLES

<u>Table No.</u>		<u>Page</u>
1	Results of the Analysis of the McNeese State University Comparison Samples	7
2	Relevant Core Data	62
3	Capillary Pressure Data — Frio #17	63
4	Capillary Pressure Data — Frio #82	64
5	Rock Properties	70
6	Relative Permeability	70
7	Fluid Properties	71
8	Gas PVT Data	72
9	Water PVT Data	72
10	Performance Summary of the G. M. Koelemay Well No. 1	74
11	Predicted Reservoir Performance Summary at 2000 BPD	80
12	Predicted Reservoir Performance Summary at 1000 BPD	81

INTRODUCTION

This document is the final report for "Computer Simulation of Production From Geothermal-Geopressured Aquifers," Contract Number DE-AC08-78ET27098 (originally contract number ET-78-C-08-1600). The contract, which began October 1, 1978, was originally funded for a 2-year period. As time progressed the contract was renewed and continued until January 31, 1983.

This research contract originated because of the test results from the Department of Energy's (DOE) first geopressured-geothermal aquifer, the Edna Delcambre No. 1 Well, which produced an unexpected gas flow. This anomalous well behavior was unexplained, and an understanding of it would have significant implications for the resulting technical and economic aspects of the national geopressured-geothermal energy program. Gas in excess of the quantities dissolved in the brine was produced, and several theories were suggested to explain its origin. Thus, this project was funded to evaluate in detail some of the possible theories explaining the Delcambre well test results, and then to continue analytical work on other wells of interest to the DOE national geopressured-geothermal (G²) program.

The main theory evaluated in detail was the dispersed gas phase theory, which followed some preliminary work at the Institute of Gas Technology (IGT). This work indicated that if a certain relationship occurred in the relative permeability of gas and water combined with a certain gas generation and trapping mechanism, then a dispersed gas phase could be generated; this could account for the anomalous gas production. Then, on the assumption that this theory could be used to match the experimental data, calculations of gas production and the related economic projections could be made for variations in the physical production mechanisms. The work originally was divided into three phases:

- Phase I — Analysis Based on Existing Data
- Phase II — Analysis of New Well Test Data
- Phase III — Incorporating Lab Data in Projections.

This evolved into the following tasks and subtasks:

- Task 1. Analyses Based on Existing Data
 - Subtask 1-1. Review of Wells of Opportunity Data
 - Subtask 1-2. Parametric Economic Analyses
- Task 2. Analyses of Design Well Test Data
 - Subtask 2-1. Additional Well Test Data
 - Subtask 2-2. Additional Parametric Economic Analyses
 - Subtask 2-3. Sample Collection and Analysis of DOE-DOW Parc Perdue Design Well
- Task 3. Incorporation of Laboratory Data in Projects
 - Subtask 3-1. Refinement of the Interpretation of DOE Well Test Data
 - Subtask 3-2. Updated Parametric Economic Analysis
- Task 4. Recommendation for Research Critical to the Geothermal-Geopressured Program

The work defined above was predicated on the fact that data would become available from tests of Design Wells and Wells of Opportunity and from laboratory research for incorporation into this study. As such, this contract was utilized to provide special analyses and independent assessments to further the understanding of gas production from geopressured-geothermal aquifers. IGT's role became one of maintaining technical awareness of other projects and collecting and interpreting data meaningful to the national G² program that might not have been utilized in the context of individual project details. To achieve timely availability of these results, topical reports were presented at numerous technical conferences and at the DOE/Industry G² Forum. Some special reports were prepared in response to specific DOE requests.

This final report covers a broad spectrum of research activities. Some work will be referenced to the appropriate journal or proceedings in which it was originally published. This final report will provide details on the more recent research that has not been widely disseminated.

EDNA DELCAMBRE NO. 1 WELL

This G² well produced gas in excess of that which could be in solution in the aquifer. A number of theories were put forth to explain this unusual behavior. One of the theories regarding the excess gas was that its source was a nearby gas cap, which was not initially in contact with the well but became connected as pressure around the well was lowered during production. The gas would then cone down into the well. Another theory was that the excess gas existed initially as a dispersed phase of small to microscopic-sized bubbles in the reservoir rock matrix. With this theory, production of the excess, or free gas, would occur as the pressure was lowered around the well such that the expanding small bubbles would increase gas saturation to the point where the gas would no longer be trapped, but would flow in accordance with relative permeability considerations. A third theory was that the gas was all initially dissolved, but as the pressure was lowered around the well by rapid production, gas exsolved from the solution and migrated to the top of the reservoir, where it was produced like a gas cap. A fourth theory was that the gas came from a zone above or below the perforated interval, the free gas having moved through a channel in the cement annulus between the well casing and the well-bore wall. This could have resulted from a poor cement job. A fifth theory was that the gas came from the nearby Edna Delcambre No. 4 or No. 4A well, which had a flow path in its wellbore or annulus.

IGT analyses led to the conclusion that the most likely source for the excess gas appeared to be from a yet undetermined gas zone which became connected to the No. 1 sand via a conduit around the No. 4 or No. 4A well bore. This conclusion stimulated a good deal of discussion about the free gas source. The ensuing debates permitted numerous individuals to discuss the G² resource in an open forum and provided a significant contribution to furthering research efforts.

Results of this research were presented at the Fourth United States Gulf Coast Geopressured-Geothermal Energy Conference at the University of Texas at Austin during October 29-31, 1979. The paper was titled the "Ratio of Produced Gas to Water from DOE's Edna Delcambre No. 1 Geopressured-Geothermal Aquifer Gas Well Test."

METHANE PRODUCTION FROM GEOPRESSURED AQUIFERS

To treat the parametric economic analyses under the contract, IGT developed the user-friendly computer program "ECONANAL," which was specifically tailored to handle the economic and financial aspects of production from G^2 formations. This work was reported in an SPE paper (#9468) and presented at the 55th Annual Fall Technical Conference and Exhibition of the Society of Petroleum Engineers of AIME in Dallas, Texas, on September 21-24, 1980. This paper was reviewed, updated, and expanded for publication in the Journal of Petroleum Technology (July 1982). The paper in its final form, titled "Methane Production From Geopressured Aquifers," is attached as Appendix A. The referred journal article details parametric economic analyses performed under this contract.

IGT TESTING ACTIVITIES ON DOE GEOPRESSURED-GEOTHERMAL DESIGN WELLS

IGT supported the DOE G² program by conducting independent analyses of fluids production from two DOE Design Wells, the MG-T/DOE Amoco Fee No. 1 and the Leroy Sweezy #1 Well. The reports answered four questions:

- What quantity and quality of gas left the separator still dissolved in the disposal brine?
- Was the reservoir saturated with gas?
- In what ways did the chemistry of the produced brine affect the gas behavior and partitioning between phases?
- Was the produced oil dissolved in the brine at reservoir conditions?

Appendix B details the results of work on the MG-T/DOE Amoco Fee No. 1 Well and Appendix C describes the work and conclusions on the Leroy Sweezy #1 Well. It should be noted that the work on the MG-T/DOE Amoco Fee No. 1 Well resulted from a combined effort made possible by joint funding by DOE and the Gas Research Institute (GRI) for ongoing G² research activities at IGT.

COMPARATIVE CHEMICAL ANALYSES OF G² BRINE FROM DOE TEST WELLS

As part of work performed for the DOE Division of Geothermal Energy (DGE), IGT analyzed brine samples from several well tests, namely: Pleasant Bayou No. 2, Fairfax-Foster Sutter, and Buelah Simon. These chemical analyses are useful for two purposes. First, an understanding of the chemical composition of the brine informs us of any particular problems that might be encountered in simulating the performance of the reservoir as well as any adverse effects on the economics of long-term production due to scaling, corrosion, and plugging of the disposal well. Second, and of considerable practical importance, is that they provide a check on the results of the chemical analyses against the findings of other laboratories performing the same tests.

The methods used to analyze the fluids for various elements and compounds are described in "Standard Sampling and Analytical Methods for Geopressured Fluids" prepared for DOE by McNeese State University under Gas Research Institute Contract No. 5080-321-0301. IGT chemists used the primary procedures outlined in the referenced document except where neutron activation analysis was recommended. Rather than using neutron activation, which can be quite time-consuming due to long delays between activation and measurement, the alternate procedure of atomic adsorption (AA) spectrometry was employed. Detailed results of the brine analyses are shown in Table 1. The brines were analyzed for the concentrations of: arsenic, barium, boron, cadmium, calcium, chromium, copper, iron, lead, magnesium, manganese, mercury, potassium, sodium, and zinc. Concentrations of ammonia, chlorides, fluorides, silica, and sulfates are also reported.

Table 1. RESULTS OF THE ANALYSIS OF THE McNEESE STATE UNIVERSITY
COMPARISON SAMPLES

<u>Parameter</u>	<u>Units</u>	<u>Fairfax-Foster Sutter #2</u>	<u>Pleasant Bayou</u>	<u>Beulah Simon #2</u>
Chlorides (Cl^-)	mg/l	97,000	76,000	52,000
Fluorides (F^-)	mg/l	0.92	1.50	0.70
Sulfate (SO_4^{2-})	mg/l	<5	<5	720
Ammonia (NH_3)	mg/l	64	62	30
Silica (SiO_2)	mg/l	30	60	40
Arsenic (As)	$\mu\text{g/l}$	15	5.4	<1.6
Boron (B)	mg/l	42	27	75
Barium (Ba)	mg/l	250	820	1.0
Calcium (Ca)	mg/l	7,500	8,800	3,100
Cadmium (Cd)	$\mu\text{g/l}$	12	0.36	37
Chromium (Cr)	$\mu\text{g/l}$	58	<10	25
Copper (Cu)	$\mu\text{g/l}$	9.1	170	7.9
Iron (Fe)	mg/l	49	59	66
Potassium (K)	mg/l	860	590	510
Mercury (Hg)	$\mu\text{g/l}$	5.8	0.71	0.76
Magnesium (Mg)	mg/l	680	660	280
Manganese (Mn)	mg/l	17	23	4.0
Sodium (Na)	mg/l	54,000	35,000	29,000
Lead (Pb)	$\mu\text{g/l}$	50	29	4.5
Strontium (Sr)	mg/l	600	990	280
Zinc (Zn)	mg/l	1.8	0.79	0.19

mg/l equivalent to parts per million (ppm)

$\mu\text{g/l}$ equivalent to parts per billion (ppb)

SOLUBILITY OF METHANE IN BRINE

The solubility of methane in pure water has been studied exhaustively. However, the solubility of methane in brines of various salinities is known with a lesser degree of certainty. In addition, the data are often dispersed among various source documents and in scientific units not consistent with standard oil field usage. To unify these data and make the information useful for the G^2 program, IGT analyzed three different interpretations of methane solubility in brine as developed by various researchers. Utilizing the work performed by these researchers, IGT calculated the solubility of methane for pressures ranging from 1,000 to 15,000 psi, temperatures from 200° to 300°F, and salinities of 0 to 25 weight percent. These ranges were selected based on previous experience on the G^2 program, but methane solubility data can be generated easily for higher temperatures and/or greater pressures or salinities because the governing parametric equations are programmed for a microcomputer.

The three basic algorithms used to generate the solubility data were developed by Systems Science & Software (S^3), Professor Charles Blount of Idaho State University, and Dr. J. L. Haas of the U. S. Geological Survey. IGT developed the computer program incorporating these algorithms for a side-by-side comparison of the results in customary oil field units. The tables in Appendix D detail the results of the computations.

In addition to the tabular form in Appendix D, IGT plotted families of curves for the three algorithms. Figures 1 to 11 show the S^3 solubility of methane for 200°F to 300°F, Figures 12 to 22 graphically represent the Blount equation, and Figures 23 to 33 plot the results of the Haas equation.

These figures provide good approximations of the expected gas saturations for specific conditions. However, the formations tested to date under the G^2 program contained varying compositions of gases that included methane, ethane, propane, butanes, pentanes, hexanes, higher hydrocarbons, carbon dioxide, and nitrogen. The combined effects of these constituents in actually determining gas saturation in a given brine are not thoroughly understood. As a result, these figures really provide an estimate for the expected saturation of the gas in brine. Furthermore, the chemical compositions of the brines encountered in well tests contained more elements than did the sodium chloride solutions used to empirically determine methane solubilities in the laboratory

SOLUBILITY OF METHANE IN BRINE @ 200 deg.F (SYSTEMS SCIENCE & SOFTWARE EQUATION)

Figure 1. SOLUBILITY OF METHANE IN BRINE AT 200°F (S³)

SOLUBILITY OF METHANE IN BRINE @ 210 deg.F (SYSTEMS SCIENCE & SOFTWARE EQUATION)

Figure 2. SOLUBILITY OF METHANE IN BRINE AT 210°F (S³)

SOLUBILITY OF METHANE IN BRINE @ 220 deg.F (SYSTEMS SCIENCE & SOFTWARE EQUATION)

Figure 3. SOLUBILITY OF METHANE IN BRINE AT 220°F (S³)

Figure 4. SOLUBILITY OF METHANE IN BRINE AT 230°F (S³)

SOLUBILITY OF METHANE IN BRINE @ 240 deg.F (SYSTEMS SCIENCE & SOFTWARE EQUATION)

Figure 5. SOLUBILITY OF METHANE IN BRINE AT 240°F (S³)

SOLUBILITY OF METHANE IN BRINE @ 250 deg.F (SYSTEMS SCIENCE & SOFTWARE EQUATION)

Figure 6. SOLUBILITY OF METHANE IN BRINE AT 250°F (S³)

SOLUBILITY OF METHANE IN BRINE @ 260 deg.F (SYSTEMS SCIENCE & SOFTWARE EQUATION)

Figure 7. SOLUBILITY OF METHANE IN BRINE AT 260°F (S³)

SOLUBILITY OF METHANE IN BRINE @ 270 deg.F (SYSTEMS SCIENCE & SOFTWARE EQUATION)

Figure 8. SOLUBILITY OF METHANE IN BRINE AT 270°F (S³)

SOLUBILITY OF METHANE IN BRINE @ 280 deg.F (SYSTEMS SCIENCE & SOFTWARE EQUATION)

Figure 9. SOLUBILITY OF METHANE IN BRINE AT 280°F (S³)

SOLUBILITY OF METHANE IN BRINE @ 290 deg.F (SYSTEMS SCIENCE & SOFTWARE EQUATION)

Figure 10. SOLUBILITY OF METHANE IN BRINE AT 290°F (S³)

SOLUBILITY OF METHANE IN BRINE @ 300 deg.F (SYSTEMS SCIENCE & SOFTWARE EQUATION)

Figure 11. SOLUBILITY OF METHANE IN BRINE AT 300°F (S³)

SOLUBILITY OF METHANE IN BRINE @ 200 deg.F (BLOUNT EQUATION)

Figure 12. SOLUBILITY OF METHANE IN BRINE AT 200°F (Blount)

SOLUBILITY OF METHANE IN BRINE @ 210 deg.F (BLOUNT EQUATION)

Figure 13. SOLUBILITY OF METHANE IN BRINE AT 210°F (Blount)

SOLUBILITY OF METHANE IN BRINE @ 220 deg.F (BLOUNT EQUATION)

Figure 14. SOLUBILITY OF METHANE IN BRINE AT 220°F (Blount)

SOLUBILITY OF METHANE IN BRINE @ 230 deg.F (BLOUNT EQUATION)

Figure 15. SOLUBILITY OF METHANE IN BRINE AT 230°F (Blount)

SOLUBILITY OF METHANE IN BRINE @ 240 deg.F (BLOUNT EQUATION)

Figure 16. SOLUBILITY OF METHANE IN BRINE AT 240°F (Blount)

SOLUBILITY OF METHANE IN BRINE @ 250 deg.F (BLOUNT EQUATION)

Figure 17. SOLUBILITY OF METHANE IN BRINE AT 250°F (Blount)

SOLUBILITY OF METHANE IN BRINE @ 260 deg.F
(BLOUNT EQUATION)

Figure 18. SOLUBILITY OF METHANE IN BRINE AT 260°F (Blount)

SOLUBILITY OF METHANE IN BRINE @ 270 deg.F (BLOUNT EQUATION)

Figure 19. SOLUBILITY OF METHANE IN BRINE AT 270°F (Blount)

SOLUBILITY OF METHANE IN BRINE @ 280 deg.F (BLOUNT EQUATION)

Figure 20. SOLUBILITY OF METHANE IN BRINE AT 280°F (Blount)

SOLUBILITY OF METHANE IN BRINE @ 290 deg.F (BLOUNT EQUATION)

Figure 21. SOLUBILITY OF METHANE IN BRINE AT 290°F (Blount)

SOLUBILITY OF METHANE IN BRINE @ 300 deg.F (BLOUNT EQUATION)

Figure 22. SOLUBILITY OF METHANE IN BRINE AT 300°F (Blount)

Figure 23. SOLUBILITY OF METHANE IN BRINE AT 200°F (Haas)

SOLUBILITY OF METHANE IN BRINE @ 210 deg.F (CHAAS EQUATION)

Figure 24. SOLUBILITY OF METHANE IN BRINE AT 210°F (Haas)

SOLUBILITY OF METHANE IN BRINE @ 220 deg.F (CHAAS EQUATION)

Figure 25. SOLUBILITY OF METHANE IN BRINE AT 220°F (Haas)

SOLUBILITY OF METHANE IN BRINE @ 230 deg.F (CHAAS EQUATION)

Figure 26. SOLUBILITY OF METHANE IN BRINE AT 230°F (Haas)

SOLUBILITY OF METHANE IN BRINE @ 240 deg.F (CHAAS EQUATION)

Figure 27. SOLUBILITY OF METHANE IN BRINE AT 240°F (Haas)

SOLUBILITY OF METHANE IN BRINE @ 250 deg.F (HAAS EQUATION)

Figure 28. SOLUBILITY OF METHANE IN BRINE AT 250°F (Haas)

SOLUBILITY OF METHANE IN BRINE @ 260 deg.F (CHAAS EQUATION)

Figure 29. SOLUBILITY OF METHANE IN BRINE AT 260°F (Haas)

SOLUBILITY OF METHANE IN BRINE @ 270 deg.F (CHAAS EQUATION)

Figure 30. SOLUBILITY OF METHANE IN BRINE AT 270°F (Haas)

SOLUBILITY OF METHANE IN BRINE @ 280 deg.F (CHAAS EQUATION)

Figure 31. SOLUBILITY OF METHANE IN BRINE AT 280°F (Haas)

SOLUBILITY OF METHANE IN BRINE @ 290 deg.F (CHAAS EQUATION)

Figure 32. SOLUBILITY OF METHANE IN BRINE AT 290°F (Haas)

SOLUBILITY OF METHANE IN BRINE @ 300 deg.F (CHAAS EQUATION)

Figure 33. SOLUBILITY OF METHANE IN BRINE AT 300°F (Haas)

setting, although sodium chloride has been the major component of the produced brines. Again, the combined effects of these other chemical constituents on gas saturation are also not well understood. Even with these uncertainties, it is believed that for the most part, the figures are representative of the expected levels of gas saturation in brine for given temperatures, pressures, and salinities.

One of the important questions that arises when producing fluids from geopressured aquifers is whether the gas content was under, at, or above the point of saturation in the brine. The question is further complicated by the chemical composition of the gas that is exsolved from the liquid phase. To this end, IGT, using the results from several DOE- and GRI-funded programs, updated the understanding on the degree of saturation of the Pleasant Bayou aquifer. This contract supported a portion of this analysis because of DOE's interest in the Pleasant Bayou #2 test and the implications that it had on computer simulation and economic projections. In addition, this work laid the groundwork for future analyses to determine the level of saturation for other geopressured aquifers being tested.

The report, "Do We Know Whether the Pleasant Bayou #2 is Saturated With Methane?" presented in Appendix E is the culmination of this latter effort. Although the report cannot state absolutely that the reservoir was at gas saturation, the conclusion is that the Pleasant Bayou #2 Well was producing 27 to 28 standard cubic feet of gas per stock tank barrel of brine (SCF/STB), which appears to be in the range of gas saturation for the formation. Because the separator was operating at an elevated pressure in excess of 800 psia during the sample collection period, about 5.4 SCF/STB of gas remained in solution and was disposed of.

However, to conclude whether the aquifer brine actually was saturated still requires:

- Determining whether the brine leaving the separator contained gas bubbles and, if so, quantifying their gas content in relation to brine volume.
- Laboratory recombination studies using separator gas and brine samples taken at separator pressure.
- Improved understanding of the extent to which observed CO₂ is actually in carbonate form before the brine is produced from the aquifer.

VISCOSITY OF FORMATION WATERS

After a careful review of our own work on brine viscosity, we concluded that the computer program developed by IGT gave answers consistent with values reported in the literature. The computer program developed made use of equations taken from "Viscosity of NaCl and Other Solutions Up to 350°C and 50 MPa Pressures" by S. L. Phillips, H. Ozbek, A. Igbene, and G. Litton, Lawrence Berkeley Labs, Nov. 1980 (LBL 11586, VC-66). The tables in Appendix F provide absolute viscosities in centipoise for sodium chloride solutions of 0 to 25 weight percent, from 150° to 350°F, and for 1,000 to 15,000 psi. Figures 34 to 48 graphically depict the data from the tables. All these data are reported in customary oil field units.

Another aspect of viscosity looked into was the possibility of an increase in the viscosity of brine when gas is in solution. Certain measurements taken during recombination studies for the Wells of Opportunity Program suggested that this may occur. However, upon further investigation, there appeared to be several reasons to suspect those reported values.

A modified rolling ball viscometer was used to make the viscosity measurements. The fluids used were separator brines that were saturated with formation gases. Measurements were made at formation temperatures and at pressures ranging from above the bubble point to about 1,000 psi.

Because measurements like these had never been made before, it was difficult to judge the validity of the results. However, on first inspection, the viscosity values obtained appeared to be high by about 50%. The reason we suspected the values were high is that at the lower pressures, where the fluids contained very little dissolved gas, we would expect the viscosity to approach the values for brines with no gas. At the lowest pressures, the measured viscosities were still 50% higher than would be expected. Very good values existed in the literature for brine viscosities of sodium chloride solutions to 4500 psi and 300°F (Kestin, 1978). In addition, we expected the presence of dissolved gas to lower the viscosities rather than raise them.

There were three possible sources of experimental difficulties, two that would produce artificially high values for viscosity and one that would result in either higher or lower values. These were—

- The rolling ball had not reached its terminal velocity when the timing device was turned on. This would mean longer roll times, and lower velocities, resulting in an apparently higher viscosity.

VISCOSITY OF BRINE SOLUTIONS @ 1000 psi

Figure 34. VISCOSITY OF BRINE SOLUTIONS AT 1000 psi

VISCOSITY OF BRINE SOLUTIONS @ 2000 psi

Figure 35. VISCOSITY OF BRINE SOLUTIONS AT 2000 psi

VISCOSITY OF BRINE SOLUTIONS @ 3000 psi

Figure 36. VISCOSITY OF BRINE SOLUTIONS AT 3000 psi

VISCOSITY OF BRINE SOLUTIONS @ 4000 psi

Figure 37. VISCOSITY OF BRINE SOLUTIONS AT 4000 psi

VISCOSITY OF BRINE SOLUTIONS @ 5000 psi

Figure 38. VISCOSITY OF BRINE SOLUTIONS AT 5000 psi

VISCOSITY OF BRINE SOLUTIONS @ 6000 psi

Figure 39. VISCOSITY OF BRINE SOLUTIONS AT 6000 psi

VISCOSITY OF BRINE SOLUTIONS @ 7000 psi

Figure 40. VISCOSITY OF BRINE SOLUTIONS AT 7000 psi

VISCOMITY OF BRINE SOLUTIONS @ 8000 psi

Figure 41. VISCOSITY OF BRINE SOLUTIONS AT 8000 psi

VISCOSITY OF BRINE SOLUTIONS @ 9000 psi

Figure 42. VISCOSITY OF BRINE SOLUTIONS AT 9000 psi

VISCOSITY OF BRINE SOLUTIONS @ 10,000 psi

Figure 43. VISCOSITY OF BRINE SOLUTIONS AT 10,000 psi

VISCOSITY OF BRINE SOLUTIONS @ 11,000 psi

Figure 44. VISCOSITY OF BRINE SOLUTIONS AT 11,000 psi

VISCOSITY OF BRINE SOLUTIONS @ 12,000 psi

Figure 45. VISCOSITY OF BRINE SOLUTIONS AT 12,000 psi

VISCOSITY OF BRINE SOLUTIONS @ 13,000 psi

Figure 46. VISCOSITY OF BRINE SOLUTIONS AT 13,000 psi

VISCOSITY OF BRINE SOLUTIONS @ 14,000 psi

Figure 47. VISCOSITY OF BRINE SOLUTIONS AT 14,000 psi

VISCOSITY OF BRINE SOLUTIONS @ 15,000 psi

Figure 48. VISCOSITY OF BRINE SOLUTIONS AT 15,000 psi

- The ball rolling in the fluid was in a turbulent rather than laminar flow regime. According to Hubbard and Brown (1943) this condition would produce an apparently higher viscosity. If the Reynolds number is not too high, they present a method for correcting the viscosity values.
- The calibration of the viscometer may not have been conducted at the temperature at which the actual measurements were to be made. The calibration factor for this instrument is geometry-dependent. The change in the ball and tube diameters with temperature changes this calibration factor. The viscosity in this case would appear either greater or smaller than the true value depending on the relative coefficients of thermal expansion of the ball and the tube. If the ball and the tube are of the same material, the calibration factor should increase with temperature. Using a calibration term obtained at a lower temperature would result in an apparently lower viscosity value.

These possible difficulties were brought to the attention of the laboratory that made the measurements. If any one or all of these possible difficulties were responsible for the higher viscosity values, there were relatively easy procedures for correcting the values without having to repeat the measurements. Of course the possibility existed that these corrections, when made, would not significantly affect the results. In that case the higher viscosities would have a significant influence on the results of reservoir analysis.

The following are references cited in the previous discussion:

- Kestin, J., et al., "Effect of Pressure on the Viscosity of Aqueous NaCl Solutions in the Temperature Range 20-150°C," J. Chem and Eng. Data 23, No. 4, 328 (1978).
- Hubbard, R. M. and Brown, G. G., "The Rolling Ball Viscometer," Ind. and Eng. Chem. Ana. Ed. 15, No. 3, 212 (1943).

Another reason for undertaking this review of viscosity is that in reservoir simulation, a number of parameters must be input to describe the formation and the fluids being produced. The basic equation in determining transmissibility is kh/μ where k is permeability, h is formation thickness, and μ is the viscosity. Given the large number of unknowns in a computer simulation, it is extremely helpful to minimize the number of "guesses" for parametric values. The tables in Appendix F and Figures 34 to 48 provide a reasonable approximation for brine viscosity under reservoir conditions.

RESERVOIR ENGINEERING STUDIES

As part of the independent assessments performed by IGT on reservoirs of interest to the DOE G² program, a number of first-order analyses were performed to determine expected flow rates on the Wells of Opportunity Program. Estimates of the reservoir sizes were also calculated, based on production data. These investigations were performed on the Wells of Opportunity and previously reported in monthly reports to DOE. Of particular significance was a detailed reservoir engineering study of the G. M. Koelemay No. 1 Well, which began producing commercial quantities of gas, natural gas liquids, and condensate while being tested as a DOE Well of Opportunity. The next section describes this unusual occurrence and the results of a numerical simulation of the reservoir.

RESERVOIR STUDY OF THE G. M. KOELEMAY WELL NO. 1

The G. M. Koelemay Well No. 1 proved to be a geopressured aquifer with a significant quantity of free gas and condensate. This occurrence of hydrocarbons in excess of those which were in solution prompted an analysis of the formation by numerical simulation. The following subsections provide an explanation of that study and the implications of the test results.

Capillary Pressure Data

Recognition of the fact that the G. M. Koelemay Well No. 1 had penetrated the formation below the gas cap, but was close enough to the gas zone to cone in the gas by substantially reducing the reservoir pressure near the well bore, led us to believe that the well had been completed in the transition zone. It was therefore believed that capillary pressure data, which are often neglected or greatly simplified, would be an important input into the numerical simulation. As a result, IGT personnel performed laboratory measurements on two Frio cores that were thought to be similar in nature to the Koelemay well.

The dry cores were weighed and the lengths and diameters measured. The cores were then placed in a vacuum jar that was evacuated for 1 hour. Next, the cores were saturated with a solution of 2% KCl and 2% NaCl by weight. The saturation weights were measured.

Basic data on the two cores tested are listed in Table 2. A rubber sleeve was placed around each core and a filter paper and semi-permeable membrane were put on the downstream end of the cores. The prepared plugs were placed inside a hydrostatic core holder configured for capillary pressure measurements. A confining pressure of 400 psi was applied around each rubber sleeve and core. The water level in each buret was marked as the zero point of 100% saturation after the cores stabilized. Pressure was applied to the upstream end of each core holder by using nitrogen gas. The pressure was increased in increments, with enough time between increases to allow the fluid level in the buret to stabilize for several hours. A reading of the water level for each pressure increment was taken. Detailed measurements for each core are shown in Tables 3 and 4. Saturation was calculated for each step by using the formula:

$$S_w = (\text{pore volume} - \text{cm}^3 \text{ of water out}) / \text{pore volume}$$

where S_w is the water saturation of the core.

Table 2. RELEVANT CORE DATA

	<u>Core Samples</u>	
	<u>Frio #17</u>	<u>Frio #82</u>
Porosity	27.5%	27.8%
Permeability	702 md	51 md
Length	3.6 cm	3.8 cm
Diameter	2.35 cm	2.40 cm
Core Volume	15.60 cm ³	17.18 cm ³
Dry Weight	30.7635 g	37.0426 g
Wet Weight	35.3370 g	41.7970 g

Table 3. CAPILLARY PRESSURE DATA — FRIO #17

<u>Date</u>	<u>Time</u>	<u>Room Temp., °C</u>	<u>Pore Pressure, psi</u>	<u>Water Out, cm³</u>	<u>S_w, Fraction</u>
7/24/81	1:45 p.m.	20.3	1.27	0.00	
	3:10 p.m.	20.3	1.24	0.16	
	4:40 p.m.	21.8	1.28	0.26	
7/27/81	9:00 a.m.	21.3	1.28	0.70	0.85
Pres- surized	9:30 a.m.	21.8	1.50		
	12:00 noon	21.6	1.49		
	3:00 p.m.	21.7	1.50	0.90	0.80
Pres- surized	4:10 p.m.	21.7	2.50		
7/28/81	9:00 a.m.	21.1	2.26	1.92	0.58
Pres- surized	12:00 noon	21.2	4.00		
7/28/81	4:30 p.m.	21.1	3.94	2.40	
	4:35 p.m.	21.1			
7/29/81	9:00 a.m.	21.2	4.18	2.64	0.42
	4:00 p.m.	22.0	3.95	2.66	
Pres- surized	4:40 p.m.	22.0	18.05		
7/30/81	9:00 a.m.	22.5	18.00	3.29	0.28
	3:00 p.m.	22.5	3.29		
7/31/81	9:00 a.m.	22.9	24.05	3.60	0.212
8/3/81	9:00 a.m.	22.5	24.10	4.12	0.0985
8/4/81	8:30 a.m.	22.5	24.10	4.14	0.0941

Table 4. CAPILLARY PRESSURE DATA — FRIO #82

<u>Date</u>	<u>Time</u>	<u>Temp., °C</u>	<u>Pore Pressure, psi</u>	<u>Water Out, cm³</u>	<u>S_w, Fraction</u>
7/17/81	3:00 p.m.	21.6	1.05	0.00	
	3:20 p.m.	21.6	2.01	0.00	
	4:00 p.m.	21.9	8.04	0.00	
7/20/81	8:45 a.m.	22.0	8.80	2.31	0.52
	3:18 p.m.	22.6	8.92	2.38	
	4:40 p.m.	22.8	8.90	2.40	
Pres- surized	4:40 p.m.	22.8	10.20		
7/21/81	8:45 a.m.	20.8	10.00	2.51	0.47
Pres- surized	10:02 a.m.	20.8	25.00		
	12:16 a.m.	20.7	25.20	2.58	
	3:30 p.m.	20.7	25.00	2.66	
	4:30 p.m.	20.7	25.10	2.66	
7/22/81	9:00 a.m.	20.2	24.75	2.88	0.39

Water saturation was plotted against pore pressure for each core as shown in Figure 49. As a cross-check against the laboratory results, J was calculated according to the semi-empirical relation identified by M. C. Leverett:

$$J = P_c (k/)^{1/2}$$

where J is a dimensionless function of the wetting phase saturation.

The J function of the cores for the same water saturation should be the same. The plot of J versus S_w in Figure 49 demonstrates the validity of the laboratory measurements.

Reservoir and Production Data

Reservoir characteristics were derived from the "Well of Opportunity" test performed during September 1981 with modifications based on the numerical simulation. Information on the relative permeability and fluid property inputs for the water and gas phases are presented in the appropriate following subsections.

IGT staff met with the Division Production Engineer of Lear Petroleum who had responsibility for the Koelemay well. Information on the well's performance was obtained, along with explanations for apparent variations from normal production. The information made available by Lear included—

- Daily production reports
- Well test surveys performed by Milton H. Cooke Co.
- Gas analyses
- Driller's log for the well
- Gas well status reports.

This information was used in a comparison with the projections that were made for the formation based on the extensive test data developed under the Wells of Opportunity Program. Because of intermittent production from the reservoir by the operator, a series of simplified and constant production predictions were made.

Reservoir Modeling

Working with INTERCOMP (also under contract to DOE), IGT personnel conducted a series of computer simulations to model pressure history. By

Figure 49. CAPILLARY PRESSURE CURVES

varying different reservoir parameters, the pressure history profiles were altered. Analysis of each run (which, until an adequate pressure profile for the initial drawdown test was achieved, was limited to only the first day) provided valuable insight into both the effect of the altered parameters on the simulation outcome and the sensitivity of the simulation to the magnitude of the change in the selected parameters.

Gas-water numerical reservoir simulation models available to the industry do not take into account the solution gas in the water. The only way to put the gas into the water is to use a three phase (black oil) model and assign the properties of water to the oil phase. This technique was employed for the simulation study of the G. M. Koelemay Well No. 1.

Background and Geology

The G. M. Koelemay Well No. 1 is located approximately 4 miles north of China, Texas, and 19 miles west of Beaumont, Texas. The well is in the Doyle Field area, which lies within several down-to-the-coast growth faults. The well is situated on the downthrow side of the southernmost fault and is separated from "tite" wells in the eastern sector by a splinter fault or other permeability barriers. The Leger sand is the reservoir of interest for the G. M. Koelemay Well No. 1. The sand is a member of the Mid-Eocene Yegua formation. Figure 50 shows the generalized structure map of the well. The cross section A-A' (Figure 51) shows the low angle and southern dip of the Yegua formation flattening out as it approaches the northern bounding fault. The gross thickness of the sand at the G. M. Koelemay Well No. 1 is 139 feet.

The G. M. Koelemay Well No. 1 was drilled by Lear Petroleum Exploration, Inc. After a short drill stem test and logging that indicated a water-bearing zone had been intercepted in the targeted formation, the Eaton Operating Company, Inc. (EOC) negotiated a production test as a DOE "Well of Opportunity." Lear abandoned the well as a dry hole and the EOC-IGT team tested the G. M. Koelemay Well No. 1 for methane production from a geopressured aquifer.

During the test of the well, substantial quantities of gas and oil coned into the well bore. This unusual occurrence of excess hydrocarbons from a geopressured aquifer led to an indepth numerical simulation study of the formation.

DOYLE FIELD AREA

JEFFERSON COUNTY, TEXAS

GENERALIZED STRUCTURE MAP

TOP MID-EOCENE

YEGUA "LEGER" SAND

CONTOUR INTERVAL = 50'

FAULT: STRIKE/DIP

DRY HOLE

Forest Oil Corp.
Kirby Lbr. Corp.

2 - 11,155'
T.D. 12,500'

A-43

A-475

A-803

HARDIN CO.

Tear Petr.
G.M. Koelemay

11,590'
T.D. 14,885'

A-60

A-11

A-287

JEFFERSON CO.

A-550

A-743

A-744

A-824

A-444

A-237

A-107

A'

A-106 - 11,750'

A-25

A-16

Figure 50. GENERALIZED STRUCTURE MAP

Figure 51. YEGUA "LEGER" SAND CROSS-SECTION

Rock Properties

The rock properties for the reservoir were obtained from well logs and well testing. They are represented in Table 5.

Table 5. ROCK PROPERTIES

Porosity	= 0.20
Horizontal permeability	= 0.35 md
Producing thickness (net)	= 77 ft
Rock compressibility	= 0.000003 psi ⁻¹
Reservoir temperature	= 260°F
Original gas-water contact	= 11,600 ft
Depth to top of perforation	= 11,683 ft
Reservoir radius	= 3,000 ft

Relative Permeability

The relative permeability values for the gas-oil system are depicted in Table 6. Capillary pressure values determined in the laboratory were not utilized because the permeability of the matrix rock was determined to be significantly less than that of those used in the experiment. This assessment of low permeability came about after several computer simulations and careful analysis of the pressure data indicated the probable existence of natural fractures at or near the well bore.

Table 6. RELATIVE PERMEABILITY

<u>S_L</u>	<u>k_{rw}</u>	<u>k_{rg}</u>
0.01	0.0	0.335
0.10	0.02	0.30
0.20	0.06	0.25
0.40	0.21	0.16
0.50	0.31	0.11
0.70	0.56	0.05
0.90	0.86	0.01
0.95	0.94	0.004
0.995	0.98	0.00
1.00	1.00	0.00

where S_L = total liquid saturation

k_{rw} = relative permeability to water phase

k_{rg} = relative permeability to gas phase

Fluid Properties

For the most part fluid properties were measured analytically during the test period. Those that were not were calculated using empirical correlations. Table 7 presents the fluid properties used.

Table 7. FLUID PROPERTIES

Water formation volume factor	= 1.0421 RB/STB
Water density	= 63.68 lbs/ft ³
Average water viscosity	= 0.244 cp
Water compressibility	= 0.0000036 psi ⁻¹
Gas gravity	= 0.72
Initial reservoir pressure	= 9420 psia @ 11,600 ft

The PVT properties for gas and water required for the simulation are presented in Tables 8 and 9.

Simulation Model

Intercomp's Beta II model was used for this study. It is a three-dimensional, three-phase model that can represent all types of reservoir heterogeneity.

A radial geometry was used to define the areal extent of the reservoir. The area of interest is depicted by a total of 63 grid blocks. This includes nine blocks in the radial direction, one in the theta direction, and seven layers in the vertical direction. The well block is 0.5 foot long, and the rest of the block sizes in the radial direction are calculated internally by logarithmic radial spacing.

In the vertical direction, it was necessary to take seven layers in order to obtain a good simulation of the coning effects. The thickness of the layers starting at the top (Layer 1) were: 10, 30, 30, 13, 38, 39, and 80 feet. The top of the first layer is at 11,600 feet. The well was perforated in Layers 5 and 6 only.

History Match

Field testing of this well was started on September 12, 1980, and lasted for a period of 13.46 days. The history match was done to cover this entire period.

The history match was made by matching the bottomhole pressure and the gas production rates. Brine production rates were input into the simulator.

Table 8. GAS PVT DATA

<u>Pressure, psia</u>	<u>Formation Factor, RB/MCF</u>	<u>Gas Viscosity, cP</u>
2,000	1.578	0.016
4,000	0.766	0.021
6,000	0.556	0.025
8,000	0.448	0.030
10,000	0.311	0.035
12,000	0.167	0.041

Table 9. WATER PVT DATA

<u>Pressure, psia</u>	<u>Solution GWR, SCF/STB</u>	<u>Water Viscosity, cP</u>	<u>Formation Factor, RB/STB</u>
2,000	30	0.365	1.061
4,000	31	0.368	1.055
6,000	32	0.372	1.058
8,000	33	0.378	1.042
10,000	34	0.386	1.036
12,000	35	0.395	1.030

During the history match it was observed that several parameters had a profound effect on the pressure profile and gas production. The reservoir permeability and the near well-bore transmissibilities, in particular, had a great deal of impact on the calculated pressures. In addition, the critical gas saturation had an important effect on gas production. Lower critical gas saturations gave a better fit with the observed data.

An examination of the pressure test analyses indicated the possibility of a naturally fractured formation near the well bore. This was consistent with the experience of the initial computer simulations. As such, the transmissibility around the well bore was increased considerably.

The performance summary of the well during history match is tabulated in Table 10. Figure 52 shows the brine production rate that is input to the simulator.

Figures 53, 54, and 55 illustrate the history matches for bottomhole pressure, gas production rate, and gas-brine ratio, respectively. As noted in these figures, it was difficult to get an exact match of the gas breakthrough during the third drawdown, but the overall trend appears to be a good fit. Figure 56 shows the cumulative brine production for the well during the history match.

Predictions

Three prediction runs were made to determine the future potential of the well to produce gas by producing large quantities of brine.

At a brine production rate of 3000 BPD, the well sustained that level of production for only 45 days. At 2000 BPD, the well was able to produce that amount for 4 years. Table 11 shows the reservoir performance summary for the 2000 BPD case. Table 12 shows the 1000 BPD case, in which the well sustained production for at least 15 years.

With the well producing 2000 BPD of brine for 4 years, a total of 1.3 BCF of gas was produced along with 2,925 MSTB of brine. For the 1000 BPD case, a total of 2.6 BCF of gas and 5,493 MSTB of brine was produced over 15 years. In both cases the gas-water ratio stayed constant at about 450 SCF/STB. Figures 57 to 61 illustrate the predicted reservoir performance for the 1000 BPD and 2000 BPD cases for bottomhole pressure, gas production rate, gas-water ratio, cumulative gas production, and cumulative brine production, respectively.

Table 10. PERFORMANCE SUMMARY OF THE G. M. KOELEMAY WELL NO. 1

PERFORMANCE SUMMARY FOR G.M.KOELEMAY WELL NO.1 HISTORY MATCH						
TIME	GAS PRCD RATE	WTR PRCD RATE	CUM GAS PROD	CUM WTR PROD	GAS-WTR RATIO	BOT HOLE PRESSURE
DAYS	MCF/DAY	STB/DAY	MMCF	MSTB	SCF/STB	PSIA
0.30	80.	2448.	0.	1.	33.	7782.
0.62	76.	2334.	0.	1.	33.	7531.
1.05	73.	2240.	0.	2.	33.	7331.
1.50	0.	0.	0.	2.	33.	8799.
2.50	0.	0.	0.	2.	34.	9117.
4.20	0.	0.	0.	2.	34.	9273.
4.37	151.	4658.	0.	3.	32.	6738.
4.63	139.	4335.	0.	4.	32.	6181.
5.00	0.	0.	0.	4.	33.	8558.
6.04	0.	0.	0.	4.	33.	9012.
6.08	221.	6808.	0.	5.	32.	6965.
6.12	198.	6148.	0.	5.	32.	6541.
6.17	179.	5564.	0.	5.	32.	6253.
6.21	163.	5092.	0.	5.	32.	6148.
6.25	155.	4852.	0.	6.	32.	6069.
6.29	147.	4596.	0.	6.	32.	6036.
6.38	139.	4336.	0.	6.	32.	5982.
6.46	133.	4160.	0.	6.	32.	5945.
6.58	138.	4324.	0.	7.	32.	5754.
6.67	134.	4220.	0.	7.	32.	5676.
6.88	127.	4000.	0.	8.	32.	5574.
7.08	124.	3872.	0.	9.	32.	5498.
7.42	117.	3652.	0.	10.	32.	5435.
7.52	122.	3500.	0.	12.	35.	5368.
8.79	146.	3172.	1.	15.	46.	5419.
9.80	244.	3372.	1.	18.	72.	5101.
11.00	415.	3372.	1.	22.	123.	4874.
11.80	549.	3372.	2.	25.	163.	4718.
12.54	705.	3372.	2.	27.	209.	4563.
13.46	835.	3208.	3.	30.	260.	4507.

BRINE PRODUCTION RATE FOR G.M.KOELEMAY #1

Figure 52. BRINE PRODUCTION RATE FOR G. M. KOELEMAY WELL NO. 1

PRESSURE HISTORY MATCH FOR G.M.KOELEMAY #1

Figure 53. BOTTOMHOLE PRESSURE HISTORY FOR G. M. KOELEMAY WELL NO. 1

GAS PRODUCTION RATE MATCH FOR G.M.KOELEMAY #1

Figure 54. GAS PRODUCTION RATE HISTORY MATCH FOR G. M. KOELEMAY WELL NO. 1

GAS-BRINE RATIO HISTORY MATCH FOR G.M.KOELEMAY #1

Figure 55. GAS-BRINE RATIO HISTORY MATCH FOR G. M. KOELEMAY WELL NO. 1

CUM. BRINE PRODUCTION, mstb

CUMULATIVE BRINE PRODUCTION HISTORY MATCH FOR G.M.KOELEMAY #1

Figure 56. CUMULATIVE BRINE PRODUCTION FOR G. M. KOELEMAY WELL NO. 1

Table 11. PREDICTED RESERVOIR PERFORMANCE SUMMARY AT 2000 BPD

PERFORMANCE SUMMARY FOR G.M.KOELEMAY WELL NO.1						
PREDICTION CASE FOR 2000 BWPB						
TIME	GAS PRCD RATE	WTR PRCD RATE	CUM GAS PRCD	CUM WTR PROD	GAS-WTR RATIO	BOT HOLE PRESSURE
DAYS	MCF/DAY	STB/DAY	MMCF	MSTB	SCF/STB	PSIA
45.00	875.	2000.	25.	93.	437.	5048.
90.00	873.	2000.	68.	183.	436.	5476.
182.00	877.	2000.	149.	367.	439.	4073.
275.00	897.	2000.	312.	733.	448.	3568.
360.00	922.	2000.	644.	1463.	461.	3014.
448.00	937.	2000.	984.	2193.	469.	2646.
541.00	941.	2000.	1328.	2925.	470.	2352.

Table 12. PREDICTED RESERVOIR PERFORMANCE SUMMARY AT 1000 BPD

PERFORMANCE SUMMARY FOR G.M.KOELEMAY WELL NO.1						
PREDICTION CASE FOR 1000 BWPC						
=====						
TIME	GAS PROD RATE	WTR PROD RATE	CUM GAS PROD	CUM WTR PROD	GAS-WTR RATIO	BOT HOLE PRESSURE
-----	-----	-----	-----	-----	-----	-----
DAYS	MCF/DAY	STB/DAY	MMCF	MSTB	SCF/STB	PSIA
-----	-----	-----	-----	-----	-----	-----
45.00	349.	1000.	13.	62.	349.	7104.
90.00	420.	1000.	32.	107.	420.	6970.
180.00	428.	1000.	71.	199.	428.	6755.
270.00	434.	1000.	150.	382.	434.	6518.
360.00	447.	1000.	311.	747.	447.	6256.
450.00	457.	1000.	476.	1112.	457.	6082.
540.00	464.	1000.	645.	1478.	464.	5933.
630.00	469.	1000.	815.	1843.	469.	5793.
720.00	473.	1000.	987.	2208.	473.	5655.
810.00	476.	1000.	1161.	2573.	476.	5518.
900.00	479.	1000.	1335.	2938.	479.	5380.
990.00	481.	1000.	1510.	3303.	481.	5248.
1080.00	483.	1000.	1686.	3668.	483.	5113.
1170.00	486.	1000.	1863.	4033.	486.	4979.
1260.00	487.	1000.	2041.	4398.	487.	4845.
1350.00	488.	1000.	2219.	4763.	488.	4716.
1440.00	489.	1000.	2397.	5128.	489.	4590.
1530.00	491.	1000.	2576.	5493.	491.	4467.

PREDICTED BOTTOM-HOLE PRESSURE FOR G.M.KOELEMAY #1

Figure 57. PREDICTED BOTTOMHOLE PRESSURE FOR G. M. KOELEMAY WELL NO. 1

PREDICTED GAS PRODUCTION RATE FOR G.M.KOELEMAY #1

Figure 58. PREDICTED GAS PRODUCTION RATE FOR G. M. KOELEMAY WELL NO. 1

Figure 59. PREDICTED GAS-BRINE RATIO FOR G. M. KOELEMAY WELL NO. 1

PREDICTED CUMULATIVE GAS PRODUCTION FOR G.M.KOELEMAY #1

Figure 60. PREDICTED CUMULATIVE GAS PRODUCTION FOR G. M. KOELEMAY WELL NO. 1

PREDICTED CUMULATIVE BRINE PRODUCTION FOR G.M.KOELEMAY #1

Figure 61. PREDICTED CUMULATIVE BRINE PRODUCTION FOR G. M. KOELEMAY WELL NO. 1

Implications of the G. M. Koelemay Well No. 1

In the Gulf Coast, millions of years of sedimentary accumulation have been accompanied by the occurrence of a sequence of subsurface faults. In many areas these faults have isolated sandstone bodies from permeable connections to the surface.

At depths below about 10,000 feet, these isolated sandstone bodies are geopressured. That is, the fluid pressure in the sandstone pores is higher than the pressure that would exist from a continuous column of reservoir brine to the surface. The high fluid pressure is produced by liberation of water of hydration and the generation of natural gas in adjacent and deeper shales. An upper limit on fluid pressure is provided by leakage up fault planes when fluid pressure approaches the weight of the overlying rock.

The relative amounts of total brine and total natural gas in individual sandstone bodies varies widely because of variations in the independent processes of dehydration of clays, generation of natural gas, and vertical transport in fault planes. If the total quantity of natural gas in a sandstone body exceeds the amount soluble in the total brine content of the sandstone, gravity separation provides the layering.

In the "gas cap" portion of the sandstone body, surface tension maintains a film of water on the surfaces of the sand grains and cementing material, but the continuous mobile phase is gas. The amount of gas in place is about 100 SCF/ft³ of reservoir rock. This mobile gaseous phase includes water vapor at the partial pressure determined by the temperature of 250° to 300° F.

In the aquifer portion of the sandstone body, however, the mobile fluid phase is brine with natural gas in solution. The amount of solution gas present is about 1.0 SCF/ft³ of reservoir rock.

In the transition zone, both mobile gas and mobile brine phases are present. The relative amounts at each depth are determined by the capillary pressure rise of water in the pores between sand grains and, therefore, the size distribution of those pores. In a very high permeability reservoir, such as 100 to 1000 millidarcies, capillary forces may provide a transition zone only a foot or so thick. For pore sizes small enough for permeability to be only about 1 millidarcy, however, the transition zone thickness may be tens of feet.

Historically, the geopressured target of the gas industry in the Gulf Coast has been the high-pressure gas caps of the sandstone bodies. If brief production testing revealed predominantly brine production, the well was abandoned as a "dry hole." As fluid pressure in a sandstone body is reduced by gas production from "successful" wells, the compressibility of brine and reservoir rock causes upward movement of the top of the transition zone. When this upward movement results in operating costs (including that of brine disposal) in excess of revenue from gas sales, the producing interval is abandoned.

In contrast to the industry target of production from "gas caps," the DOE G² program has evaluated energy production from geopressured aquifers that are not accompanied by gas caps or by transition zones within the same isolated sandstone body.

The Wells of Opportunity were all at locations where private industry assessment of geological and geophysical data revealed sufficient likelihood of a "gas cap" for expenditure of roughly a million dollars of risk capital to be judged worthwhile. To the extent that such exploratory wells are "near misses," the gas caps that actually exist become undiscoverable. This is because the public information on the "dry hole" will weigh heavily upon any future investment decisions for additional drilling at that prospect location.

Discovery of gas in excess of solubility in reservoir brine was an exciting byproduct of the production tests during the Wells of Opportunity program. On one of these tests (G. M. Koelemay Well No. 1), the horizontal pressure gradient from brine production resulted in coning of gas down to a well that penetrated the sandstone in the aquifer or transition region. This well was placed in commercial production.

Figures 52, 53, and 55 show the brine production rate, bottomhole pressure, and produced gas-brine ratio for the G. M. Koelemay Well No. 1 for the test period. The most striking feature of these data is the monotonic increase in the gas/brine ratio from 31 to more than 37 SCF/STB during the first flow test. Produced gas/brine ratios during the second flow test and during the first several hours of the third flow test remained constant at about 37 SCF/STB. Two additional striking features of the first 7 days of data are: 1) the high (and increasing) natural gas liquids (NGL) content of flare-line gas during the first flow test, and 2) detection of produced oil in brine samples.

Gas samples collected after bottoms-up on the first test of this well had an NGL content of about 1.6 gal/MCF. About 2.4 gal/MCF was observed on gas samples collected during the second flow test and during the first few hours of the third flow test.

Data from Figures 52, 53, and 55 for the next 7 days show the producing characteristics for the remainder of the DOE test of this well. At the end of the test when the well was returned to the original operator, production from the 205°F separator consisted of —

- 1000 MCF/day of dry natural gas (including NGL) to the flare line
- 137 bbl/day of ethane and heavier hydrocarbons to the flare line
- About 75 bbl/day of oil to a tank
- 3150 STB/day of brine, with a gas content of 3.1 SCF/STB, to the disposal well.

The above estimate of hydrocarbon production is not complete because of the loss of volatile hydrocarbons from the high-temperature oil produced to the stock tank.

Eighteen months after this test, the well was still a commercial hydrocarbon producer. Thus, there is little doubt that the well was a "near miss" in the context of exploration for a gas cap. Further, the careful measurement of the first day's variations in produced gas/brine ratio plus variations in relative abundances of hydrocarbon species may well demonstrate a valuable tool for early detection of close proximity of a gas cap to the well.

This test illustrates conditions under which brine production testing may well be a viable exploration tool. The following characteristics of the well were judged particularly relevant:

- The reservoir was sufficiently geopressured for initial shut-in pressure on a brine-filled well bore to be more than 2500 psi.
- Sandstone thickness and permeability were such that a production rate of a few thousand barrels per day provided more than 1000 psi of drawdown of bottomhole pressure.

Recognition of these characteristics is important in the context of testing costs. For the G. M. Koelemay Well No. 1, clear indications of gas in excess of solubility in reservoir brine were observed by the time that

cumulative production had reached a few thousand barrels. This quantity of brine can be disposed of at modest cost. But if the product of permeability times thickness were much greater, then drawdown sufficient to detect excess gas would require much higher flow rates and longer test times. Testing cost would be much higher if hundreds of thousands or millions of barrels of brine had to be produced.

Definitive onsite data collection and interpretation are an essential part of testing with costs low enough to be commercially viable. These should include —

- Brine analysis such that expected gas solubility in brine, corrected for salinity effects, can be promptly defined.
- Onsite gas analysis to provide the composition data essential to accurately interpret orifice meter data.
- Real-time determination of gas and brine production rates with a time resolution of 1/2 hour or less.
- Computational procedures that include — 1) correction of measured gas flow for water vapor passing through the orifice meter, 2) addition of gas remaining in solution in brine from the separator to gas observed from the separator and 3) correction of measured brine flow rates for temperature and pressure at the turbine meter.

The overall accuracy of onsite data collection and interpretation should be sufficient to provide resolution of better than 1 SCF/STB of brine. With such resolution, the data from DOE's Wells of Opportunity Program suggest that less than 24 hours of brine production with bottomhole pressure drawdown in excess of 1000 psi may well indicate whether a free gas phase exists in close proximity to the well bore. If these initial results are encouraging, additional testing will be required to define commercial potential.

More detailed information concerning the above can be obtained from the paper "Brine Production as an Exploration Tool for Water Drive Gas Reservoirs," presented at the 17th Intersociety Energy Conversion Engineering Conference held in Los Angeles, California, August 8-13, 1982.

APPENDIX A.

Methane Production From Geopressured Aquifers
Journal of Petroleum Technology
July 1982

Methane Production From Geopressured Aquifers

M.G. Doherty, SPE, Inst. of Gas Technology
P.L. Randolph, SPE, Inst. of Gas Technology
L.A. Rogers,* SPE, Inst. of Gas Technology
N.A. Poonawala, SPE, Inst. of Gas Technology

Summary

Several assessments of geopressured aquifers have been performed during the past several years. This paper re-examines an earlier SPE publication¹ in light of data available from recent research and geopressured aquifer well tests. What has been learned about geopressured aquifers in terms of reservoir parameters is incorporated to narrow the ranges of uncertainty in conducting parametric studies to predict production of natural gas. Economic sensitivity of the reservoir parameters is studied in terms of a reassessment of the capital investment and operating costs in constant (1980) dollars required for a complete geopressured aquifer production system. Test data from the U.S. DOE geopressured/geothermal well, Pleasant Bayou Well 2, are used in the analysis.

Introduction

A few years ago, Randolph¹ examined the potential for natural gas production from U.S. gulf coast geopressured aquifers. Since that time, a number of encouraging as well as discouraging findings have narrowed the ranges of uncertainty for some parameters. In other cases, more questions have been raised as a result of the information compiled.

An interesting metamorphosis has taken place concerning emphasis of the public domain program under the sponsorship of the U.S. DOE. Early in the program history, brine production from geopressured aquifers was considered primarily for electricity generation through the hydraulic and thermal energy produced. This sentiment gradually changed to an emphasis on the production of the methane dissolved in the brine. Now another change is occurring. With the realization that one important cost factor of the produced methane involves brine disposal, utilization of the hydraulic and thermal potential to help reduce reinjection costs is being reconsidered. In addition, using the pressure and the heat produced to reinject fluids into the original aquifer for higher recovery of brine and methane through pressure

maintenance is under consideration. However, the current thrust is aimed at gas production while examining ways to reduce expenses and/or increase revenues.

A positive regulatory action deregulated geopressured aquifers along with some other unconventional gas sources. But the question is: "Can the market bear a price sufficiently high to encourage development of geopressured aquifers in general?"

In the past, interviews with individuals experienced in natural gas exploration in geopressured areas revealed a pessimistic view on methane production from geopressured aquifers. Recent interactions indicate a slight moderation of this earlier appraisal—interest, or perhaps curiosity, on the part of the private sector seems to be increasing, judging from attendance at periodical U.S. DOE/industry geopressured-geothermal forum meetings—but negative and cautious opinions prevail.

Computational Procedures

When examining the cost significance of various parameters, computational procedures need to be defined carefully. An extension of the reservoir engineering techniques published by Bernard² for a bounded circular aquifer as discussed in Ref. 1 and modified for use in IGT's one-dimensional, single-phase reservoir simulator are used. Economic assessments are based on a standard discounted cash flow (DCF) analysis^{3,5} with constant 1980 dollars to eliminate the effect of inflation. The Appendix provides details on the computational procedures.

Base Case

A substantial amount of work resulted in characterizing the geopressured and geothermal resource and defining reservoir parameters in Louisiana^{6,7} and Texas.⁸⁻¹¹ Reviews of the geopressured aquifer resource^{12,13} and data from geopressured/geothermal test wells have been published.¹⁴⁻¹⁷ Already, some interpretations of these data are leading to differing conclusions.^{18,19}

Extensive studies also have been conducted on the environmental and socioeconomic aspects²⁰⁻²⁶ of geopressured/geothermal development around the gulf coast area. The results of these studies suggest that

*Now with Gas Research Inst.

TABLE 1—BASE CASE

Reservoir Properties	Previous Base Case	New Base Case
Depth d , ft (m)	13,000 (3962)	14,680 (4474)
Thickness h , ft (m)*	162 (49)	120 (37)
Area, sq miles (km ²)	44 (114)	25.4 (65.8)
Radius of equivalent circular reservoir r_e , ft (m)	19,760 (6023)	15,000 (4572)
Porosity ϕ , fraction	0.216	0.176
Permeability k , md	18	150
Compression drive C_e , psi ⁻¹ (mPa ⁻¹)	1.112×10^{-5} (1.61×10^{-3})	4.0×10^{-6} (0.58×10^{-3})
Pressure p_i , psi (MPa)	11,000 (75.8)	11,235 (77.5)
Gas saturation, scf/bbl (std m ³ /m ³)	44.1 (7.9)	25 (4.5)
Viscosity of fluid μ , cp (Pa·s)	0.199 (0.199)	0.2 (0.0002)
Well Characteristics		
Wellbore radius r_w , ft (m)	0.275 (0.08)	0.3 (0.09)
Production casing size, in. (mm)	5.5 OD, 4.67 ID (139.7 OD, 118.6 ID)	5.5 OD, 4.54 ID (139.7 OD, 115.3 ID)
Friction drop p_f , psi (kPa)	$7.477 \times 10^{-11} dq^2$ ($51.552 \times 10^{-11} dq^2$)	**
Hydraulic head p_h , psi (kPa)	0.465 d (3.206 d)	0.465 d (3.206 d)
Production rate q , B/D (m ³ /d)	$\leq 40,000$ (≤ 6359)	30,000 (4770)
Wellhead pressure (minimum) p_s , psi (kPa)	500 (3447)	500 (3447)

*Sixty feet (18.3 m) currently perforated, but a similar 60-ft (18.3-m) zone underlies the producing formation.

**Based on subroutine that calculates friction drop for single-phase flow through pipe.

adherence to standard industry practices for brine disposal as regulated by law should minimize any waste-disposal problems. The possibility of subsidence has been identified as a potential problem; however, there is no consensus on how greatly subsidence may affect surface conditions when producing from a geopressed aquifer. No unusual environmental impacts are anticipated that have not been studied carefully and understood as the result of significant oil and gas production in the gulf coast area.

These considerations have led to base-case reservoir properties derived primarily from the U.S. DOE's Brazoria County geopressed/geothermal test well, Pleasant Bayou Well 2. Table 1 gives reservoir properties and well characteristics, contrasting the new base case with that in Ref. 1.

Table 2 details the new base-case economic assumptions. The appropriate choice of capital investment costs is based on the maximum initial flow rate selected for production regardless of how long the well can sustain that flow. Lease acquisition costs are rolled into the figures, but there is no adjustment for dry hole costs.

Economic Sensitivity of Reservoir Parameters

Several reservoir parameters are important for economic analysis of geopressed aquifers. By varying each characteristic over a range judged credible by recent field experiences and laboratory research, a determination of the sensitivity of each of the reservoir characteristics is obtained.

TABLE 2—BASE-CASE ECONOMIC ASSUMPTIONS

	Maximum Producing Capacity (\$1,000)		
	20,000 B/D (3180 m ³ /d)	30,000 B/D (4770 m ³ /d)	40,000 B/D (6360 m ³ /d)
Production well*			
tangible	685	685	685
intangible	1,815	1,815	1,815
Surface facilities			
tangible	1,620	1,750	1,869
intangible	1,325	1,435	1,538
Disposal wells**			
tangible	201	268	331
intangible	594	792	994
Totals			
tangible	2,506	2,703	2,885
intangible	3,733	4,042	4,347
Total cost	6,239	6,745	7,232
Operating expenses			
fixed	\$320,000/yr		
variable	\$0.03/bbl (\$0.19/m ³)		
Taxes, %			
effective tax rate	48		
severance tax	8		
investment tax credit	20		
Depletion Allowance, %	10		
Royalty, %	12.5		

*Well of 14,700 ft (4481 m) total depth at \$170/ft (\$558/m) includes completion and Christmas tree.

**Shallow disposal well (~4 500 ft or ~1372 m) at an average cost of \$265,000. Disposal well capacity is 10,000 B/D (1590 m³/d), and one backup well is required.

Fig. 1—Gas price as a function of GWR.

Gas/Water Ratio

One of the most critical reservoir parameters is the gas/water ratio (GWR). Early estimates of gas content assumed much lower salinities than actually encountered during the first field tests. For example, the reservoir produced at the Brazoria test site had an initial pressure of 11,235 psi (77.5 MPa) at 301°F (149°C) with a total salinity of 125,000 to 130,000 ppm. The GWR measured during early tests was about 25 scf/bbl (4.5 std m^3/m^3). Total salinities of about half the amount actually found were anticipated, thereby significantly decreasing the originally estimated GWR.

This salinity problem also bears on two related concerns. First, many researchers have tackled the question of methane solubility.^{27-31*} However, enough variation exists among results for given temperatures, pressures, and salinities that there remains an important question about what constitutes a saturated solution.

This problem bears heavily on the second point. Understanding methane solubility in brine enables predictions about excess gas existing in a dispersed, immobile gas phase or as free gas in a gas cap. The existence of excess gas greatly improves recovery economics. On the other hand, knowing that the brine is undersaturated allows us to determine economics based strictly on solution gas production.

Because of the marginal economics of geopressed aquifers, narrowing the uncertainty about methane solubility is critical to any assessment of the viability of this potential resource. Fig. 1 shows the wellhead prices of gas required for a 15% internal rate of return (IRR) after taxes for the base case, varying only the average GWR from 15 to 45 scf/bbl (2.7 to 8.1 std m^3/m^3). The results indicate that (as might be expected) gas prices are nearly inversely proportional to GWR's—declining from a high of \$29.01/Mcf to \$7.29/Mcf (\$1.02/ m^3 to \$0.28/ m^3).

Because of salinity's adverse effect on methane solubility, the DOE's geopressed/geothermal "Wells of Opportunity Program" site-selection process has been modified. Greater emphasis has been placed on seeking much less saline aquifers ($\leq 70,000$ ppm) in an attempt

Fig. 2—Production histories, varying external reservoir radius.

to locate test sites with higher GWR's.

Radius

The effect of fault block area on calculated production histories and wellhead cost of gas is an important factor. There has been much debate over the real extent of fault blocks. Individuals experienced in exploration for and production of geopressed gulf coast natural gas reservoirs consistently have stated that fault block areas were smaller than the 44 sq miles (114 km^2) assumed in Ref. 1. Yet tests on Pleasant Bayou Well 2 indicate that a radius of 15,000 ft (4527 m) has been reached, and the reservoir limits have not been found. Thus, the base-case external radius of 15,000 ft (4527 m) has been increased to 20,000 and 25,000 ft (6096 and 7620 m) for areas of 45.1 and 70.4 sq miles (117 and 182 km^2) to study the effect of this parameter. Fig. 2 illustrates the possible production histories by varying r_e .

While a 70 sq mile (182 km^2) area is rather optimistic, further testing of the Pleasant Bayou Well 2 will provide more definitive data on reservoir limits. However, according to the production histories of these simulations, wellhead gas prices range from \$15.36 to \$10.09/Mcf (\$0.54 to \$0.36/ m^3) for the 25,000-ft (7620-m) external radius. A 20,000-ft (6096-m) r_e reduced the wellhead gas price to \$11.87/Mcf (\$0.42/ m^3) from the base-case figure.

Compression Drive

A highly debatable reservoir parameter is the compression drive coefficient, C_e , which is defined in this paper as the fractional change in volume of pores per pound per square inch of pore-pressure change. This single coefficient describes the combined effects of water compression, rock matrix compression, and formation compaction.

The compression coefficient for water is well known, approximately 3×10^{-6} psi $^{-1}$ (4.35×10^{-4} MPa $^{-1}$). However, this value could be higher as a result of gas in solution.

Until recently, few data existed concerning the compression coefficient for the matrix rock or compaction coefficient for geopressed aquifers. As a result, judgment by other authors usually spanned a range of about 10×10^{-6} to 62.3×10^{-6} psi $^{-1}$ (1.45×10^{-3} to

*Johnson, A.E.: "The Correlation of Methane-Brine Solubility Data," unpublished paper, available from Louisiana State U. Office of Energy Programs, Baton Rouge (March 1980).

Fig. 3—Production histories, varying rock PV compressibility.

$9.04 \times 10^{-3} \text{ MPa}^{-1}$) for C_e , reflecting the contribution of water and rock matrix compression and formation compaction. However, tests by Gray *et al.*³² revealed that the contribution of rock matrix compression and formation compaction for cores from the Pleasant Bayou Well 2 is less than $1 \times 10^{-6} \text{ psi}^{-1}$ ($1.45 \times 10^{-4} \text{ MPa}^{-1}$)—significantly smaller than previously thought. The relatively low value is reflected in the range of 3.5×10^{-6} to $5.5 \times 10^{-6} \text{ psi}^{-1}$ (5.08×10^{-4} to $7.98 \times 10^{-4} \text{ MPa}^{-1}$) for C_e or 0.5×10^{-6} to $2.5 \times 10^{-6} \text{ psi}^{-1}$ (7.25×10^{-5} to $3.63 \times 10^{-4} \text{ MPa}^{-1}$) for the contribution of the rock matrix and formation compaction factors selected for this parametric study. The effect of C_e is shown clearly in Fig. 3. The impact on the wellhead price of gas decreases the cost from \$16.50 to \$13.14/Mcf (\$0.58 to \$0.46/m³) for the greatest value of the compression drive coefficient.

Another consideration for the appropriate values for C_e is the possible contribution of shale dewatering to the compression drive. There are no data yet on the effect of shale dewatering. However, the joint U.S. DOE/Dow Chemical Parperdue geopressured/geothermal research well in Louisiana offers an opportunity to test and to measure potential contribution of shale dewatering to the formation drive mechanism.

Reservoir Thickness

The effect on production of varying reservoir thickness from the base-case value of 120 ft (37 m) is shown in Fig. 4. The impact on the wellhead price of the gas is to decrease the gas price from a high of \$24.34/Mcf (\$0.86/m³) for the 60-ft (18-m) case to \$9.42/Mcf (\$0.33/m³) for the 400-ft (122-m) case. As the formation thickness increases, the wellhead price of gas becomes less sensitive to the changes. This apparently results from the production limitation of 30,000 B/D (4770 m³/d). For this parameter, the gas price is somewhat production-limited. From a DCF perspective, higher production rates early in a project life add to the cash flow when the dollars are “worth” more. However, the increased capital investment required for additional equipment and disposal wells tends to offset some gains of the higher flow rates. A detailed discussion of the impact of initial production rates follows.

Fig. 4—Production histories, varying pay zone thickness.

Previously referenced studies characterizing the geopressured aquifer resources around the gulf coast areas of Louisiana and Texas assure that there are ample prospective sands greater than 100 ft (30.5 m) thick. The major concern reverts to the previously discussed question of the areal extent of the fault blocks. Thus, the volume of the geopressured aquifers must be taken into consideration. In the case of the Pleasant Bayou test well, the thickness of the sands is known, but the areal extent has not yet been determined.

With the base-case external radius of 15,000 ft (4572 m) and the four reservoir thicknesses, a volumetric calculation provides the gas price ranging from \$24.34 to \$9.42/Mcf (\$0.86 to \$0.33/m³) found in Table 3. Recall that gas prices for the larger volumes are affected adversely by the production rate used in the study. Nevertheless, the volume of the sands is important when examining a prospective geopressured aquifer.

Reservoir Pressure

Reservoir pressures encountered in the geopressured regions vary widely, ranging up to a pressure gradient of 1 psi/ft (22.6 kPa/m). The Pleasant Bayou Well 2 had an initial pressure gradient of 0.77 psi/ft (17.4 kPa/m). Because of this variability, we examined the effect of initial reservoir pressures on wellhead gas prices. The results of the parametric study are shown in Fig. 5. By increasing the initial reservoir pressure to 13,210 psi or 0.9 psi/ft (91 MPa or 20.4 kPa/m), the calculated wellhead price of gas decreases to \$12.42/Mcf (\$0.44/m³). A lower pressure gradient of 0.6 psi/ft (13.6 kPa/m) increases the gas price to \$30.69/Mcf (\$1.08/m³).

The initial reservoir pressure also affects the methane solubility in brine. When corrections to the gas content are taken into account, the differences in the estimated wellhead gas prices become more pronounced. The prices now range from \$34.60/Mcf (\$1.22/m³) for the 0.6-psi/ft (13.6-kPa/m) pressure gradient to \$11.31/Mcf (\$0.40/m³) for 0.9-psi/ft (20.4-kPa/m).

Permeability

Fig. 6 shows the production histories related to changes in permeability. In the case of the Pleasant Bayou

Fig. 5—Production histories, varying initial reservoir pressure.

research well, a deeper formation was tested and determined to have a very low permeability, but the aquifer currently being tested has a calculated k (permeability) of about 150 md. Based on this evidence, the range of permeabilities used in this parametric study was 100 to 200 md.

Previous work by Randolph¹ clearly shows that permeability has great economic sensitivity for values lower than about 30 md. However, in the range of 100 to 200 md considered in this study, permeability has little cost impact. Wellhead gas price estimates range from \$15.28/Mcf (\$0.54/m³) for 200 md to \$15.68/Mcf (\$0.55/m³) for 100 md. The implication is that for larger k values, the cost sensitivity is relatively small.

Reservoir Parameter Summary

To compare the relative effects of changes in reservoir parameters, a gas price resulting from a given simulation is plotted against the ratio of a varied parameter to its corresponding base case value. The lines in Fig. 7 illustrate the effects of the increase or the decrease of reservoir parameters as they vary from the base case. This diagram clearly points out the importance of the initial reservoir pressure, GWR, and reservoir radius.

However, the gas prices plotted for the initial reservoir pressures have included corrections for the GWR's of the solution gas. Furthermore, the positive effect of greater reservoir pressures is limited to a maximum pressure gradient of about 1.0 psi/ft (22.6 kPa/m). In addition, while the effect of the reservoir radius appears substantial, it also is limited by the extensive faulting in the area. Values chosen for this study for pay zone thickness, rock compressibility, and permeability had considerably less effect on the wellhead price of gas.

The impact of the GWR on the wellhead price of gas is apparent in Fig. 7. While pressure, temperature, and

TABLE 3—GAS PRICES FOR VARYING VOLUME

Thickness		Volume		Wellhead Price	
(ft)	(m)	(cu miles)	(km ³)	\$/Mcf	(\$/m ³)
60	18.3	0.29	1.21	24.34	0.86
120*	36.6	0.58	2.42	15.36	0.54
200	61	0.96	4.00	11.97	0.42
400	121.9	1.92	8.00	9.42	0.33

*Base case.

Fig. 6—Production histories, varying permeability.

salinity affect the solubility of methane in brine, GWR is the parameter that perhaps can vary the most—representing undersaturation to containing gas in excess of that which could be in solution.

Selection of Initial Flow Rate

To provide a better understanding of the impact of initial flow rates on the wellhead price of gas, another scenario, involving optimistic reservoir parameters, was developed. Table 4 details those reservoir characteristics.

By varying the initial flow rate from 20,000 to 70,000 B/D (3180 to 11 130 m³/d), a series of production histories were formulated (Fig. 8). With the data generated, the wellhead price of gas could be estimated over the range of interest. Fig. 9 shows the estimated wellhead prices of gas for the different initial production rates and for two GWR's [25 and 35 scf/bbl (4.5 and 6.3 std m³/m³)].

Increased expenses for additional equipment and disposal wells were taken into account. As can be seen in Fig. 9, gas prices decline as the initial flow rate increases up to about 60,000 B/D (9540 m³/d). At the highest initial production rate of 70,000 B/D (11 130 m³/d), the estimated wellhead price increases slightly from \$6.10/Mcf (\$0.21/m³) minimum to \$6.20/Mcf (\$0.22/m³) for the 25-scf/bbl (4.5- std m³/m³) run.

An examination of the production histories in Fig. 8 shows that only for the first 4 years does the 70,000-B/D (11 130-m³/d) initial production rate exceed that of the 60,000-B/D (9540-m³/d) case. After 4 years, the gas production also declines to the point where the 60,000-B/D (9540-m³/d) initial flow rate actually is producing more gas than the higher initial flow rate case.

TABLE 4—RESERVOIR PROPERTIES, OPTIMISTIC CASE

Depth d , ft (m)	14,680 (4474)
Thickness, h , ft (m)	200 (61)
Area, sq miles (km ²)	70.4 (182.3)
Radius of equivalent circular reservoir r_e , ft (m)	25,000 (7620)
Porosity, ϕ	17.6
Permeability k , md	200
Compression drive, C_o , psi ⁻¹ (MPa ⁻¹)	5.5×10^{-6} (0.91×10^{-3})
Pressure p_i , psi (MPa)	13,210 (91)
Gas saturation, scf/bbl (std m ³ /m ³)	25 and 35 (4.5 and 6.3)
Viscosity μ , cp (Pa·s)	0.2 (0.0002)

Fig. 7—Comparison of the effects of reservoir parameters on wellhead gas price.

Fig. 8—Optimistic production histories, varying initial flow rate.

Fig. 9—Gas price as a function of initial production for optimistic case.

This, coupled with a greater investment cost, penalizes the 70,000-B/D (11 130-m³/d) initial production rate.

However, note that the results are based on a hypothetical reservoir with specific properties. Altering reservoir characteristics can change the initial flow rate at which the minimum wellhead gas price occurs. But the trend is clear: A higher initial production rate usually results in a lower price of gas required for a specified IRR.

This assessment serves to verify that with DCF analysis, higher initial production rates make a prospect more attractive. But this mathematical result, in practice, is tempered by two practical considerations:

1. At very high production rates, some damage to the reservoir (such as formation plugging because of precipitates or sand movement) could occur. The result would be a faster decline in production than predicted, resulting in an increased gas price. The computer simulator used for this study could not predict whether such reservoir damage would occur. Nevertheless, it is a real possibility that operators wish to avoid. Thus, in practice, a minimum gas price might occur at somewhat less than the highest initial production rates.

2. Gas sales involve negotiating with another party who would bear the costs of the gathering system and would want long-term, constant-rate production. This minimizes his cost of gathering and provides a high utilization over the depreciable lifetime of the system.

A likely compromise would be constant-rate production for 5 to 10 years. However, the resultant required gas price for a DCF calculation that would give favorable results in this case is about 3 to 12% higher than for a higher initial flow rate that could be achieved with production limited only by reservoir and well characteristics. In other analyses performed, the difference in the gas prices has been as high as 30%, depending on the reservoir properties selected.

Computer Simulation

The previously described parametric studies involve computational procedures and quantitative parameters to simulate reservoirs that exist in nature. Specific important details that were not reflected in these parametric studies have been discussed at length in Ref. 1. However, some mention of these concerns is appropriate at this time.

Relative Permeability

Assuming a methane-saturated brine exists in a geopressured aquifer, the relative permeability effects will result in less gas production than calculated in this report. This is because the declining reservoir pressure will be accompanied by a decrease in the amount of gas in solution. The evolved gas will decrease water saturation very little, hardly affecting the permeability to water. But the evolved gas remains locked in the pores and will not be produced because the relative permeability to gas is essentially zero.

If the gas saturation builds enough to reach the critical gas saturation, the limited gas phase flow is dictated by the relative permeability of the gas to water. Thus, two important points need to be addressed: (1) the critical gas saturation required to induce some gas flow and (2) the nature of the relative permeability curve that describes

the gas flow. These are critical questions that have not been answered in the context of the geopressured aquifer environment.

Further, a reservoir with both 100% pore saturation with water and complete saturation of the brine with methane certainly would be a remarkable coincidence. It seems more likely that a gas-saturated brine would be accompanied by additional free gas trapped in pores in the rock.

Production Increase From Trapped Gas

If an aquifer contains an amount of immobile natural gas, this trapped gas has two desirable effects that would enhance production. However, these effects were not taken into account in these parametric studies.

First, expansion of the trapped gas in the pores may provide an additional drive mechanism that would increase production. Second, once free gas expansion results in a water saturation small enough for the gas saturation in the pore space to exceed the critical gas saturation, flow of the gas phase will begin.

However, these points are dependent on an improved understanding of the previously discussed topics. Work performed by IGT³³ under contract to the Gas Research Inst. (GRI) points out the economic impact of using different relative permeability curves in hydro pressured aquifers. In the cases studied for GRI, the use of different relative permeability curves when trapped immobile gas was present demonstrated wellhead prices that differed by a factor of more than two. Extrapolating this experience to the geopressured aquifer case, predicted gas prices could be affected greatly by the appropriate selection of relative permeability curves. But a better understanding of the geopressured aquifer environment is necessary.

Pressure Dependence of Permeability

The pressure dependence of permeability was assumed constant throughout the productive life of the reservoir. In practice, permeability declines with a decrease in pore pressure as a result of production. But no quantitative laboratory measurements of the relationship between permeability and pressure for gulf coast geopressured aquifers have been published, although there are indications that the magnitude of this effect may be very large.^{34,35,*}

Conclusions

The principle conclusions from this study are as follows.

1. Projections of methane production still contain enormous uncertainties because of the lack of quantitative definition of drive mechanisms, pressure and temperature dependence of permeability, relative permeability to gas and to water, saturation of pores, methane content of brine, and drainage area limitations.

2. Under specific conditions, the price of gas produced from geopressured aquifers can be marginally competitive, although the risks are still too high for the private sector to develop this potential resource.

3. The DCF analysis suggests that to minimize the wellhead gas price of production from a geopressured aquifer, the well should be allowed to flow at a very high

rate even though a rapid but predictable decline in production would result. The often-discussed 5 to 7 years' constant production could result in up to a 30% higher gas price at the wellhead.

4. Economic projections for gas prices from geopressured aquifers are limited to broad ranges until more laboratory research and operating experience can narrow the span of uncertainty for key parameters.

5. As gas prices continue to increase, consideration of certain formations resembling geopressured aquifers but containing dispersed gas, small gas caps, or having associated gas stringers will become marginally attractive. With higher prices, operators will begin to develop these special cases of geopressured aquifers with their expected higher GWR's rather than abandon the well as a dry hole.

6. Environmental and socioeconomic aspects, while a matter of concern, appear not to be real constraints to the development of geopressured aquifers.

Acknowledgment

Much of the data collection and analysis was done under the sponsorship of the U.S. DOE Contract No. DE-AC08-78ET27098. Reservoir-limit test calculations were performed by L. Rogers and D. Clark.

References

1. Randolph, P.L.: "Natural Gas From Geopressured Aquifers?" paper SPE 6826 presented at the SPE 52nd Annual Technical Conference and Exhibition, Denver, Oct. 9-12, 1977.
2. Bernard, W.J.: "Reservoir Mechanics of Geopressured Aquifers," *Proc., First Geopressured-Geothermal Energy Conference*, U. of Texas Press, Austin (1975) 157-172.
3. Weston, J.F. and Brigham, E.F.: *Managerial Finance*, Pryden Press, Hinsdale, IL (1975).
4. Van Horne, J.C.: *Fundamentals of Financial Management*, Prentice-Hall Inc., Englewood Cliffs, NJ (1977).
5. Campbell, J.M., Campbell, J.M. Sr., and Campbell, R.A.: *Mineral Property Economics, Vol. 1*, Campbell Petroleum Series, Norman, OK (1978).
6. Hawkins, M.F. Jr.: "Investigation on the Geopressure Energy Resource of Southern Louisiana," Review Report No. ORO-4889-12, Louisiana State U., Baton Rouge, LA (Dec. 1976).
7. Hawkins, M.F. Jr.: "Investigations on the Geopressure Energy Resource of Southern Louisiana," Final Report No. ORO-4889-14, Louisiana State U., Baton Rouge, LA (April 1977).
8. Bebout, D.G., Dorfman, M.H., and Agagu, O.K.: "Geothermal Resources Frio Formation, South Texas," U. of Texas, Austin (July 1976).
9. Bebout, D.G., Loucks, R.G., and Gregory, A.R.: "Frio Sandstone Reservoirs in the Deep Subsurface Along the Texas Gulf Coast," Report No. 91, U. of Texas, Austin (1978).
10. Loucks, R.G., Dodge, M.M., and Galloway, W.E.: "Sandstone Consolidation Analysis to Delineate Areas of High-Quality Reservoirs Suitable for Production of Geopressured-Geothermal Energy Along the Texas Gulf Coast," Report No. ORO-5554-1, U. of Texas, Austin (Jan. 1979).
11. Bebout, D.G., Loucks, R.G., and Gregory, A.R.: "Wilcox Sandstone Reservoirs in the Deep Subsurface Along the Gulf Coast, Their Potential for Production of Geopressured Geothermal Energy," U. of Texas, Austin (Oct. 1979).
12. Doscher, T.M., Osborne, R.H., Wilson, T., Rhee, S., Cox, D., and Kuuskraa, V.: "The Technology and Economics of Methane Production From Geopressured Aquifers," *J. Pet. Tech.* (Dec. 1979) 1502-1514.
13. Swanson, R.K., Osoba, J.S., Berg, R.R., Hankin, J.W., Kroger, G.S., Lantz, R.B., and Miklas, M.: "Geopressured Energy Availability," Final Report to Electric Power Research Inst., EPRI AP-1457, Project 1272-1 (July 1980).

*Bebout, D.G.: personal communication, U. of Texas, Austin (Dec. 1976).

14. Hankins, B.E. and Karkalits, O.C.: "Geopressured-Geothermal Test of the Edna Delcambre No. 1 Well, Tigre Lagoon Field, Vermillion Parish, Louisiana: Analysis of Water and Dissolved Natural Gas," Report No. ORO-4937-T1, U. of Texas, Austin (Sept. 1978).
15. Dobson, R.J., Hartsock, J.H., and Sillits, M.H.: "Investigation and Evaluation of Geopressured-Geothermal Wells. Final Report. Gladys McCall No. 1 Well, Cameron Parish, Louisiana," Report No. NVO-1528-4, Gruy Federal Inc., Houston (Jan. 1979).
16. Willits, M.H., McCoy, R.L., Dobson, R.J., and Hartsock, J.H.: "Investigation and Evaluation of Geopressured-Geothermal Wells. Final Report. Fairfax Foster Sutter No. 2 Well, St. Mary Parish, Louisiana, Vol. II," Gruy Federal Inc., Houston (Dec. 1979).
17. Willits, M.H., McCoy, R.L., Dobson, R.J., and Hartsock, J.H.: "Investigation and Evaluation of Geopressured-Geothermal Wells. Final Report. Fairfax Foster Sutter No. 2 Well, St. Mary Parish, Louisiana, Vol. I," Gruy Federal Inc., Houston (Dec. 1979).
18. Matthews, C.L.: "Existence and Flow Behavior of Gas at Low Saturation in Geopressured Formations," U.S. DOE Report HCP/T2259-05 (April 1979).
19. Rogers, L.A. and Randolph, P.L.: "Ratio of Produced Gas to Produced Water From DOE's Edna Delcambre No. 1 Geopressured-Geothermal Aquifer Gas Well Test," paper presented at the Fourth Annual U.S. Gulf Coast Geopressured-Geothermal Energy Conference, Austin, TX, Oct. 29-31, 1979.
20. Newchurch, E.J., Bryan, C.F., Harrison, D.P., Muller, R.A., Wilcox, R.E., Bachman, A.L., Newman, J.P., Cunningham, K.J., Hilding, R.K., and Rehage, J.A.: "A Plan for the Long Term Environmental Assessment of Geopressured Resource Development in the Louisiana Gulf Coast Region," Inst. for Environmental Studies, Baton Rouge, LA (July 1978).
21. Newchurch, E.J., Bachman, A.L., Bryan, C.F., Harrison, D.P., Muller, R.A., Newman, J.P., Smith, C.G., Bailey, J.I., Kelley, G.G., and Reibert, K.C.: "A Preliminary Environmental Assessment of Selected Geopressured-Geothermal Prospect Areas: Louisiana Gulf Coast Region, Vol. I," Inst. for Environmental Studies, Baton Rouge, LA (Oct. 1978).
22. Newchurch, E.J., Bachman, A.L., Bryan, C.F., Harrison, D.P., Muller, R.A., Newman, J.P., Smith, C.G., Bailey, J.I., Kelley, G.G., and Reibert, K.C.: "A Preliminary Environmental Assessment of Selected Geopressured-Geothermal Prospect Areas: Louisiana Gulf Coast Region, Vol. II," Inst. for Environmental Studies, Baton Rouge, LA (Oct. 1978).
23. White, W.A., McGraw, M., and Gustavson, T.C.: "Environmental Analysis of Geopressured-Geothermal Prospect Areas, Brazoria and Kennedy Counties, Texas," U. of Texas, Austin (1978).
24. Knutson, C.F. and Boardman, C.R.: "An Assessment of Subsurface Salt Water Disposal Experience on the Texas and Louisiana Gulf Coast For Application to Disposal of Salt Water From Geopressured Geothermal Wells," Report No. NVO-1531-2, C.K. Geoenergy Corp., Las Vegas (Aug. 1978).
25. "An Analysis of Ecological Effects of Geopressured-Geothermal Resource Development," RPC Inc., Austin, TX (July 1979).
26. "Geopressured-Geothermal Energy Development: Social and Economic Issues," RPC Inc., Austin, TX (July 1979).
27. Culberson, O.L. and McKetta, J.J. Jr.: "Phase Equilibrium in Hydrocarbon-Water Systems, III. The Solubility of Methane in Water at Pressures to 10,000 psia," *Trans., AIME* (1950) 189, 319-322.
28. Dodson, C.R. and Standing, M.B.: "Pressure-Volume-Temperature and Solubility Relations for Natural Gas Water Mixtures," *Drill. and Prod. Prac.* (1945) 173-179.
29. Price, L.C., Blount, C.W., MacGowan, D., and Wenger, L.: "Methane Solubility in Brines With Application to the Geopressured Resource," *Proc., Fifth Geopressured-Geothermal Energy Conference, Louisiana State U., Baton Rouge* (Oct. 1981) 205-214.
30. Price, L.C.: "Aqueous Solubility of Methane at Elevated Pressures and Temperatures," *Bull., AAPG* (Sept. 1979).
31. Rowe, A.M. and Chou, J.C.: "Pressure-Volume-Temperature Concentration Relation of Aqueous NaCl," *J. Chem. Eng. Data* (1970) 15, 61-66.
32. Gray, K.E. and Thompson, T.W.: "Compaction Measurements on Texas Gulf Coast Sandstones and Shales," Monthly Letter Report for July 1979, DOE Contract No. DE-AC08-79ET27112, U. of Texas, Austin (Aug. 6, 1979).
33. Doherty, M.G.: "Analysis of Geopressured Aquifers," Quarterly Progress Report for April-June 1980, GRI Contract No. 5011-310-0109 (July 7, 1980).
34. Swanson, R.K., Oetking, P., Osaba, J.S., and Hagens, R.C.: "Development of an Assessment Methodology for Geopressured Zones of the Upper Gulf Coast Based on a Study of Abnormally Pressured Gas Fields in South Texas," Southwest Research Inst., San Antonio, TX (Aug. 1976).
35. Thomas, R.D. and Ward, D.C.: "Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores," *J. Pet. Tech.* (Feb. 1972) 120-124.

APPENDIX

The simulation used for this paper consists of two independent computer programs, "Aquaflow" and "Econanal," that have the option of being linked for continuous analysis. Output from the reservoir simulation is stored on disk for use by the DCF program, for plotting graphs, or for other analytical purposes.

The reservoir model simulates a one-dimensional, one-phase, bounded, circular aquifer. The basic reservoir engineering techniques used in the model are found in Ref. 2.

The semisteady-state condition for the aquifer is calculated by the following equation.

$$t_s = \frac{0.04\mu c \phi r_e^2}{k}$$

where

- t_s = time to semisteady state, days,
- μ = fluid viscosity, cp (Pa·s),
- c = total compressibility, psi⁻¹ (Pa⁻¹),
- ϕ = porosity, fraction,
- r_e = reservoir radius, ft (m), and
- k = permeability, md.

The wellhead pressure during transient flow—i.e., for times less than the stabilization time—is approximated by

$$p_w = p_i - \frac{q\mu}{14.16 kh} \left[\ln \left(\frac{14.22 kt}{\phi \mu c r_w^2} \right) \right] - p_f - p_h$$

where

- p_w = wellhead pressure, psi (kPa),
- p_i = initial reservoir pressure, psi (kPa),
- q = water production, B/D (m³/d),
- h = producing zone thickness, ft (m),
- t = time, days,
- r_w = wellbore radius, ft (m),
- p_f = pressure drop caused by friction in tubing, psi (kPa), and
- p_h = hydrostatic head in wellbore, psi (kPa).

The wellhead pressure during semisteady-state condition—i.e., for times after the stabilization time—is approximated by

$$p_w = p_i - \frac{q\mu}{7.08 kh} \left[\ln \left(\frac{r_e}{r_w} \right) - 0.75 \right] - p_f - p_h$$

The frictional pressure drop in the production tubing is calculated by a subroutine that could be rough, average, or smooth in terms of the roughness indicator for the tubing as selected by the user.

Fig. A-1—Basic flow diagram of reservoir simulation model.

The program runs over a specified time period or until an operator-specified low flow restriction or upper hydraulic horsepower (kilowatt) limit for pumping is reached. Time steps are selected by the user. For the purpose of this study, annual brine production was chosen for the output. Fig. A-1 illustrates the basic flow of the "Aquaflow" program.

The economic evaluation program merges the brine production history with a selected GWR assuming production of only solution gas. However, estimates in terms of average GWR's for production of gas in excess of that in solution are possible, or variable GWR's over time are an option.

Input parameters as indicated by the basic flow chart (Fig. A-2) are entered. The program can account for gas consumed on site for the operation of injection pumps for brine disposal and other uses. In this way, the project can be evaluated strictly on its own merits without the purchase of outside energy forms to subsidize a potentially more costly energy source. On the other hand, if the gas produced from a geopressured aquifer for a given IRR is less expensive or if the prices paid for the produced gas are higher than those of outside energy sources, the program has the option of including the additional operating expenses for electricity and/or diesel fuel to run the surface equipment.

Fig. A-2—Flow diagram for discounted cash flow analysis.

The economic analysis has the flexibility of performing three types of calculations: NPV for given gas prices and discount factor, IRR for given gas prices, and gas price required for a specified IRR (including escalating gas prices). The third option was used for the analyses performed for this paper. A 15% after-tax IRR was required and gas prices remained constant.

A table of annual cash flows including brine and gas production, various operating expenses, depreciation, taxes, etc. are printed out and can be stored on disk for future reference. Sensitivity to economic inputs can be assessed, the results from another reservoir simulation can be analyzed, or the process can be terminated at this point.

SI Metric Conversion Factors

bbl	×	1.589 873	E-01	=	m ³
cu ft	×	2.831 685	E-02	=	m ³
ft	×	3.048*	E-01	=	m
psi	×	6.895 757	E+00	=	kPa
scf	×	2.863 64	E-02	=	std m ³

*Conversion factor is exact.

JPT

Original manuscript received in Society of Petroleum Engineers office July 23, 1980. Paper accepted for publication Oct. 9, 1981. Revised manuscript received April 16, 1982. Paper (SPE 9468) first presented at the SPE 55th Annual Technical Conference and Exhibition held in Dallas Sept. 21-24, 1980.

APPENDIX B.

IGT Test Activities On The MG-T/DOE
Amoco Fee No. 1 Well During August, 1981

IGT TEST ACTIVITIES ON THE MG-T/DOE AMOCO FEE NO. 1 WELL DURING AUGUST 1981

**C. G. Hayden
P. L. Randolph
T. L. Oslif**

**Prepared by
Institute of Gas Technology
IIT Center, 3424 S. State Street
Chicago, Illinois 60616**

October 1981

IGT TEST ACTIVITIES ON THE MG-T/DOE
AMOCO FEE NO. 1 WELL DURING AUGUST, 1981

by

C. G. Hayden, P. L. Randolph, T. L. Osif

INSTITUTE OF GAS TECHNOLOGY

Introduction

The first month of production testing of the MG-T/DOE Amoco Fee No. 1 well by the operator suggested gas content of brine of less than half of expected values. However, at the same time, it was recognized that problems existed in flow metering and that some sample analyses provided results inconsistent with understanding from prior tests of other wells. Some of these issues are discussed in the Background section of this report.

During August 1981, IGT personnel collected and analyzed samples of gas and brine from the separator during testing of the MG-T/DOE Amoco Fee No. 1 well. Various portions of this work and the related reviews of data developed by participants in the well test were performed in accordance with the statements of work for a) IGT's DOE-sponsored project "Computer Simulation of Geopressured Aquifers," b) IGT's GRI-sponsored project "Gas From Formation Waters," and c) a purchase order to IGT from Magma Gulf-Technadril. In the interest of completeness, and with concurrence of the sponsors, work performed under these projects is consolidated into this single report.

IGT focus was on three questions:

- What is the quantity and quality of gas leaving the separator dissolved in the disposal brine?
- Is the reservoir saturated with gas?
- In what ways does the chemistry of the produced brine affect gas behavior and partitioning between phases?

Achieving meaningful conclusions on these subjects has required substantial departures from the sampling schedule and sample handling procedures prescribed in the procedures manual for geopressured fluids developed for DOE (Ref. 1). For this reason, the procedures used and results of analyses performed are described here in considerable detail. Discussions addressing the above three questions are then presented. Conclusions and recommendations are summarized in the last sections of this report.

Background

Preliminary data obtained by MG-T and its contractors indicated that the gas and brine effluents were considerably different than had previously been seen by IGT on the Wells of Opportunity (WOO) program. The chemistry of the brine was different from the low-salinity brines observed on wells IGT had tested, but was consistent with the high volume producing design wells. The quantity of gas produced, as well as the gas lost in disposal brine, was inconsistent with previously expected values based on solubility data. These observations will be discussed in more detail in the following sections.

Brine chemistry data supplied to IGT by Dr. B. E. Hankins of McNeese State University on August 5, 1981 indicated a high salinity, high calcium content for the produced fluids (Ref. 1). Analysis results transmitted verbally were as follows:

pH		5.66
Alkalinity		261 mg HCO_3^-/ℓ
Total Dissolved Solids		166,500 mg/ ℓ
Na	46,000 mg/ ℓ	K 1740 mg/ ℓ
Cl	99,350 mg/ ℓ	NH_3 88 mg/ ℓ
Ca	11,000 mg/ ℓ	B 62 mg/ ℓ
Mg	670 mg/ ℓ	Fe 59 mg/ ℓ
Sr	850 mg/ ℓ	SiO_2 112 mg/ ℓ

Gas measurements and analyses had previously been done by MG-T and Weatherly Laboratories, Inc., personnel. Flare line gas metering problems were identified, and much progress had been made by early August in resolving discrepancies. Early reported gas-to-brine ratios ranged from 8 to 12 SCF/STB. John Neal of Weatherly Laboratories, Inc. (Ref. 2) performed a recombination using 8.1 SCF/STB as the produced gas-to-water ratio (GWR) and found the corresponding bubble point of the reservoir would be approximately 2006 psia. If gas and brine metering were correct, it would appear that the reservoir was undersaturated. John Neal's recombination studies also indicated that ~34.3 SCF/STB would be required for saturation at reservoir pressure and temperature. Accumulation of gas in the high-pressure corrosion coupon bypass line provided evidence that two phases existed at the wellhead when wellhead pressure was greater than 2000 psi. This suggested that more than 8.1 SCF/STB were actually being produced.

The analysis of the flare line gas used in the recombination is given below:

<u>Mole % (dry)</u>		<u>Mole % (dry)</u>	
Carbon Dioxide	7.00	<u>n</u> -Butane	0.03
Nitrogen	0.29	iso-Pentane	0.00
Methane	90.65	<u>n</u> -Pentane	0.01
Ethane	1.66	Hexanes	0.00
Propane	0.27	Heptanes +	0.07
iso-Butane	0.02		

Other flare line gas analyses exist, and are comparable with the above.

Weatherly Laboratories also measured the quantity and composition of gas still remaining in the disposal brine. The value measured in the recombination study was 0.9 SCF/STB (dry). The composition of this gas as given in Weatherly's report is as follows (Ref. 2):

<u>Mole % (dry)</u>		<u>Mole % (dry)</u>	
Carbon Dioxide	12.3	<u>n</u> -Butane	0.0
Nitrogen	—	iso-Pentane	0.0
Methane	85.8	<u>n</u> -Pentane	0.0
Ethane	1.6	Hexanes	0.0
Propane	0.3	Heptanes +	0.0
iso-Butane	0.0		

IGT experience with this type of analysis indicated that the CO₂ content was surprisingly low and may be caused by the high calcium content of the brine. Several measurements were made by Weatherly Laboratories of the amount of gas remaining in the brine after the separator. Most of these gave values similar to those obtained at WOO wells having comparable separator temperature and pressure. However, a measurement on July 28, 1981, gave a solution GWR of 8.3 SCF/STB (Ref. 3). This value is completely inconsistent with proper separator operation. It is not clear whether the anomalous result was due to separator malfunction or to a problem with sample collection. The bubble point exhibited by the sample was 870 psia, or ~630 psi above the sample collection pressure.

IGT Sampling Procedures for Gas and Brine

IGT has developed sampling and analysis procedures on Wells of Opportunity tests to accurately measure the total gas production from a

geopressured geothermal well. These procedures were modified to compensate for the lack of an onsite gas chromatograph and an acid liberation-nitrogen purge carbonate train. Emphasis was placed on collecting both brine and gas samples and performing a hydrogen sulfide analysis in 15 minutes. Brine and gas samples are collected in as short a time as possible to minimize the chance that any change in conditions (flowing or compositional) will occur during the sampling procedure. Hydrogen sulfide instability necessitates rapid analysis for accurate results.

- Flare line gas samples were caught in preheated Teflon-lined stainless steel sample cylinders. The cylinders were preheated to above 100°C to minimize water condensation within the sample vessel. The closed valve ends were fitted with Swagelok caps to prevent leaks, and the sample was shipped to IGT for analysis.
- The gas samples were heated at IGT to a temperature greater than 100°C and analyzed using a mass spectrometer.
- Draeger hydrogen sulfide analyses of the flare line gas samples were performed using procedures outlined in Gas Processors Association's Tentative Method of Test for Hydrogen Sulfide in Natural Gas Using Length of Stain Tubes. The same procedure is used for flare line Draeger CO₂ determinations, although CO₂ is also quantified in the mass spectrometer analysis.
- At least two brine samples were caught each time in Teflon-lined stainless steel pressure vessels at separator pressure and temperature. The closed valve ends were sealed with Swagelok caps and quickly cooled by immersion into a cold water bath. One of the samples from each set was shipped to IGT for analysis, and the other was partially analyzed in the field and then discarded.
- The brine analysis consisted of several steps. The first was to reduce pressure on the cooled brine to 1 atmosphere by using a large syringe. The syringe was connected to the cylinder valve and the valve opened. The exsolved gas pushed the plunger in the syringe. After the cylinder was struck several times to enhance gas dissolution, the gas volume was read directly off the syringe. The brine was emptied into a graduated cylinder and its volume noted. At this point the field samples were discarded.

Several more analytical steps were performed on samples shipped to IGT as follows:

- The gas was analyzed using a mass spectrometer.
- The brine was divided into two portions and measured. The first portion was immediately treated with sodium hydroxide to stabilize the CO₂ in solution (going to a pH of ~10). The second portion of the sample was untreated.

- A representative sample of the alkaline brine was treated with acid and purged with nitrogen, quantitatively trapping and measuring the exsolved CO₂. This procedure measures "total CO₂," which includes dissolved CO₂, bicarbonate, and carbonate species.
- A portion of the untreated brine was titrated with sulfuric acid to determine alkalinity. The remaining untreated brine was then acidified and analyzed for calcium content.

Results of IGT Analyses

IGT performed several types of analyses to help define gas production for this well. Table 1 contains results of flare line gas analyses. (All reported pressures have been corrected for instrument drift by subtracting 70 psi from all originally read values as instructed by Larry Durrett. All pressure, temperature, and flowrate data were provided by MG-T.) Gas analyses were performed at IGT with a DuPont Model 21-104 mass spectrometer. It is important to note that the cylinders were heated prior to analysis to avoid liquid water, which would dissolve CO₂ and cause erroneous measurements.

When the flow rate was increased from about 1400 BPD to over 15,000 BPD the temperature of the produced brine rose from ~160° to 275°F. At 275°F flowing brine temperature, the gas stream contained so much water vapor that condensation may still have occurred in the preheated gas cylinders. Some CO₂ probably remained in solution in this liquid phase in the cylinders when gas was withdrawn for laboratory analysis.

The high water content at 275°F was also a problem when using Draeger tubes in the field. Table 2 is a summary of the Draeger tube analyses performed. Note that no analyses were performed after the large flow rate increase on August 11. It was felt that the water interference at that point made the results unreliable.

The hydrogen sulfide concentration on August 10, 1981 was measured after a shut-in period. It is believed the low value is due to the reaction of hydrogen sulfide with tubulars during this shut-in.

Table 3 presents the amount of gas liberated from cooled disposal brine upon reducing pressure to 1 atmosphere. It is important to note that all of the liberations performed at IGT on stored samples yielded lower GWR's than did similar flashes performed in the field.

10/81

Table 1. MASS SPECTROMETRIC ANALYSES OF
FLARE LINE GAS, MOLE PERCENT

Date	8-7-81	8-7-81	8-10-81	8-11-81	8-11-81	8-12-81	8-12-81	8-12-81
Time	1045	1830	1220	1840	1937	1130	1420	1605
Brine Rate (BPD)	~1400	~1400	~1400	>15,000	>15,000	>15,000	>15,000	>15,000
Separator Pressure (psia)	236	239	256	480	445	464	348	579
Brine Temperature (°F)	160	160	165	244	275	275	275	275
Methane	89.28	88.77	90.04	90.14	89.45	89.15	88.87	89.78
Ethane	1.74	1.73	1.68	1.83	1.72	1.50	1.40	1.48
Propane	.39	.35	.33	.38	.35	.23	.23	.23
n-Butane	.05	.06	.04	.06	.05	.03	.03	.03
i-Butane	.02	.04	.02	.02	.00	.00	.00	.01
Pentanes	.01	.01	.01	.02	.02	.00	.01	.00
Hexanes	.00	.00	.00	.00	.00	.00	.00	.00
Benzene	.10	.13	.03	.05	.05	.04	.06	.03
Tolulene	.07	.09	.01	.03	.03	.02	.03	.01
Xylene	.00	.01	.00	.00	.00	.00	.00	.00
Hydrogen	.01	.00	.04	.02	.04	.00	.00	.01
Nitrogen	.20	.22	.37	.15	.23	.24	.21	.24
Carbon Dioxide	8.13	8.59	7.43	7.30	8.06	8.79	9.16	8.18

10/81

Table 2. DRAEGER GAS ANALYSIS OF FLARE LINE GAS

<u>Date</u>	<u>Time</u>	(psig) <u>Pressure</u>	(°F) <u>Temperature</u>	(ppm) <u>H₂S</u>	(vol. %) <u>CO₂</u>
8-7	1030	291	160	22	9
8-7	1800	294	160	22	8
8-8	0800	303	167	25	8.5
8-10	1205	311	165	13*	7.8

* The H₂S probably reacted with tubulars during the preceding shut-in period.

10/81

Table 3. GAS LIBERATED FROM BRINE AFTER THE SEPARATOR
BY PRESSURE REDUCTION TO 1 ATMOSPHERE

Date	Time	Pressure, psia	Temperature, °F	Gas-Brine Ratio	
				Field*	IGT Chicago** SCF/STB
8-7	1030	236	160	1.56	1.39
8-7	1800	239	160	1.62	1.12
8-8	0800	248	167	1.71	
8-10	1205	256	165	1.67	1.53
8-11	1840	480	244	2.91	2.10
8-12	1130	464	275	2.99	
8-12	1130	464	275	3.05	
8-12	1420	348	275	2.36	1.96
8-12	1605	569	275	3.76	3.15

* Pressure reduction done in the field less than one hour after sample collection.

** Pressure reduction and analyses done at IGT-Chicago several days after sample collection.

Table 4 contains results of the analyses performed on the six brine samples analyzed at IGT. Included is the liberated gas analysis, pH, solution CO_2 , alkalinity, acidity, and the calcium concentration. The gas analyses were performed on gas at ambient temperature using a mass spectrometer. Solution CO_2 values contain the total amount of CO_2 in all forms including dissolved CO_2 and various carbonate species remaining in solution at 1 atmosphere. The acidity is a very rough measurement made by counting the number of drops (in units of 10) of aqueous sodium hydroxide needed to make a portion of the brine alkaline (pH ~10). Calcium concentrations were measured using standard atomic absorption techniques used by IGT's analytical laboratory for brine analyses.

Upon trying unsuccessfully to perforate a deeper zone, it was found that the well bore had filled with several hundred feet of solids below the producing interval. IGT performed a preliminary analysis of solids recovered with a wireline bailer. The analysis first entailed manual separation of tubing liner material (plastic) from the rest of the solids. It was found that 7.7% by weight of the small sample provided to IGT was liner material. The remaining solids were then washed with 1N HCl, to dissolve salts and carbonates. Weight loss due to removal of these components was 7.0% of the sand or 6.5% of the original solids.

Discussion

The three objectives this study set out to answer are as follows:

- To determine the quantity and composition of the gas leaving the separator dissolved in the disposal brine
- To determine whether the reservoir is saturated with gas
- To determine how the chemistry of the produced brine affects gas behavior and partitioning between phases.

The discussion of our results and conclusions is presented by treating each of these topics in a separate section.

I. Quantity and Composition of Gas Remaining in Disposal Brine

The data collected in the field are presented graphically in Exhibit 1. The dashed line is a least-squares linear fit to the data. The correlation is excellent ($r^2 = 0.988$) with a y intercept of 0.12 SCF/STB. An intercept of 0.0 is expected if the data are collected at a constant temperature. Gas

Table 4. ANALYSIS OF BRINE AND GAS FLASHED FROM THE BRINE SAMPLES FROM THE
MG-T/DOE AMOCO FEE WELL NO. 1, SWEET LAKE PROSPECT, CAMERON PARISH, LA.

10/81

Component	Units	8-7-81 1030 hrs	8-7-81 1845 hrs	8-10-81 1215 hrs	8-11-81 1836 hrs	8-12-81 1420 hrs	8-12-81 1605 hrs
Gas Analysis							
Methane	mole %	74.09	79.10	74.81	78.91	80.28	77.17
Ethane	mole %	1.17	1.20	1.15	1.18	1.03	1.00
Propane	mole %	0.13	0.15	0.14	0.15	0.10	0.11
n-Butane	mole %	0.004	0.003	0.003	0.004	0.003	0.003
iso-Butane	mole %	0.002	0.001	0.001	0.003	0.001	0.001
Benzene	mole %	0.02	0.03	0.03	0.03	0.02	0.04
Toluene	mole %	0.005	0.004	0.004	0.006	0.006	0.008
Carbon Dioxide	mole %	24.58	19.51	23.86	19.72	18.56	21.67
Caloric Content	Btu/SCF	763	815	771	812	822	791
Specific Gravity	--	0.801	0.752	0.794	0.754	0.742	0.772
Liquid Analysis							
Alkalinity	mg HCO_3^-/L	320	430	290	286	150	141
Total CO_2	SCF/STB	1.52	1.71	1.67	1.70	1.13	1.40
Solution CO_2	mg NaOH/L	24,000	9,000	9,000	22,000	25,000	25,000
Calcium	mg Ca^+/L	12,200	11,600	11,800	11,500	11,500	11,600
pH	--	6.1	6.2	6.0	6.0	5.5	5.4

Exhibit 1. COMPARISON OF FIELD MEASUREMENTS WITH VALUES CALCULATED WITH THE S^3 ALGORITHM

solubility is temperature dependent, and this effect is greater for carbon dioxide than for methane. The separator pressure has a water vapor pressure component which is temperature dependent. Brine temperature was not constant during data collection, which may account for the small positive intercept.

The solid line in Exhibit 1 is from an algorithm developed by Systems Science and Software (S^3) (Ref. 4) to fit Culberson and McKetta's data for methane solubility in water (Ref. 5). This algorithm has been found by IGT to closely fit the total gas liberated by pressure reduction to 1 atmosphere from disposal brine in WOO wells. Note that the S^3 prediction is above the values measured for the MG-T well. This difference may be in part due to vapor pressure of water in the separator being higher than on WOO tests because the brine temperature is higher (275°F). The low total gas values are not due to an insufficiency of methane, but do reflect smaller amounts of carbon dioxide.

The amount of methane contained in the MG-T disposal brine is compared with the amount contained in the HO&M Prairie Canal Co., Inc., Well No. 1 (Ref. 6) in Exhibit 2. The x-axis is expressed as partial pressure of methane to eliminate contributions of other gases. These data can be compared because the effect of temperature on methane solubility in this range, under these conditions, is small compared to the pressure effect. The amount of methane in the disposal brine is greater, at a given partial pressure, for the MG-T well than for the Prairie Canal well. However, the amount of total gas in the disposal brine is less for the MG-T well than for the Prairie Canal well. This difference in total gas is largely carbon dioxide, which is the only component present in quantities large enough to account for this difference. One would predict that the methane solubility in the MG-T disposal brine would be less than in the Prairie Canal brine based on the higher salinity of the MG-T well. Because this was not observed, another mechanism may exist for reducing methane solubility in the Prairie Canal well vs. the MG-T well.

Blount (Ref. 7) has demonstrated that carbon dioxide decreases methane solubility in water when the carbon dioxide content of the dissolved gas exceeds 15%. The MG-T gas liberated from the disposal brine contained ~20% carbon dioxide, while the Prairie Canal well disposal brine liberated gas containing ~30% carbon dioxide. With the inhibiting effect on methane solubility dependent on the percentage of the gas which is carbon dioxide, it is not unreasonable to expect the MG-T disposal brine to contain more methane

Exhibit 2. COMPARISON OF AMOUNTS OF METHANE REMAINING IN DISPOSAL BRINE BETWEEN THE MG-T/DOE AMOCO FEE NO. 1 and the HO&M PRAIRIE CANAL CO., INC. WELL # 1

than the Prairie Canal well, as observed. We conclude from the above discussion that the MG-T disposal brine contained less total gas than did Prairie Canal, but contained more methane at a given partial pressure than Prairie Canal.

Another possibility is that the previously mentioned 70 psi correction to separator pressure was not the appropriate correction for the actual time of sample collection. It is conceivable that future analyses, accompanied by accurate pressure data, will reveal that total gas in solution in separator brine, rather than the methane component, will be consistent with results from WOO tests. This consistency was observed for samples from the Pleasant Bayou No. 2 well collected in October, 1980 (Ref. 8).

Exhibit 3 is a plot comparing gas liberations done in the field to those performed later at IGT. The line in Exhibit 3 is a least-squares linear fit to the field data presented in Exhibit 1. The liberations performed at IGT all had a lower GWR than those done in the field. This indicates a loss through leaks or reactions with the sample vessel. The sample vessel is Teflon-lined stainless steel, which is fairly inert to most gases and to CO₂-carbonate systems, although a small amount of hydrogen gas was detected in some samples. In addition, an acid wash was performed on one empty cylinder to look for deposited carbonates, but none were found (less than 0.1 SCF CO₂/STB equivalent in carbonate). Leaks apparently are the primary cause of this occurrence. The leaks were trivial on WOO tests where the analysis was completed within 30 minutes after sampling. On wells where the IGT field lab is not available and the analyses are necessarily postponed, this becomes a problem. Most of the cylinders were equipped with new valves. The problem was still significant, and a different type valve may be required on future tests.

The conclusions pertinent to well operation are not substantially affected by these problems. At 1000 psi separator operating pressure, 6.3 ± 0.5 SCF/STB of gas will be lost in the disposal brine. This gas will have a heating value of about 5000 to 6000 Btu/STB. Secondary recovery of this gas is dependent upon disposal pressure requirements and the accompanying economic factors.

Exhibit 3. COMPARISON OF FIELD ANALYSES TO ANALYSES OF
SAMPLES AT IGT

II. Gas Content of Reservoir Brine

Determining whether or not the reservoir brine is saturated with gas is a major objective of DOE well tests. Unfortunately, the conventional method used to determine saturation by comparing produced gas-to-brine ratios against recombination data has had many problems. Gas-to-brine production ratios had not been measured with the accuracy required for meaningful comparisons to recombination data. On this well, for instance, John Neal of Weatherly Laboratories (Ref. 2) stated that the reservoir fluid exhibited a bubble point of 2006 psia and 299°F when recombining the "produced GWR" of 8.1 SCF/STB, and that the brine was undersaturated at reservoir conditions. It has since been found that the produced GWR is substantially above the 8.1 SCF/STB, which was considered accurate when Weatherly took their samples. IGT has recognized that this problem exists on many well tests and is using an independent test to deduce reservoir saturation conditions through other surface manifestations. This has resulted in the "bubble test," the theory and practice of which will be discussed below.

The theory is based on the premise that gas in contact with an aqueous phase will have a different composition than the dissolved gas with which it is in equilibrium. This is expected because the various gaseous components have different fugacities and subsequently different solubilities in the aqueous phase. For the natural gas-CO₂ system common in geopressured aquifers, the free gas phase has a lower CO₂ content and higher ethane, propane, and butane contents relative to methane than does the dissolved gas. The magnitude of variations in concentrations is illustrated by the Weatherly Laboratories analyses of gases from four steps in differential liberation shown in Table 5. The data shown are from the Riddle-Saldana Well No. 2 (Ref. 11) samples that had been recombined to actual reservoir pressure and temperature.

The compositional differences are related to reservoir behavior through the following model: Assume that a reservoir contains no free gas phase at reservoir pressure and temperature. As brine is produced, the pressure around the well bore drops. If the pressure falls below the bubble point, gas is differentially liberated from the brine and is trapped in the pore space. Gas accumulates in the pore space until critical saturation is reached. At this point a quasi-steady state is reached in which a small amount of free gas may

10/81

Table 5. COMPOSITIONS DURING DIFFERENTIAL LIBERATION OF GAS FROM BRINE, RIDDLE-SALDANA WELL NO. 2

Pressure Step, psia	6632-4000	4000-2500	2500-1000	1000-15
Total Gas, SCF/STB	6.8	7.7	10.8	17.0
Gas Composition, mol %				
CO ₂	1.80	3.05	8.76	18.64
Methane	92.24	92.74	88.46	79.18
Ethane	4.43	3.44	2.44	1.85
Propane	0.96	0.54	0.26	0.10
n-Butane	0.19	0.07	0.02	0.01
i-Butane	0.18	0.07	0.02	0.03
n-Pentane	0.08	0.02	0.01	<0.01
i-Pentane	0.05	0.01	0.01	<0.01
Hexanes	0.03	0.01	<0.01	<0.01
Heptanes+	0.04	0.05	0.02	0.19

flow into the well bore but it is being replenished by additional solution gas being differentially liberated from the brine. It is important to note that this free gas which is trapped in the reservoir contains more ethane, propane, and butanes relative to methane than does the solution gas which is being produced. The free gas phase accumulating around the well bore thus has a characteristically different composition than does the solution gas.

If the flow rate is increased, there is a sudden, large pressure drop around the well bore, and the steady state condition no longer exists. Free gas immediately around the well bore expands, coalesces, and flows into the well bore. As this free gas reaches the surface, it raises the GWR and the concentrations of ethane, propane, and butanes in the produced gas. This is the characteristic "bubble." If the reservoir were undersaturated such that the bottomhole pressure was above the bubble point, then the free gas phase would not have formed and the bubble phenomenon would not be seen.

This bubble of free gas is a temporary occurrence. Once a quasi-steady state is reached at the new bottomhole pressure, more gas will be differentially liberated from the brine and trapped further out in the reservoir. The net effect is a decrease in the GWR and in the concentrations of ethane, propane, and butanes relative to methane in the produced, predominantly solution gas. The GWR and the ethane, propane, and butane concentrations should fall below those of the previous lower flow rate. Our test is to monitor changes in the GWR's and ethane/methane, propane/methane, and butanes/methane ratios during various flow conditions.

Table 6 presents hydrocarbon ratios calculated from the flare line gas analyses presented in Table 1. Examination of these hydrocarbon ratios in relation to producing conditions and the "bubble" model produces the following observations:

- Although variations exist because of shut-in periods, the analyses of the three samples collected on August 10 provide ratios for a brine production rate of about 1400 BPD.
- The samples taken on August 11 were collected after producing 1.5 and 5.5 well volumes of fluid following increase of brine rate to more than 15,000 BPD. The higher ethane/methane and propane/methane ratios for the sample collected at 1840 hours are characteristic of the "bubble" due to production of free gas that had accumulated near the well bore during prior production at about 1400 BPD.

10/81

Table 6. HYDROCARBON RATIOS

<u>Date</u>	<u>Time</u>	<u>Ethane</u> <u>Methane</u> $\times 10^2$	<u>Propane</u> <u>Methane</u> $\times 10^3$	<u>Butanes</u> <u>Methane</u> $\times 10^3$
8-7-81	1045	1.95	4.4	0.8
8-7-81	1830	1.95	3.9	1.1
8-10-81	1220	1.87	3.7	0.7
8-11-81	1840	2.03	4.2	0.9
8-11-81	1937	1.92	3.9	0.6
8-12-81	1130	1.68	2.6	0.3
8-12-81	1420	1.58	2.6	0.3
8-12-81	1605	1.65	2.6	0.4

10/81

- The lower values of ratios for samples collected on August 12 are as expected due to gas liberation in the reservoir at the continuing high (>15,000 BPD) production rate.

These observations support the hypothesis that the reservoir brine is near saturation with gas. The evidence is not conclusive of saturation because of the following:

- Accurate GWR data are not available to support the hydrocarbon ratio changes.
- Whether or not a reservoir is saturated is best determined at the beginning of the well test. Previous flow tests only cloud the issue. Our results only indicate that the near well-bore bottomhole pressure during the low flow rate was below the reservoir bubble point. If the reservoir was slightly undersaturated, say by only 1000 psi, the evidence given in this test would be unchanged.
- Lack of the onsite laboratory caused difficulties in sampling and analysis. The lack of an onsite gas chromatograph is a serious handicap. The changes in composition that IGT looks for are small, and storage and transfer of the samples to IGT before analysis can only be detrimental to accuracy.

A copy of the report on recombination of samples collected on June 22, 1981, has been provided to IGT. Although validity of results is somewhat in question due to the reported low gas content of separator brine (0.9 SCF/STB vs. an expected 3.4 SCF/STB), errors due to this difference should be only about 10 percent at the extrapolated solubility of 34.3 SCF of separator gas at 15.025 psia and 60°F per bbl separator brine at 520 psig and 242°F.

Exhibit 4 provides a graphical comparison of actual recombination data points with values calculated using the algorithms of Haas (Ref. 9) and Blount (1981 version) (Ref. 7). The calculations are shown for salinities of both 166,500 mg/l and 116,900 mg/l. The higher value is the number for total dissolved solids (TDS) provided by Dr. Hankins of McNeese State University (Ref. 1) during a telephone conversation on August 5, 1981. The lower value is calculated sodium chloride content of brine based upon the Na⁺ concentration of 46,000 mg/l provided by Dr. Hankins during the same conversation.

Plots of this type for recombination of samples collected while producing the saturation GWR from low salinity Wells of Opportunity have consistently shown agreement within ± 3.0 SCF/STB for Weatherly Laboratory data points and values calculated using the two algorithms. This background makes it

Exhibit 4. COMPARISON OF RECOMBINATION DATA WITH CALCULATED GAS SOLUBILITY

hazardous to ignore the approximate agreement between recombinations and values calculated using 116,900 mg/l. It will be interesting to see what future, definitive work reveals for solubility under reservoir conditions in relation to the range of 31 to 34 SCF/STB representative of methane solubility in the NaCl content of produced brine and the lower (22 to 27 SCF/STB) range calculated using the TDS value 166,500 mg/l in the two algorithms.

III. Brine Chemistry Relevant to CO₂

Results of the minimal number of brine analyses performed by IGT were previously presented in Table 4. These results differ from our prior experience on Wells of Opportunity in that substantial differences in alkalinity, pH, and "acidity" (amount of NaOH required to produce a pH of 10) were observed from sample to sample. Comparison of IGT's data with analyses by Rice University, plus the complexity of inhibitor control on this well (Ref. 10), has led to the hypothesis that the observed variations in brine chemistry were largely due to undocumented variations in inhibitor concentration. The discussion below adds credibility to this hypothesis.

The analyses performed were alkalinity, "acidity," acid-liberated CO₂, pH, and calcium concentrations for each sample. The interactions between these and many other chemical species form a complex system. Calcium and carbonate combine to form scale and precipitate which subsequently affect all of the abovementioned parameters. Likewise, the inhibitors used (acetic acid and AMP-20, a phosphonate type inhibitor) change the pH, form complex calcium ions, and change bicarbonate to dissolved CO₂. The acidity, as described herein, is affected by the calcium concentrations through the formation of Ca(OH)₂, which then influences all the other parameters listed. A detailed investigation into the chemistry change is beyond the scope of this work, but one observation will be made.

The alkalinity and the pH are both strongly tied to the amount of inhibitor, primarily acetic acid, injected into the brine. The amount of acetic acid nominally added is comparable to the alkalinity of reservoir brine on a molar basis. The acetic acid probably almost completely dissociates into the hydronium (H⁺) ion and the acetate ion, because the acetate is complexed with the Ca⁺⁺ ions. The H⁺ ions react with bicarbonate to form water and dissolved CO₂ as follows:

The close relation between pH and alkalinity is plotted in Exhibit 5. Note that a log scale is used on the x-axis, and pH, which may be defined as the negative log of the hydronium ion concentration, is on a linear scale. The concentration of inhibitor appears to be a primary cause of change of both the pH and the alkalinity.

It is possible that precipitation of $CaCO_3$ is another reason for the decrease in alkalinity from 300 to 150 $mg\ HCO_3^-/l$ when flow rate was increased from about 1400 to over 15,000 BPD. If the concentration of inhibitor in supply tanks was not simultaneously increased, the higher brine rate may have diluted the inhibitor to below the threshold for effectiveness (Ref. 10).

Assuming precipitation of $CaCO_3$ from the brine is described by the reaction

a decrease of 150 $mg\ HCO_3^-/l$ in alkalinity would produce 124 mg/l of $CaCO_3$ and 54 mg/l of CO_2 . In more familiar units, these values correspond to 43 pounds of calcite per 1000 bbl of brine and 0.16 SCF CO_2 /bbl of brine. Such production of calcite and CO_2 would probably not have been detected.

Conclusions

The major conclusions from IGT's work reported herein are —

- Reservoir brine is probably at or near saturation with natural gas.
- At the times of sample collection by IGT, partitioning of gaseous species between the gas and brine outputs of the separator was reasonably consistent with that from separators used on Wells of Opportunity tested by Eaton Operating Company and the separators used for the 1980 testing of the Pleasant Bayou Well No. 2.
- Total CO_2 content of produced brine, including bicarbonate ions and carbonate precipitates, is lower than experienced on Wells of Opportunity, as would be expected due to the high Ca^{++} content of produced brine.
- Partitioning of CO_2 between the gas output of the separator, CO_2 in solution in brine to the disposal well, bicarbonate ions in brine to the disposal well and $CaCO_3$ precipitates is dependent upon details of inhibitor injection in relation to separator pressure and temperature.
- Solids retrieved from below perforations in the production well contained about 7 percent by weight plastic lining from the production casing and about 6.5 percent by weight carbonates and other salts soluble in 1N HCl.

Exhibit 5. RELATIONSHIP BETWEEN ALKALINITY
AND THE BRINE pH

10/81

The major significance of the IGT work reported herein is the suggestion that reservoir brine may well be at or near saturation with natural gas. At the same time, this result is not definitive due to lack of precision, time dependent metering of gas and brine flow rates required to establish correlation of changes in total produced gas/brine ratio with the observed changes in chemical composition of produced gas.

The above conclusion regarding partitioning of gaseous species between separator outputs was qualified as "reasonably consistent" with prior experience. This qualification is due to a) lack of an onsite gas chromatograph and hardware for prompt acid liberation of CO₂ from separator brine samples, b) the discrepancy between quantities of gas liberated from brine samples in the field vs. samples analyzed later in IGT's Chicago laboratory, and c) the change of 70 psi in separator pressure provided to IGT on the basis of calibration of the pressure gauge several days after collection of IGT's last sample.

Comparison of recombination data by Weatherly Laboratories with expectations from laboratory studies of methane solubility in brine, in the context of prior similar comparisons for Wells of Opportunity, provided a surprising result: Namely, the recombination data points agreed with solubility calculated on the basis of only the NaCl content of produced brine. Differences at actual data points were a maximum of about 3 SCF/STB and consistent with differences observed on Wells of Opportunity. In contrast, expected gas solubility assuming total dissolved solids are equivalent to that weight of NaCl is less than the recombination measurement at 10,270 psia by 7 to 11 SCF/STB.

During mid August, operator installation of a positive displacement meter and changes in the orifice meter run resulted in about doubling reported gas production rates. However, it is IGT's judgment that accuracy of gas and brine rate measurements is not yet adequate to warrant a conclusion regarding actual produced gas/brine ratio in comparison with the values of 23 to 27 SCF/STB calculated on the basis of 166,500 mg/l of dissolved solids and the range of 31 to 35 SCF/STB calculated from the 117,000 mg/l NaCl content and extrapolated from recombination studies.

Recommendations

The MG-T/DOE Amoco Fee No. 1 Well has demonstrated over 250,000 bbl of brine production without buildup of injection pressure on the disposal well. This is in sharp contrast to prior well tests performed as a part of DOE's Geopressured-Geothermal Program and is very encouraging in the context of low operating cost for energy production.

The major uncertainty in cost of energy production from this well is the ratio of produced gas to produced brine. It is therefore recommended that effort be concentrated upon modifications of surface hardware, metering and procedures for fluid analyses, plus data interpretation to determine this ratio.

The most significant recommended hardware and metering changes are —

- Addition of an air cooler and small separator between the present separator and the orifice meter to remove water vapor
- Use of an orifice meter run that meets ANSI standards for natural gas metering and permits change of orifice size without disruption of flow
- Addition of a brine metering skid after the main separator which permits turbine calibration and change of turbine size without disruption of flow
- Adding 100 percent redundant instrumentation capable of 1-day turnaround in calculating gas/brine ratio in terms of SCF/STB with 1/2 hour or less time resolution.

After the recommended hardware and metering changes have been implemented, it is recommended that field operating procedures be tailored to providing definitive conclusions regarding gas/brine ratio and whether reservoir brine is saturated with natural gas. Specific recommended procedural steps are —

- Produce the well at a constant rate of 2000 to 2500 BPD until flow metering and fluid sample analyses reveal that a steady state condition has been achieved. Fluid sampling and analysis would consist of simultaneously collecting separator output gas and brine samples in pressure cylinders and then promptly analyzing these on location to determine
 - composition of flare line gas
 - quantities of liquids from the small separator in relation to gas or brine production
 - quantity and composition of gas liberated by pressure reduction to 1 atmosphere after cooling liquid samples to ambient temperature

- quantity of CO_2 liberated by acid plus alkalinity of brine after gas liberation to 1 atmosphere pressure.

Inhibitor concentration in surface brine must also be constant and known.

- Perform stepwise variations in separator pressure between lowest practicable value and 1000 psi. Analyze suites of samples at each pressure and combine with flow meter data to calculate total produced hydrocarbons and CO_2 . Do not proceed until total gas/brine ratio for each gaseous species is found to be independent of separator pressure.
- Collect separator gas and brine samples for recombination studies and comprehensive chemical analysis.
- With production rate still constant, change to an orifice plate and a turbine as appropriate to accurate flow metering at a brine rate of 15,000 to 20,000 BPD.
- Increase brine rate to 15,000 to 20,000 BPD during a 30-second time interval. Collect suites of samples at roughly 1.5, 3, 5, and 10 times the time required for fluid transit from perforations to the wellhead. Exact times of sampling should be adjusted to provide samples at maxima and minima in orifice differential pressure. Analysis of these samples will reveal whether free gas production contributes to any observed fluctuations in gas/brine ratio. Inhibitor injection rate must be simultaneously increased to maintain constant concentrations.
- Maintain constant producing conditions until rate metering and sample analyses again clearly reveal steady-state operation.
- If steady-state values of gas/brine ratio or composition of total produced gas differ from those at the lower rate, repeat the variation of separator pressure to verify material balance and repeat sampling for recombination studies and comprehensive chemical analyses.
- Reduce brine rate back to 2000 to 2500 BPD with all procedures similar to those before, during, and after the previous rate increase.
- If analysis of data from the above steps does not reveal consistency between field data and laboratory recombination studies, iterate the above steps with changes in details until such consistency is achieved.

If the bubble point of reservoir brine exceeds the lowest bottomhole pressure previously experienced during testing of this well, the above steps in production rate will be accompanied by interpretable changes in both gas/brine ratio and chemical composition of produced gas. On the other hand, if no changes in gas/brine ratio or gas composition are observed, it will be clear that the initial bubble point in the reservoir was lower than the bottomhole pressure experienced at the rate of 15,000 to 20,000 BPD. If this latter situation is experienced, the additional step of production at maximum possible rate may warrant similar detailed analysis.

Completion of the actions recommended above should provide a basis of understanding warranting a major reduction in operating costs. Rate metering would be automated with sufficient redundancy to catch discrepancies. Daily calculation of gas/brine ratio would continue until larger time intervals were clearly warranted. Fluid sampling interval would be increased until sampling was only in response to observed changes in gas/brine ratio or other producing characteristics (e.g., scaling, injection pressure increase, anomalous rates, or anomalous pressures).

The understanding of producing characteristics from the above recommended steps, in conjunction with results of reservoir engineering analysis, would provide firm technical basis for engineering evaluation, cost estimates, and decisions regarding gas cleanup and sale.

10/81

ACKNOWLEDGMENTS

The authors are grateful for the cooperation and information provided by the organizations performing this well test, which include Magma Gulf-Technadril, Weatherly Laboratories, McNeese State University, and Rice Engineering Design and Development Institute of Rice University. Of particular importance was the cooperation and assistance given in the field by Larry Durrett and Jonne Berning, which helped make this study possible and meaningful. Portions of this work were performed under Department of Energy Contract No. DE-AC08-78ET27098 titled "Computer Simulation of Production From Geopressured-Geothermal Aquifers," Gas Research Institute Contract No. 5011-321-0140 titled "Gas Saturation in Formation Waters," and Magma Gulf-Technadril P. O. No. 1577.

93(3000)/65036MG-T

REFERENCES

1. Hankins, B. E., McNeese State University, Lake Charles, Louisiana, Private Communication, 1981.
2. Neal, J., "Reservoir Fluid Analysis for Magma Gulf-Technadril Amoco Fee Well No. 1," Weatherly Laboratories, Inc., Lafayette, Louisiana, 1981.
3. Weatherly Laboratories, Inc., Data files on location, 1981.
4. Garg, S. K. et al., "Geopressured Geothermal Reservoir and Well Bore Simulation," Final Report (Year 2) SSS-R-78-3639. Systems Science and Software, La Jolla, Calif., 1981.
5. Culberson, O. L. and McKetta, J. J., "Phase Equilibria in Hydrocarbon Water Systems, III, Solubility of Methane in Water at Pressures in Excess of 10,000 psia," Trans. AIME 192 (1951), 223-26.
6. Eaton Operating Co., "Testing Geopressured-Geothermal Reservoirs in Existing Wells, Final Report, HO&M Prairie Canal Co. Well No. 1," Department of Energy Contract No. DE-AC08-80ET27081 (to be published).
7. Idaho State University, "Solubility of Methane in Waters From Pleasant Bayou Well No. 2," Report for Institute of Gas Technology under P.O. No. S542544, Idaho State University, Pocatello, 1981.
8. Randolph, P. L., and Rockar, E. M., "Do We Know Whether the Pleasant Bayou #2 is Saturated With Methane?" IGT Technical Report, Institute of Gas Technology, Chicago, Illinois, 1981.
9. Haas, J. L., Open File Report No. 78-1004. U.S. Department of the Interior, Geological Survey, Reston, Va., n.d.
10. Oddo, J. E. and Thomson, M. B., "Scale and Corrosion Report for the Magma Gulf-Technadril Amoco Fee #1 Design Well," Rice Engineering Design and Development Institute, Rice University, 1981.
11. Eaton Operating Company, "Testing Geopressured-Geothermal Reservoirs in Existing Wells, Final Report, Riddle-Saldana Well No. 2," Vol. II, Well Test Data, Department of Energy Contract No. DE-AC08-80ET27081 (to be published).

APPENDIX C.

IGT Testing Activities on the Leroy Sweezy #1 Well
During September 1982

C-1/2

IGT TESTING ACTIVITIES ON THE
Leroy Sweezy #1 Well During
September 1982

Christopher G. Hayden
Mark G. Doherty

Institute of Gas Technology
3424 South State Street
Chicago, Illinois 60616

IGT Project Report 61025

During September and October 1982, IGT personnel collected and analyzed samples of gas, brine, and liquid hydrocarbons from the separator during testing of the DOW Chemical USA/DOE Lee Roy Sweezy #1 well. IGT obtained from the well operators and various subcontractors production and analytical data that encompassed the entire flow test to date. This report addresses three questions:

- What is the quantity and composition of the gas leaving the separator dissolved in the disposal brine?
- Is the reservoir brine saturated with gas?
- Was the produced oil in solution in the brine at reservoir conditions?

Achieving meaningful conclusions on these subjects has required substantial departures from the sampling schedule and sample handling procedures prescribed in the procedures manual for geopressured fluids developed for DOE (Ref. 1). For this reason, the procedures used and results of analyses performed are described here in considerable detail. Discussion of addressing the above three questions are presented with the data. Conclusions and recommendations are summarized in the last sections of this report.

Background

Results of chemical analyses and calculated production rates, pressures, and other pertinent data were provided by DOW Chemical, its contractors and the program administrators. Brine analyses are performed regularly and rather thoroughly.

Tables of values reporting monthly averages showed little change over the flow test, excluding the well documented changes in zinc. No analysis was performed on the quantity and the composition of gas remaining in the disposal brine. Also, no "total carbon dioxide" values were determined.

Numerous flare line gas analysis results were received from Dr. Dean Keeley of the University of Southwestern Louisiana. These are presented in Table 1. These data will be examined in later discussions to help us determine the degree of saturation of this reservoir.

Table 1. GAS COMPOSITION DATA OBTAINED FROM
UNIVERSITY OF SOUTHWESTERN LOUISIANA, MOLE %

<u>Date</u>	<u>Nitrogen</u>	<u>Carbon Dioxide</u>	<u>Methane</u>	<u>Ethane</u>	<u>Propane</u>	<u>Butanes</u> ¹	<u>Pentanes</u> ¹
5-12-82	0.43	2.79	93.82	2.46	0.36	0.14	0.01
5-13-82	0.42	2.70	93.81	2.46	0.36	0.13	0.01
5-18-82	0.48	2.77	93.77	2.46	0.37	0.14	0.01
5-20-82	0.50	2.65	93.87	2.48	0.37	0.11	0.01
6-8-82	0.39	2.54	93.94	2.48	0.38	0.16	0.02
6-11-82	0.35	2.37	94.29	2.48	0.37 ₂	0.12	0.01
6-14-82	0.36	2.54	93.60	2.53	0.83 ₂	0.13	0.01
6-17-82	0.36	2.42	94.30	2.48	0.31	0.12	0.01
6-21-82	0.35	2.44	94.27	2.49	0.32	0.12	0.01
6-25-82	0.51	2.41	94.12	2.47	0.37	0.12	0.01
7-7-82	0.42	2.49	94.18	2.45	0.31	0.13	0.01
7-16-82	0.37	2.56	94.17	2.45	0.31	0.12	0.01
7-28-82	0.36	2.48	94.24	2.46	0.31	0.12	0.01
8-5-82	0.42	2.45	94.18	2.45	0.36	0.12	0.00
8-16-82	0.39	2.49	94.22	2.47	0.31	0.12	0.00
8-23-82	0.37	2.47	94.25	2.47	0.31	0.12	0.01
9-1-82	0.32	2.38	94.33	2.48	0.31	0.12	0.01
9-20-82	0.40	2.40	94.28	2.47	0.31	0.12	0.01

-
1. The sum of the normal and the iso-butane and pentane concentration. are reported here.
 2. Dr. Dean Keeley, University of Southwestern Louisiana, believes this is probably a bad analysis.

This reservoir has also produced small quantities of liquid hydrocarbons. There has been several analyses of various fractions of this "oil," but no comprehensive review of the total produced oil was available.

IGT Sampling Procedures for Gas and Brine

IGT has developed sampling and analysis procedures on Wells of Opportunity tests to accurately measure the total gas production from a geopressured geothermal well. These procedures were modified to compensate for the lack of an onsite gas chromatography and an acid liberation-nitrogen purge carbonate train. Emphasis was placed on collecting both brine and gas samples and performing a hydrogen sulfide analysis in 15 minutes. Brine and gas samples are collected in as short a time as possible to minimize the chance that any change in conditions (flowing or compositional) will occur during the sampling procedure. Hydrogen sulfide instability necessitates rapid analysis for accurate results, although on this well hydrogen sulfide compositions were below the minimum detectable limit of 1 ppm.

- Flare line gas samples were caught in preheated Teflon-lined stainless steel sample cylinders. The cylinders were preheated to above 100°C to minimize water condensation within the sample vessel. The closed valve ends were fitted with Swagelok caps to prevent leaks, and the sample was shipped to IGT for analysis.
- The gas samples were heated at IGT to a temperature greater than 100°C and analyzed using a mass spectrometer.
- Draeger hydrogen sulfide analyses of the flare line gas samples were performed using procedures outlined in Gas Processors Association's Tentative Method of Test for Hydrogen Sulfide in Natural Gas Using Length of Stain Tubes.
- Brine samples were caught in Teflon-lined stainless steel pressure vessels at separator pressure and temperature. The closed valve ends were sealed with Swagelok caps and quickly cooled by immersion into a cold water bath. The samples were then shipped to IGT for analysis, although one was partially analyzed in the field and then discarded.
- The brine analysis consisted of several steps. The first was to reduce pressure on the cooled brine to 1 atmosphere by using a large syringe. The syringe was connected to the cylinder valve and the valve opened. The exsolved gas pushed the plunger in the syringe. After the cylinder was struck several times to enhance gas dissolution, the gas volume was read directly off the syringe. The brine was emptied into a graduated cylinder and its volume noted. At this point the field sample was discarded.

Several more analytical steps were performed on samples shipped to IGT as follows:

- The gas was analyzed using a mass spectrometer.
- The brine was divided into two portions and measured. The first portion was immediately treated with sodium hydroxide to stabilize the CO_2 in solution (going to a pH of ~ 10). The second portion of the sample was untreated.
- A representative sample of the alkaline brine was treated with acid and purged with nitrogen, quantitatively trapping and measuring the exsolved CO_2 . This procedure measures "total CO_2 ," which includes dissolved CO_2 , bicarbonate, and carbonate species.
- A portion of the untreated brine was titrated with sulfuric acid to determine alkalinity.

In addition to these standard sampling procedures, new techniques and procedures were employed to quantify the amount of oil produced. This involved determining the amount of oil contained in the flare line gas and the amount remaining in the brine leaving the separator. The apparatus used to determine the quantity of oil in the flare line gas was designed, set-up, and operated by DOW Chemical and its contractors. This apparatus was used to freeze liquid hydrocarbons out of a portion of the flare line gas as follows.

- Flare line gas leaving the separator passes through an orifice meter run, a back pressure control valve, a small liquid knockout, a positive displacement meter, and about 40 feet of pipe before reaching the extraction facility.
- The gas flows through a cold trap at 0°C and then through two sequential traps immersed in dry ice and acetone (-78°C).
- The gas flow rate through these traps was kept below $0.3 \text{ ft}^3/\text{minute}$ to allow the gas to cool sufficiently. The gas flow rate and the total amount of gas passing through the trap was measured using a small wet test meter.
- All liquid caught in the first trap in the water bath was discarded. The two dry ice acetone bath traps were warmed to room temperature and washed with methylene chloride. This methylene chloride was then sealed and shipped to IGT for analysis.
- At IGT, the sample was treated with a control standard of normal octane and the quantity and composition of the oil in the methylene chloride was determined by capillary gas chromatography using a Finnigan MAT Model 4510 Gas Chromatograph/Mass Spectrometer.

The collection of liquid hydrocarbons from the brine phase was performed using the two extraction techniques. The first involved passing the hot brine

from the separator through a C₁₈ Sep Pac cartridge. This cartridge contains a C₁₈ hydrocarbon bonded to a solid base. The liquid hydrocarbons are extracted on to the C₁₈ coating and remain there until another hydrocarbon solvent is used to elute them. Three cartridges had 500 ml, 1000 ml, and 1500 ml of hot brine passed through them, respectively. But when the hydrocarbons were eluted, the cartridges were found to hold 1.5 mg, 1.7 mg, and 1.7 mg, respectively of oil. We can only conclude that the smallest brine sample (500 ml) probably contained a sufficient amount of oil to saturate the cartridge. For this reason, although the eluted oils were analyzed by capillary column gas chromatography, the analysis was halted before identification of compounds to save money. The chromatograms are included in the appendix of the report, but no compositional data is presented.

The second technique employed by IGT personnel to extract liquid hydrocarbons from the brine had considerably more success. The procedure is listed below:

- A 5 foot long piece of teflon tubing was connected to a sampling valve at the brine outlet of the separator.
- Large quantities (>3 gallons) were flowed through this valve and tubing to flush out the system and to ensure a fresh, representative brine sample is caught.
- The valve is barely cracked open, and is closely monitored from that point on, to ensure that the brine flow rate does not exceed about 30 ml/minute.
- The outlet end of the teflon tube was placed into a 2 liter separatory funnel kept cool in a large ice bath. The funnel contained about 30 ml of methylene chloride.
- The hot brine bubbled directly through the methylene chloride, causing turbulence and enhancing the extraction process.
- After filling the separatory funnel, it was sealed and agitated. The methylene chloride was then removed.
- An additional 20 ml of fresh methylene chloride was added to the brine. The mixture was again agitated, and the methylene chloride phase was removed and combined with that from the first extraction. This methylene chloride was then sealed and shipped to IGT for analysis. The brine, which probably still contained trace organic acids, was discarded.
- The methylene chloride was then treated with a standard and concentrated.
- This concentrate was analyzed by capillary column gas chromatography/mass spectrometry. The results are presented in the Appendix.

Results of Analyses

IGT performed several types of analyses to help define hydrocarbon production from this reservoir. Table 2 contains the results of our mass spectrometry analysis of the gas from the top of the separator, an analysis of "wellhead gas" performed by Lawrence Berkeley Laboratories, and the average values reported by the University of Southwestern Louisiana. Separator pressure was read off existing gauges.

Table 3 contains the results of analysis of brine leaving the separator for dissolved gas. The column titled Total CO₂ contains the total quantity of carbon dioxide exsolved from the brine at ambient conditions after acidifying the sample and bubbling nitrogen through it. Substantial quantities of the carbon dioxide may have been in various carbonate forms. An alkalinity titration revealed ~730 mg/l equivalent as HCO₃⁻, which would contain more carbon dioxide than was measured using the acid liberation-nitrogen purge technique. These data suggest that other organic salts in addition to carbonate species are contributing to the alkalinity content of the brine.

Table 4 presents condensed results of all liquid hydrocarbon analyses. Detailed results are in the Appendix. Oil collected from the flare line cold traps was related to the quantity produced with the brine using a flare line gas value of 16 SCF per barrel of brine as representative of the gas production at the time of sampling.

Discussion

The three objectives that this study set out to answer were:

- To determine the quantity and composition of the gas leaving the separator dissolved in the disposal brine.
- To determine whether the reservoir is saturated with gas.
- To determine whether the liquid hydrocarbon phase may be dissolved in the brine at the reservoir conditions.

The discussion of our results and conclusions is presented by treating each of these topics in a separate section.

I. Quantity and Composition of Gas Remaining in the Disposal Brine

At high separator pressures, substantial quantities of gas remain dissolved in post separator brine. The amount of hydrocarbons remaining in the brine is primarily dependent upon the partial pressure of the hydrocarbons

Table 2. GAS ANALYSES RESULTS FROM SEVERAL PARTIES

Date Laboratory	Sept. 23, '82 IGT	Sept. 24, '82 IGT	Sept. '82 USL	Aug. 12, '82 LBL
Nitrogen	0.12	0.08	0.38*	0.3
Car. Dioxide	1.80	1.65	2.39	2.0
Methane	95.61	95.93	94.29	95.1
Ethane	1.95	1.93	2.48	2.0
Propane	0.32	0.30	0.33	0.24
n-Butane	0.11	0.03	0.03	0.12**
i-Butane	0.06	0.07	0.09	—
Pentanes	0.00	0.00	0.01	—
Benzene	0.02	0.01	—	0.009
Tolulene	0.01	0.00	—	0.006
Xylene	0.00	0.00	—	0.004
Water	—	—	—	0.5

* Includes any air, if present.

** Only total butanes were reported.

Table 3. IGT RESULTS OF GAS LIBERATED
FROM BRINE AFTER THE SEPARATOR

<u>Date</u>	<u>9/22/82</u>	<u>9/23/82</u>
Separator pressure (psig)	660	660
Brine temperature (F)	207	208
Liberated GWR (^{Scf} /STB)	3.78	3.82
Additional Carbon Dioxide (^{Scf} /STB)	1.36	1.51
Composition (Mole Fraction) of the liberated gas		
Nitrogen	.0072	.0029
Carbon Dioxide	.0608	.0680
Methane	.9163	.9130
Ethane	.0136	.0136
Propane	.0014	.0016
n-Butane	.0001	.0001
i-Butane	.0002	.0002
Pentanes	.0000	.0000
Benzene	.0002	.0002
Toluene	.0001	.0001

Table 4. SUMMARY OF IGT LIQUID HYDROCARBON ANALYSES

Sample Type	Flare Line Trap	Liquid Extraction #1	Liquid Extraction #2
'Oil' to Brine Ratio (mg/l)	1.0	4.3	5.2
Composition (weight percent)			
Aliphatic Hydrocarbons C ₅ - C ₈	7.2	<0.3	<0.4
C ₉ - C ₁₂	0.7	<0.3	<0.4
C ₁₃ ⁺	0.2	<0.3	19.4*
Aromatic Hydrocarbons Benzene	20.7	41.2	35.0
Methyl Benzene	22.7	21.0	17.7
C ₂ Benzenes	23.5	11.4	9.6
C ₃ ⁺ Benzenes	11.8	3.1	2.9
Indan	0.1	—	—
C ₂ Indans	0.14	—	—
C ₃ ⁺ Indans	0.07	—	—
Naphthalene	2.7	6.6	5.1
Methyl Naphthalene	2.8	3.7	2.7
C ₂ Napthalenes	1.8	1.5	1.2
C ₃ Napthalenes	0.5	—	<0.1
Biphenyl	0.44	0.5	0.4
Methyl Biphenyl	0.22	—	—
Phenols	—	5.3	3.9
Dibenzo Furans	0.08	—	—
Unidentified	4.3	5.7	2.1

* Probably grease contamination — a different stopcock grease was used during this extraction.

in the gas phase (Hayden and Randolph). Figure 1 compares the quantity of methane in the disposal brine versus the partial pressure of methane in the separator for several wells. Results of analyses from this well are consistent with data from other wells. At the separator pressure of 600 psi, about 3600 BTU/bbl or about 3.8 SCF/bbl of total gas is lost in the disposal brine.

II. Is the Reservoir Saturated With Gas?

In the absence of comprehensive GWR and recombination data, reservoir saturation may be qualitatively inferred by examining produced hydrocarbons. The tests involve examining the quantities and ratios of various hydrocarbon species versus producing conditions. Fundamentals basic to the tests are listed below:

- Critical Gas Saturation

A sandstone reservoir consists of an immense number of tiny pores between sand grains. These are in turn connected by a three-dimensional maze of pore throats. Both the pores and the pore throats have a broad distribution of sizes.

If most of the total pore volume in the reservoir is water-filled but a very small amount of gas is present, only water will flow under an applied pressure gradient. This is because water wets the rock surface and provides the continuous fluid phase. In contrast, surface tension will keep the gas in minute bubbles contained within some of the individual pores. If these minute bubbles are larger than pore throats, they will impede the flow of water but will not be able to pass through the pore throats. However, if the fraction of pore volume that is gas-filled is sufficiently large for the gas bubbles to coalesce and to form a continuous gaseous phase through a tortuous path of pore throats, gas will also move in response in an applied pressure gradient. The percentage of pore volume that must be occupied by gas before the bubbles coalesce is the critical gas saturation. Although definitive measurements have not been reported for the critical gas saturation relevant to geopressured aquifers, it is generally assumed to be in the range of 2% to 3% of the pore volume. If a reservoir is near the critical gas saturation, then bubble expansion resulting from decreasing pressure in the reservoir during drawdown may well allow bubbles to coalesce and flow.

Figure 1. METHANE SOLUBILITY IN DISPOSAL BRINE

- Bubble Point Pressure

Figure 2 is a plot of methane solubility vs. reservoir pressure calculated for a temperature of 300°F and a salinity of 10,000 mg/l using the equations of Price et al. (1981). The initial reservoir pressure is 9000 psi. The assumed hydrostatic pressure of 4200 psi is consistent with field data on pressure gradients after heating of the wellbore by production from the reservoir. The "bubble point" is simply the pressure corresponding to the amount of gas in solution in the brine. If a reservoir is initially saturated with methane, the bubble point will be at the pressure of 9000 psi illustrated as point A in Figure 2 corresponding to about 44.8 SCF/STB.

In this case, any pressure drop due to production will reduce pressure to below the bubble point. As a result, a portion of dissolved gas will be released to reservoir pores as tiny gas bubbles. If critical gas saturation is not achieved, that gas will remain trapped reducing the gas content of the produced brine toward that corresponding to bottomhole pressure in the wellbore. Thus, gas content of produced brine should become lower as bottomhole pressure is decreased to provide higher flow rates. In contrast, if the initial gas content of reservoir brine is so low that the bubble point is at hydrostatic pressure (point B in Figure 2), gas content of produced brine will be independent of bottomhole pressure for brine production without pumping. Further, that gas content will remain equal to gas solubility at the bubble point pressure. There would be no accumulation of gas in pore in the reservoir and no variation in produced GWR.

It was often assumed that depletion of an initially saturated reservoir (bubble point A) by production until reservoir pressure uniformly reduced to hydrostatic pressure would not result in critical gas saturation. For the hypothetical case in Figure 2, such depletion would release 15.4 SCF/STB of natural gas. Assuming an ideal gas at the abandonment hydrostatic pressure of 4200 psi, this gas would occupy only 0.014 barrels per barrel of reservoir pore volume. This gas saturation of 1.4% is below the widely assume value to 2% to 3% for critical gas saturation. This behavior was recognized during the original Louisiana State University (LSU) assessment of Louisiana potential of aquifers not containing a free gas phase for the DOE program (Hawkins, 1977). That study assumed that the gas content of produced brine would be the average of saturation at the original reservoir and hydrostatic pressures.

HYPOTHETICAL RESERVOIR

Figure 2. METHANE SOLUBILITY FOR HYPOTHETICAL RESERVOIR

Initial production from an aquifer containing brine that is saturated with natural gas provides a mechanism for achieving critical gas saturation in the immediate vicinity of the producing wellbore. This mechanism is the liberation of gas in the pressure gradient region. During production, a large volume of fluid passes through this region so that accumulation of gas can reach critical gas saturation. Implications of this phenomenon will be further discussed below under the subheadings "Variation of Composition of Gas Liberated as Pressure is Reduced" and "Reservoir Phenomenology."

— Variation of Composition of Gas Liberated as Pressure is Reduced

The above discussion was in the content of pure methane. However, methane is but one of several constituents of natural gas produced from aquifers. Further, pressure dependence of solubility varies for the different constituents of a real natural gas. Typical abundances of various constituents and the change in relative amounts liberated by pressure reduction are illustrated in Table 5. This table presents data from differential liberation measurements performed after recombining samples of separator gas and separator brine to a bubble point at reservoir pressure and temperature for the Riddle-Saldana No. 2 Well.⁽⁶⁾ The work was performed by Weatherly Laboratories Inc. Results of differential liberation studies from other Wells of Opportunity had been similar in relation to variations in composition of gas liberated for successive steps in pressure reduction.

Note that the gas liberated in the first pressure reduction (6632 to 4000 psia) contained a much lower fraction of CO₂ and much higher fractions of ethane through hexane hydrocarbons than gas liberated in subsequent pressure steps. This variation in gas composition with pressure is important for deducing whether brine in the tested reservoir was saturated with natural gas.

— Reservoir Phenomenology

Combining the above qualitative concepts to conclude whether a reservoir is saturated with natural gas involves recognition of characteristics of gas/brine ratio and composition of produced gas in relation to producing conditions. These characteristics are discussed below for a reservoir that is originally saturated with gas.

Establishing a brine rate will cause a pressure drop around the wellbore. The produced GWR and the ratios of ethane/methane, propane/methane, and

Table 5. COMPOSITIONS OF GAS RELEASED FROM BRINE BY DIFFERENTIAL
LIBERATION, RIDDLE-SALDANA WELL NO. 2

Pressure Step, psia	6632-4000	4000-2500	2500-1000	1000-25
Total Gas, SCF/STB	6.8	7.7	10.8	17.0
Gas Composition, mole %				
CO ₂	1.80	3.05	8.76	18.64
Methane	92.24	92.74	88.46	79.18
Ethane	4.43	3.44	2.44	1.85
Propane	0.96	0.54	0.26	0.10
n-Butane	0.19	0.07	0.02	0.01
i-Butane	0.18	0.08	0.02	0.03
n-Pentane	0.08	0.02	0.01	0.01
i-Pentane	0.05	0.01	0.01	0.01
Hexanes	0.03	0.01	0.01	0.01
Heptanes+	0.04	0.05	0.02	0.19

butanes/methane would initially represent the gas originally present in solution. As the pressure around the wellbore decreases, some of the gas in solution will be differentially liberated from the brine. This gas would probably be trapped in the reservoir pore space until critical gas saturation is reached, and then small amounts would be coproduced with the brine. The overall GWR and the produced ethane/methane, propane/methane, and butanes/methane ratios would continually decrease as the bottomhole pressure decreases, and more gas is liberated and trapped in the reservoir. The produced hydrocarbon ratios and GWR will be lower than originally present in the reservoir, but with a small quantity of the exsolved gas also being produced, will be above the solubility at the bottomhole pressure.

If, on the other hand, the reservoir was undersaturated with respect to the bottomhole pressure, no gas will be liberated from the brine. The produced GWR and the ratios of ethane, propane, and butanes to methane would be unchanged. As the bottomhole pressure finally goes below the bubble point pressure of the brine, gas will be liberated from the brine and will be trapped in the pore space. The gas chemistry behavior would then be similar to a reservoir originally saturated.

Examining the flare line gas composition data obtained from the University of Southwestern Louisiana (Table 1), we note that the propane/methane ratio dropped from an average of $.39 \times 10^{-2}$ to an average of $.34 \times 10^{-2}$ between 6-11-82 and 6-17-82. The 6-14-82 analysis has been disregarded as poor data, as suggested by Dr. Dean Keeley of the University of Southwestern Louisiana. Similarly, the butanes/methane ratio dropped from an average of 1.5×10^{-3} to 1.3×10^{-3} on or about 6-11-82. The ethane/methane ratios did not appreciably change during this entire test. However, the propane/methane and the butanes/methane ratios are much more sensitive to losses of small quantities of liberated gas than the ethane/methane ratios. We must, therefore, assume in the absence of additional data that the decreases in the propane and butane to methane ratios are real, and are caused by the liberation of small amounts of propane and butanes rich gas from the brine in the reservoir. Subsequently, we conclude that the bottomhole pressure must be below the original reservoir bubble point pressure. The bottomhole pressure, as estimated from graphs provided by DOW Chemical, was between 10,200 psi and 10,600 psi. This would indicate that the reservoir brine was undersaturated by about 1000 psi, or that supersaturation or some other phenomenon occurred which kept us from

observing the changes earlier. If, on the other hand, the flowing bottomhole pressure was not lowered below the reservoir bubble point pressure, than no gas would have been liberated from the brine in the reservoir. The produced GWR and the ratios of methane, propane, and butanes to methane would remain unchanged. If this is the case, the compositional changes observed would be attributed to sample collection or analytical changes. This possibility can not be ruled out. The ethane/methane ratios, which are easy to measure accurately, did not change by more than 1/2 of one percent during the test for any significant length of time. There is also considerably more scatter in the propane values than IGT is accustomed to seeing in Wells of Opportunity tests. If the thirteen percent change in the propane/ methane ratio, and the eleven percent change in the butanes/methane ratios are not real, than the reservoir brine is undersaturated even at the flowing bottomhole pressure. Our assessment, based on the available data, is that the reservoir brine is undersaturated with gas by as little as 1000 psi. Based on the work of Price et al and Haas we would have expected about 27 Scf/bbl of methane in solution. However, this figure is for a pure methane-brine system and not for what was encountered in this reservoir. The presence of heavier hydrocarbon species could depress methane solubility so that the approximate 20 SCF/bbl noted from the flare line and gas in the disposal brine could constitute a slightly undersaturated condition.

There is substantial quantities of oil dissolved in the brine, and it is not unreasonable to suspect that free hydrocarbon accumulations may exist somewhere in the reservoir. If this is the case, the brine could well be in contact with this gas condensate or oil phase and appear undersaturated with gas due to the depression of gas solubility.

Representatives of Lawrence Berkeley Laboratories also obtained samples from this well and drew conclusions on the degree of saturation of the reservoir brine. They stated, in a Quarterly Report to the Gas Research Institute (Weres, 1982), that the Parc Perdue well apparently produces from a free gas cap. Their assertion is that the distribution of hydrocarbons suggest that a gas cap was formed by the drawdown of the reservoir pressure due to production. Finally, they postulated that this gas cap exists just above the perforations and occasionally would be coned in for short periods of time. We tentatively agree that there is the possibility of free gas forming in the pore structure but disagree with gas migration and their other inferences.

The champagne production model, where in dropping the reservoir pressure causes gas to come out of solution and migrate up to form a gas cap which is then produced, no longer is considered a viable mechanism for gas production from aquifers. It is possible that the liberated gas can be produced intermittently with the brine, but the shape of the GWR curve and the natural gas liquids/methane ratios would differ significantly from what has been observed on this well. The only observation given in the LBL report to support their contention is that:

"The color of the gas flare at the Parc Perdue well fluctuates; occasionally, it temporarily becomes bright orange and very sooty, indicating a large, temporary increase in the concentration of aromatic hydrocarbons. This probably indicates episodes of gas production from the free gas phase.

We agree that the flare appears to occasionally turn orange and somewhat sooty. This is believed to be caused primarily by the aromatic heavy hydrocarbons. The source of these hydrocarbons, however, is not free gas coning into the wellbore from the reservoir. Gas leaves the separator at $\sim 207^{\circ}\text{F}$ and at 600 psi takes a pressure drop across the back pressure valve, and travels through more than one hundred feet of pipe before reaching the flare. The gas rapidly loses its pressure and its temperature. On a warm day, the pressure and temperature at the positive displacement meter was 10-20 psig and 115°F .

Much of the steam and a substantial quantity of the heavy aromatic hydrocarbons would condense out of the gas phase. This hypothesis was tested by blowing a small amount of liquid from the liquid knockout in front of the positive displacement meter. This liquid, while primarily water, contained

a noticeable amount of oil, leaving one's hand oily enough to cause the water to bead up. For this reason our flare line gas "oil-to-brine" ratio is only a lower limit. Substantial undocumented quantities of oil condensed from the gas phase before reaching the cold trap assembly and were blown-out of the liquid knockout onto the ground. We believe that the occasional liquids surmised to be burning in the flare come from undocumented, but not surprising, slugging of very small quantities of oil that had previously moved from the separator and condensed in the pipes and/or liquid knockout.

This slugging of oil in the surface equipment which periodically has recorded pressure fluctuations from the separator through the positive displacement meter adequately explains the occasional changes in the appearance of the flare. It was noted in the LBL report that, had a gas sample been caught as the flare turned orange and smoky, that substantial increases in the ethane, propane, butanes, and heavy aromatic hydrocarbon content would be observed. None of the 18 gas analyses performed by the University of Southwestern Louisiana shows convincing evidence that ethane/methane, propane/methane, and butanes/methane had substantially changed as would occur at the onset of free gas production from the reservoir. The cyclical appearance of the orange flame and smoke occurred about six times during the two days IGT personnel were on location. With this frequency, some of the gas samples analyzed by USL should have showed evidence of substantial increases in the heavy hydrocarbons. Also, if one concludes that the quantity of liquid hydrocarbons that condense out is roughly half of the amount observed in the samples collected in the cold traps after the positive displacement meters, then this would mean that at least 750 grams of oil would accumulate in the surface facilities every day. Only a small portion of this oil would be needed to make the flare very orange and sooty, as has been observed.

In conclusion, the reservoir appears to be slightly undersaturated. Pressure decreases due to production seem to lower the bottomhole pressure to slightly below the bubble point pressure, although the surface manifestations (the propane and butanes to methane ratios) are slight. This conclusion is reached based on the small changes in concentration of the flare line gas. If these compositional changes are due to surface phenomena--such as changing the calibration of the gas chromatograph, changing the gas sampling procedures, or increasing the separator static pressure -- then the reservoir will be undersaturated even at the flowing bottomhole pressure.

III. Were the Produced Liquid Hydrocarbons in Solution in the Brine at Reservoir Conditions?

The quantity of produced liquid hydrocarbons is very small. IGT found ~5 mg oil/liter brine after the separator (Table 4). An additional 1 mg oil/liter brine equivalent was trapped in the flare line cold traps operated by Dr. Dean Keeley of the University of Southwestern Louisiana. As was mentioned in the previous section, this second quantity is a lower limit. An indeterminate amount of oil condensed in the surface equipment before the gas passed through the cold traps. Also, liquids caught in the first ice water bath cold trap were discarded. Taking all of these factors into account, it is reasonable to assume that we collected some but not all of the liquid hydrocarbons that left the separator in the flare line gas. If the amount we collected was in error by 100%, this still would not significantly change the total quantity of liquid hydrocarbons produced per barrel brine (from 6 mg/l to 7 mg/l). In any case, this total quantity of oil could easily be dissolved in the brine at original reservoir conditions of pressure and temperature. Dr. Price, of USGS, Denver has also concluded that this oil was in solution in the brine at reservoir conditions.

The solubility of oils in brine is a strong function of the types of hydrocarbon - organic acids and aromatics are much more soluble than similar aliphatic hydrocarbons. For this reason, if oils are suspected of being in solution in the brine, these oils should be predominately organic acids and aromatic hydrocarbons such as benzenes and naphthalenes. Aliphatic hydrocarbons, on the other hand, are very insoluble in brine and are rarely found in solution. Oils collected from the gas and brine reveal predominately aromatic hydrocarbons. The large quantity of heavy aliphatics in the second water extraction is probably due to stopcock grease contamination. After running out of silicon grease in the field, we used grease provided by the University of Southwestern Louisiana personnel. We have no idea of the composition of this grease. Organic acids, while not looked for by IGT personnel, were observed by LBL but were not quantified in the report. The produced oil has all the characteristics associated with solubility in brines.

Although there is a lack of laboratory data on the solubility of oils in brine at these elevated pressures and temperatures, IGT uses a rule of thumb based on existing data and from the opinions of those most familiar with this

type of work, such as Dr. Leigh Price. This guideline is that it is not surprising to see aromatic hydrocarbons in geopressured-geothermal brines of up to about a 10^{-4} or 10^{-5} volume fraction. Aromatic hydrocarbons in these quantities are soluble in brine at reservoir conditions. If we assume that the produced oil has a density of about 0.8 grams/cc, then the quantity measured by IGT corresponds to a little less than a 10^{-5} volume fraction. Therefore we conclude, from these data and our rule of thumb, that the produced oil was in solution in the brine in the reservoir. There is no evidence of free hydrocarbon accumulations entering the wellbore. This is not to say that free oil hydrocarbon deposits may not exist elsewhere in the reservoir.

Conclusions

Our conclusions concerning the three questions presented in the introduction to this report are as follows:

- The amount of gas lost in disposal brine is about 3.8 SCF/STB, at separator conditions of 660 psig and 207°F. This is similar to values observed on other tests. This corresponds to a loss of about 3600 Btu of marketable gas per stock tank barrel of brine.
- The evidence suggests that the brine is close to being saturated at original reservoir conditions. The flowing bottomhole pressure has apparently been reduced to below the bubble point pressure during the long drawdown (the flowing bottomhole pressure is now below 10,200 psi, a decrease of more than one thousand psi). The effect of the dissolved oil and of possible free oil accumulations on the reservoir have not been defined for these saturation tests, nor have they been defined in relation to the capacity of brine to dissolve methane.
- The produced oil is dissolved in the brine at reservoir conditions. Both the type of oil (almost exclusively aromatic hydrocarbons) and the quantity of oil (less than 10^{-5} volume fraction) suggest that the oil was in solution. This is more than in any other well tested by IGT with the possible exception of the Lear G. Koelemay Well, which produced marketable quantities of oil, and the Martin-Crown Zellerbach Well No. 2, which produced as much as 10^{-4} volume fraction of oil. On the Martin-Crown Zellerbach well we are not certain that all the oil was in solution at reservoir conditions. This is also not to suggest that free oil deposits do not exist elsewhere in the Leroy Sweezy No. 1 producing reservoir, far from the well.

Recommendations

This section of the report contains recommendations to improve physical measurements made on the produced fluids and to check the validity of the saturation conclusion. The following points outline specific suggestions to improve our understanding of the quantity and composition of effluents produced from this well:

- Analyze the brine for calcium content. This analysis is important to detect changes due to scaling, to detect an influx of brine from accompanying shales, and to help follow changes in brine chemistry. This analysis is conspicuously absent in the otherwise extensive chemical results. We did note that calcium has been added for the latest analytical report to DOE.
- Measure the gas content in the brine after the separator. With the present equipment, this is best done by obtaining a sample from the bottom of the separator. Also analyze for the total carbon dioxide content as described by Hayden and Randolph (1981). Report hydrocarbon gases, gaseous carbon dioxide, and the carbon dioxide liberated using an acid liberation-nitrogen purge technique.
- Move tap for flareline cold traps from after the positive displacement meter to a port on top of the separator. Extreme care should be taken to make the system pressure proof. Ice or hydrate problems will definitely plug the collection vessels and cause pressure buildup unless proper precautions are taken.
- Place a fibrous material (either glass wool or steel wool) in the cold traps to trap droplets. All fractions, including that from the first ice water trap, should be combined. Each trap should have multiple washes with an appropriate solvent. This solvent - such a methylene chloride - should be combined with all the other liquids to ensure that all the trapped hydrocarbons were quantitatively removed. This will help in preserving trace amounts of light hydrocarbons for analysis.
- When hydrocarbons are trapped from the flare line gas, also trap and extract hydrocarbons from the brine. The liquid/liquid extraction in an ice bath performed by IGT was time consuming but appears to give good results. Apparently the amount of these heavy hydrocarbons that leave the separator in the gas phase are much less than the quantity that leaves the separator either dissolved or emulsified in the brine.
- Check the gas chromatograph with an independent standard having a composition closely resembling the gas to be analyzed.
- There is small differences in the ethane concentration reported by the University of Southwestern Louisiana and by IGT and LBL. There also appears to be a little more scatter in the gas composition than what we are used to seeing, particularly in the propane values. Try to reduce scatter by preheating sample cylinders and by analyzing the samples immediately.
- Attempt to modify the surface hardware to reduce surging in the flare line. Pressure at the positive displacement meter have been observed to fluctuate several psi in a period of minutes. This is a source of measurement error. In terms of the orifice meter run, it is very difficult to read an average pressure from a circular chart that has fluctuations.

- Collect solids from the separator and from the filters to get a particle size distribution. Use a 0.45 μm or 0.10 μm filter to determine what quantities of particulates are passing through the filter.

We also have several suggestions that can be made to verify the conclusions reached in this report and to increase our understanding of the produced effluents. These involve substantial changes from current plans and may involve substantial investments of time or money, and are for these reasons segregated from the suggestions provided above.

To test the hypothesis that the change in composition of the produced gas is due to the liberation of gas in the reservoir, the following test plan is proposed:

- Decrease the brine flow rate such that the flowing bottomhole pressure is only about 500 psi below the original bottomhole pressure.
- Keep this lower flow rate without changing any other surface conditions, especially the separator pressure.
- As brine that has not seen a large pressure drop is produced, propane and butanes to methane ratios should increase to their former levels.
- After the above conditions have existed for several weeks, open the choke to achieve a drawdown similar to that which exists now. Collect and analyze gas samples after 1- $\frac{1}{2}$, 2- $\frac{1}{2}$, and 5 well volumes have been produced, looking for a bubble of free gas.
- Continue the drawdown as is now being done and monitor the gas composition. The composition should return to where it is now.

To perform various experiments to reduce the back pressure build up on the disposal well, IGT suggests the following procedure:

- Install a 5 micron nominal size filter in line after the separator. IGT has observed, at flow rates of ~5000 bbls/day with a separator length of 10 feet and a diameter of ~39 inches, that most of the solid particles that are greater than 32 microns settle out in the separator. Of the particles caught by the filter elements, between 40 to 60 weight percent has generally been in the 4-16 micron range. A large portion of these very small particles will not be trapped by a 50 or 25 micron filter unit. IGT had considerable success with a unit consisting of 8 separate 5 micron filter elements with automatic back flushing capability. This unit may be available for installation, as was the Nowata 25 micron system that is now being used on this well but had previously been used on Wells of Opportunity tests.
- Lower the separator pressure to a value close to that required to push the brine down the disposal well. This may help prevent gas slugs exiting

the separator in the brine leg and being forced down the disposal well on the unlikely but possible assumption that this is a problem. This will also cause more carbon dioxide to exolve from the brine, and may cause small calcium carbonate precipitations to occur if conditions are near or at supersaturation of calcium and carbonate. If this scaling does occur, it would probably be trapped by the surface pipe or the 5 micron filters. In any case, this would decrease the concentration of carbon dioxide injected into the disposal formation. This idea is speculative but the action is easily performed, so IGT feels it will be worthwhile.

- Periodically bypass the separator and check for sand loading. If significant quantities of sand are seen, the separator should be blown clean.

APPENDIX. RELATED DATA ON PARC PERDUE REPORT

C-29/30

Table I. THE COMPOSITION (MOLE PERCENT) OF THE FLARE LINE GAS PROVIDED BY DOW CHEMICAL AND ITS SUBCONTRACTORS

<u>Date</u>	<u>Nitrogen</u>	<u>Carbon Dioxide</u>	<u>Methane</u>	<u>Ethane</u>	<u>Propane</u>	<u>iso-Butane</u>	<u>n-Butane</u>	<u>iso-Pentane</u>
5-12-82	0.43	2.79	93.82	2.46	0.36	0.10	0.04	0.01
5-13-82	0.42	2.70	93.81	2.46	0.36	0.10	0.03	0.01
5-18-82	0.48	2.77	93.77	2.46	0.37	0.10	0.04	0.01
5-20-82	0.50	2.65	93.87	2.48	0.37	0.08	0.03	0.01
6-8-82	0.39	2.54	93.94	2.48	0.38	0.10	0.06	0.02
6-11-82	0.35	2.37	94.29	2.48	0.37	0.09	0.03	0.01
6-14-82	0.36	2.54	93.60	2.53	0.83	0.10	0.03	0.01
6-17-82	0.36	2.42	94.30	2.48	0.31	0.09	0.03	0.01
6-21-82	0.35	2.44	94.27	2.49	0.32	0.09	0.03	0.01
6-25-82	0.51	2.41	94.12	2.47	0.37	0.09	0.03	0.01
7-7-82	0.42	2.49	94.18	2.45	0.31	0.10	0.03	0.01
7-16-82	0.37	2.56	94.17	2.45	0.31	0.09	0.03	0.01
7-28-82	0.36	2.48	94.24	2.46	0.31	0.09	0.03	0.01
8-5-82	0.42	2.45	94.18	2.45	0.36	0.09	0.03	0.00
8-16-82	0.39	2.49	94.22	2.47	0.31	0.09	0.03	0.00
8-23-82	0.37	2.47	94.25	2.47	0.31	0.09	0.03	0.01
9-1-82	0.37	2.38	94.33	2.48	0.31	0.09	0.03	0.01
9-20-82	0.40	2.40	94.28	2.47	0.31	0.09	0.03	0.01

C-34/32

Analog Display of a Chromatogram of
the Produced Oils in the Methylene
Chloride Solvent Analyzed by Capillary
Gas Chromatography/Mass Spectrometry

C-33/34

RIC

10/12/82 15:28:00

DATA: BRINEKO #1

SCANS 1 TO 4193

CALI: 1012CAL #3

SAMPLE: 82-607, MECL2 EXTRC OF LG/GAS SEP

CONDS.: 5UL, SPLT 40, 1KV, 0.2MA, GC ATTACH

RANGE: G 1,4193 LABEL: N 0, 4.0 QUAN: A 0, 1.0 J 0 BASE: U 20, 3

55296.

Detailed Report of the Quantity and
Composition of Liquids Extracted From
the Flare Line Using Cold Traps, in a
Methylene Chloride Solvent, as Determined
by Capillary Gas Chromatography/Mass
Spectrometry.

PROJECT: 61025 00

LAB NO. 82-687

SAMPLE: EXTRACT OF GAS LIQUID KNOCKOUT PARC PERDUE WELL

GC DETERMINATION OF QUANTITY AND COMPOSITION OF SOLUTE IN EXTRACT

WEIGHT METHYLENE CHLORIDE RECEIVED: 12.4 GRAMS

TOTAL ORGANICS IN EXTRACT: 438 MILLIGRAMS

COMPOSITION IN WEIGHT PER CENT OF TOTAL ORGANICS FOUND
ONLY MAJOR COMPONENTS IDENTIFIED

I. ALIPHATIC HYDROCARBONS

CARBON NO.	N-ALKANE	OTHER (ISO-,CYCLO,ECT,...)
5	0.1	0.1
6	0.38	0.63
7	0.62	4.12
8	0.52	0.76
9	0.1	0.47
10	0.03	INCLD. IN UNID.
11	0.03	"
12	0.04	"
13	0.04	"
14	0.04	"
15	0.04	"
16	0.04	"
17	0.03	"
18	<0.02	"
19	<0.02	"
20	<0.02	"
21	"	"
22	"	"
23	"	"
24	"	"
25	"	"
26	"	"
27	"	"
28	"	"
29	"	"
30	"	"
31	"	"
32	"	"
SUM	2.0	6.1

II. AROMATIC HYDROCARBONS

TYPE		BASE COMPOUND	METHYL	C2	C3+
ONE RING	BENZENE	20.7	22.7	23.5	11.81
	INDAN	0.10	-	0.14	0.07
TWO RING	NAPHTHALENE	2.74	2.78	1.78	0.51
	BIPHENYL	0.44	0.22		

III. NITROGEN CONTAINING COMPOUNDS

NO COMPONENT GREATER THAN 0.1%

IV. OXYGEN CONTAINING COMPOUNDS

	BASE COMPOUND	METHYL	C2	C3+
DIBENZOFURANS	0.06	0.02		

V. SULFUR CONTAINING COMPOUNDS

NO COMPONENT GREATER THAN 0.1%

NON-POLAR COMPOUNDS

BOILING BELOW NAPHTHALENE

BOILING BETWEEN NAPHTHALENE AND PHENANTHRENE ...

BOILING ABOVE PHENANTHRENE

POLAR COMPOUNDS

TOTAL UNIDENTIFIED 4.3%

Detailed Reports of the Quantity and
Composition of the Produced Oil in
the Methylene Chloride Extract From
Post Separator Brine as Determined
Using Capillary Gas Chromatography/
Mass Spectrometry.

C-41/42

1GT CHROMATOGRAPHY LABORATORY ANALYTICAL REPORT 20 OCT

PROJECT: 61025 00

LAB NO. 82-608

SAMPLE: EXTRACT OF BRINE

GC DETERMINATION OF QUANTITY AND COMPOSITION OF SOLUTE IN EXTRACT

WEIGHT METHYLENE CHLORIDE RECIEVED: 17.9 GRAMS

TOTAL ORGANICS IN EXTRACT: 8.6 MILLIGRAMS

COMPOSITION IN WEIGHT PER CENT OF TOTAL ORGANICS FOUND
ONLY MAJOR COMPONENTS IDENTIFIED

I. ALIPHATIC HYDROCARBONS

CARBON NO. N-ALKANE OTHER (ISO-,CYCLO,ECT...)

NO COMPONENT GREATER THAN 0.04%

II. AROMATIC HYDROCARBONS

TYPE		BASE COMPOUND	METHYL	C2	C3+
ONE RING	BENZENE	41.2	21.0	11.4	3.1
	INDAN	-	-	-	-
TWO RING	NAPHTHALENE	6.6	3.7	1.5	-
	DIPHENYL	0.50	-	-	-

III. NITROGEN CONTAINING COMPOUNDS

NO COMPONENT GREATER THAN 0.2%

IV. OXYGEN CONTAINING COMPOUNDS

	BASE COMPOUND	METHYL	C2	C3+
PHENOL	1.9	2.9	0.5	-

V. SULFUR CONTAINING COMPOUNDS

NO COMPONENT GREATER THAN 0.1%

NON-POLAR COMPOUNDS

BOILING BELOW NAPHTHALENE

BOILING BETWEEN NAPHTHALENE AND PHENANTHRENE ...

BOILING ABOVE PHENANTHRENE

POLAR COMPOUNDS

TOTAL UNIDENTIFIED 5.7%

1GT CHROMATOGRAPHY LABORATORY ANALYTICAL REPORT 18 OCT

PROJECT: 61025 00 LAB NO. 82-603
 SAMPLE: EXTRACT, SEPT.23 10-1460 HRS.

GC DETERMINATION OF QUANTITY AND COMPOSITION OF SOLUTE IN EXTRACT

WEIGHT METHYLENE CHLORIDE RECEIVED: 19.8 GRAMS

TOTAL ORGANICS IN EXTRACT: 11 MILLIGRAMS

COMPOSITION IN WEIGHT PER CENT OF TOTAL ORGANICS FOUND
 ONLY MAJOR COMPONENTS IDENTIFIED

1. ALIPHATIC HYDROCARBONS		
CARBON NO.	N-ALKANE	OTHER (ISO-,CYCLO,ECT...)
5	<0.05	<0.05
6	<0.05	<0.05
7	<0.05	<0.05
8	<0.05	<0.05
9	<0.05	<0.05
10	<0.05	<0.05
11	<0.05	<0.05
12	<0.05	<0.05
13	0.02	<0.05
14	0.02	<0.05
15	0.02	<0.05
16	0.04	<0.05
17	0.09	<0.05
18	0.09	0.27
19	0.23	0.32
20	0.28	0.32
21	0.48	0.45
22	0.80	0.52
23	1.1	0.54
24	1.6	0.70
25	1.6	0.84
26	1.7	0.56
27	1.5	0.45
28	1.4	0.34
29	1.0	0.20
30	0.70	0.10
31	0.60	0.10
32	0.40	<0.10
SUM	13.7	5.7

II. AROMATIC HYDROCARBONS

TYPE		BASE COMPOUND	METHYL	C2	C3+
ONE	BENZENE	35.0	17.7	9.6	2.9
RING	INDAN	-	-	-	-
TWO	NAPHTHALENE	5.1	2.7	1.2	(0.10)
RING	BIPHENYL	0.37	-	-	-

III. NITROGEN CONTAINING COMPOUNDS

NO COMPONENT GREATER THAN 0.1%

IV. OXYGEN CONTAINING COMPOUNDS

	BASE COMPOUND	METHYL	C2	C3+
PHENOL	1.6	2.0	0.3	-

V. SULFUR CONTAINING COMPOUNDS

NO COMPONENT GREATER THAN 0.1%

NON-POLAR COMPOUNDS	
BOILING BELOW NAPHTHALENE	
BOILING BETWEEN NAPHTHALENE AND PHENANTHRENE ...	
BOILING ABOVE PHENANTHRENE	
POLAR COMPOUNDS	
TOTAL UNIDENTIFIED	2.1%

Analytical Report and the Analog Display
of the Chromatograms of the Oil Trapped
by the Sep Pac Cartridges Analyzed by
Capillary Gas Chromatography (the peaks
were not identified).

C-47/48

I	GGGGG	TTTTTTT
I	G	T
I	G GGG	T
I	G G	T
I	GGGG	T

INSTITUTE OF GAS TECHNOLOGY
CHROMATOGRAPHY LABORATORY
ANALYTICAL REPORT

PROJECT NO.: 61025-00 DATE: 10-20-82 REQUESTED BY: C. HAYDEN
LAB. NO.(S): 82-609
SAMPLE DESCRIPTION: SEP-PAC CARTRIDGES

CAPILLARY GC/FID DETERMINATION OF COMPONENTS
TRAPPED ON C-18 SEP-PAC CARTRIDGES

ADSORBED ORGANICS WERE ELUTED FROM THE CARTRIDGES WITH 3 2.5 ML ALIQUOTES OF METHYLENE CHLORIDE IN EACH CASE. THE ALIQUOTES WERE COMBINED, CONCENTRATED BY NITROGEN BLOWDOWN, AND ANALYZED.

FUNDING ALLOTTED WAS NOT SUFFICIENT TO COMPLETE DATA ANALYSIS. A REPORT OF THE COMPOSITION OF THE MATERIAL ELUTED COULD BE PROVIDED IF INTEREST NECESSITATES AND ADDITIONAL FUNDING BECOMES AVAILABLE.

FOR REFERENCE, A COPY OF THE CHROMATOGRAM OBTAINED FROM EACH SAMPLE IS ATTACHED.

THE TOTAL WEIGHT OF MATERIAL ELUTED FROM EACH SAMPLE WAS AS FOLLOWS:

82-609	SEPT. 23, 1050HR	1.7 MG
82-610	SEPT. 23	1.5 MG
82-611	SEPT. 23, 1200HR	1.7 MG

ANALYSTS: K.P., B.H.S.

Chromatogram of a methylene chloride
extract for reference comparison to
attached Sep-Pac sample chromatograms

Total Organics
recovered = 11 mg

NAPHTHALENE

m-130

m-132

GC Column bleed

82-603 Methylene Chloride Extract
Sep-Pac 23 10-1400 hrs
1 µl + 1 µl solvent flush

C-53

APPENDIX D.

Tables of Methane Solubility in Brine
Based on System Science & Software,
Blount, and Haas Equations

SOLUBILITY OF METHANE IN BRINE
FILE NAME : SOL22

PRESSURE	SALINITY	TEMPERATURE	DENSITY OF BRINE	-----SOLUBILITY, SCF/STB-----		
				SYST. SCIENCE & SOFTWARE	(MAR. '81) BLOUNT EQ.	HAAS' EQ.
PSI	WT %	DEG F	LB/FT3			
1000	2.50	200	63.45	5.89	8.02	6.03
1500	2.50	200	63.45	8.30	10.28	8.46
2000	2.50	200	63.45	10.42	12.24	10.62
2500	2.50	200	63.45	12.28	14.00	12.56
3000	2.50	200	63.45	13.93	15.60	14.32
3500	2.50	200	63.45	15.42	17.08	15.94
4000	2.50	200	63.45	16.79	18.46	17.45
4500	2.50	200	63.45	18.05	19.75	18.85
5000	2.50	200	63.45	19.24	20.97	20.16
5500	2.50	200	63.45	20.35	22.13	21.39
6000	2.50	200	63.45	21.39	23.23	22.56
6500	2.50	200	63.45	22.38	24.28	23.66
7000	2.50	200	63.45	23.32	25.28	24.71
7500	2.50	200	63.45	24.21	26.23	25.71
8000	2.50	200	63.45	25.06	27.15	26.67
8500	2.50	200	63.45	25.87	28.03	27.59
9000	2.50	200	63.45	26.65	28.88	28.47
9500	2.50	200	63.45	27.40	29.69	29.32
10000	2.50	200	63.45	28.11	30.47	30.13
10500	2.50	200	63.45	28.80	31.23	30.92
11000	2.50	200	63.45	29.47	31.96	31.68
11500	2.50	200	63.45	30.11	32.66	32.41
12000	2.50	200	63.45	30.72	33.34	33.13
12500	2.50	200	63.45	31.32	33.99	33.81
13000	2.50	200	63.45	31.90	34.63	34.48
13500	2.50	200	63.45	32.46	35.24	35.13
14000	2.50	200	63.45	33.00	35.83	35.77
14500	2.50	200	63.45	33.52	36.41	36.38
15000	2.50	200	63.45	34.03	36.96	36.98

SOLUBILITY OF METHANE IN BRINE
FILE NAME : SOL23

PRESSURE	SALINITY	TEMPERATURE	DENSITY OF BRINE LB/FT3	-----SOLUBILITY, SCF/STB-----		
				SYST. SCIENCE & SOFTWARE	(MAR.'81) BLOUNT EQ.	HAAS' EQ.
PSI	WT %	DEG F				
1000	2.50	210	63.45	5.85	8.28	6.08
1500	2.50	210	63.45	8.28	10.61	8.56
2000	2.50	210	63.45	10.43	12.64	10.76
2500	2.50	210	63.45	12.34	14.45	12.74
3000	2.50	210	63.45	14.04	16.10	14.55
3500	2.50	210	63.45	15.58	17.62	16.21
4000	2.50	210	63.45	16.98	19.05	17.76
4500	2.50	210	63.45	18.29	20.38	19.19
5000	2.50	210	63.45	19.50	21.64	20.54
5500	2.50	210	63.45	20.65	22.84	21.81
6000	2.50	210	63.45	21.73	23.97	23.02
6500	2.50	210	63.45	22.75	25.05	24.16
7000	2.50	210	63.45	23.72	26.08	25.24
7500	2.50	210	63.45	24.65	27.07	26.27
8000	2.50	210	63.45	25.53	28.02	27.26
8500	2.50	210	63.45	26.38	28.92	28.21
9000	2.50	210	63.45	27.19	29.80	29.12
9500	2.50	210	63.45	27.98	30.64	30.00
10000	2.50	210	63.45	28.73	31.44	30.84
10500	2.50	210	63.45	29.45	32.22	31.65
11000	2.50	210	63.45	30.15	32.98	32.44
11500	2.50	210	63.45	30.82	33.70	33.20
12000	2.50	210	63.45	31.48	34.40	33.94
12500	2.50	210	63.45	32.11	35.08	34.65
13000	2.50	210	63.45	32.72	35.73	35.34
13500	2.50	210	63.45	33.31	36.36	36.02
14000	2.50	210	63.45	33.89	36.97	36.67
14500	2.50	210	63.45	34.44	37.57	37.31
15000	2.50	210	63.45	34.99	38.14	37.93

SOLUBILITY OF METHANE IN BRINE
FILE NAME : SOL24

PRESSURE PSI	SALINITY WT %	TEMPERATURE DEG F	DENSITY OF BRINE LB/FT3	-----SOLUBILITY, SCF/STR-----		
				SYST. SCIENCE & SOFTWARE	(MAR. '81) BLOUNT EQ.	HAAS' EQ.
1000	2.50	220	63.45	5.84	8.56	6.15
1500	2.50	220	63.45	8.30	10.97	8.68
2000	2.50	220	63.45	10.50	13.06	10.93
2500	2.50	220	63.45	12.46	14.93	12.97
3000	2.50	220	63.45	14.23	16.64	14.83
3500	2.50	220	63.45	15.82	18.21	16.54
4000	2.50	220	63.45	17.27	19.68	18.13
4500	2.50	220	63.45	18.61	21.07	19.61
5000	2.50	220	63.45	19.87	22.37	21.01
5500	2.50	220	63.45	21.05	23.60	22.32
6000	2.50	220	63.45	22.17	24.77	23.56
6500	2.50	220	63.45	23.23	25.89	24.74
7000	2.50	220	63.45	24.24	26.96	25.86
7500	2.50	220	63.45	25.21	27.98	26.93
8000	2.50	220	63.45	26.14	28.95	27.95
8500	2.50	220	63.45	27.02	29.89	28.94
9000	2.50	220	63.45	27.88	30.80	29.88
9500	2.50	220	63.45	28.70	31.66	30.79
10000	2.50	220	63.45	29.49	32.50	31.66
10500	2.50	220	63.45	30.25	33.30	32.50
11000	2.50	220	63.45	30.99	34.08	33.32
11500	2.50	220	63.45	31.70	34.83	34.11
12000	2.50	220	63.45	32.40	35.55	34.87
12500	2.50	220	63.45	33.07	36.25	35.61
13000	2.50	220	63.45	33.72	36.93	36.33
13500	2.50	220	63.45	34.35	37.58	37.03
14000	2.50	220	63.45	34.97	38.21	37.71
14500	2.50	220	63.45	35.57	38.83	38.37
15000	2.50	220	63.45	36.15	39.42	39.02

SOLUBILITY OF METHANE IN BRINE
FILE NAME : SOL25

PRESSURE PSI	SALINITY WT %	TEMPERATURE DEG F	DENSITY OF BRINE LB/FT3	-----SOLUBILITY, SCF/STB-----		
				SYST. SCIENCE & SOFTWARE	(MAR.'81) BLOUNT EQ.	HAAS' EQ.
1000	2.50	230	63.45	5.86	8.85	6.25
1500	2.50	230	63.45	8.37	11.35	8.84
2000	2.50	230	63.45	10.62	13.51	11.15
2500	2.50	230	63.45	12.65	15.45	13.25
3000	2.50	230	63.45	14.48	17.22	15.16
3500	2.50	230	63.45	16.13	18.85	16.93
4000	2.50	230	63.45	17.63	20.37	18.57
4500	2.50	230	63.45	19.02	21.80	20.10
5000	2.50	230	63.45	20.32	23.15	21.55
5500	2.50	230	63.45	21.55	24.43	22.90
6000	2.50	230	63.45	22.72	25.64	24.19
6500	2.50	230	63.45	23.82	26.80	25.41
7000	2.50	230	63.45	24.88	27.90	26.57
7500	2.50	230	63.45	25.89	28.96	27.68
8000	2.50	230	63.45	26.86	29.97	28.75
8500	2.50	230	63.45	27.80	30.94	29.77
9000	2.50	230	63.45	28.69	31.87	30.74
9500	2.50	230	63.45	29.56	32.77	31.69
10000	2.50	230	63.45	30.40	33.64	32.59
10500	2.50	230	63.45	31.21	34.47	33.47
11000	2.50	230	63.45	31.99	35.28	34.32
11500	2.50	230	63.45	32.75	36.05	35.14
12000	2.50	230	63.45	33.49	36.80	35.93
12500	2.50	230	63.45	34.20	37.53	36.70
13000	2.50	230	63.45	34.90	38.23	37.45
13500	2.50	230	63.45	35.58	38.90	38.18
14000	2.50	230	63.45	36.24	39.56	38.89
14500	2.50	230	63.45	36.88	40.19	39.58
15000	2.50	230	63.45	37.51	40.80	40.25

SOLUBILITY OF METHANE IN BRINE
FILE NAME : SOL26

PRESSURE	SALINITY	TEMPERATURE	DENSITY OF BRINE LB/FT3	-----SOLUBILITY, SCF/STB-----		
				SYST. SCIENCE & SOFTWARE	(MAR. '81) BLOUNT EQ.	HAAS' EQ.
PSI	WT %	DEG F				
1000	2.50	240	63.45	5.91	9.17	6.36
1500	2.50	240	63.45	8.47	11.76	9.02
2000	2.50	240	63.45	10.79	14.00	11.41
2500	2.50	240	63.45	12.90	16.01	13.57
3000	2.50	240	63.45	14.80	17.84	15.55
3500	2.50	240	63.45	16.52	19.53	17.38
4000	2.50	240	63.45	18.08	21.11	19.08
4500	2.50	240	63.45	19.52	22.59	20.67
5000	2.50	240	63.45	20.87	23.99	22.16
5500	2.50	240	63.45	22.15	25.32	23.57
6000	2.50	240	63.45	23.37	26.57	24.90
6500	2.50	240	63.45	24.52	27.77	26.17
7000	2.50	240	63.45	25.63	28.92	27.38
7500	2.50	240	63.45	26.70	30.01	28.54
8000	2.50	240	63.45	27.72	31.06	29.64
8500	2.50	240	63.45	28.70	32.07	30.70
9000	2.50	240	63.45	29.65	33.04	31.72
9500	2.50	240	63.45	30.57	33.97	32.70
10000	2.50	240	63.45	31.45	34.87	33.64
10500	2.50	240	63.45	32.31	35.74	34.56
11000	2.50	240	63.45	33.15	36.57	35.44
11500	2.50	240	63.45	33.96	37.37	36.29
12000	2.50	240	63.45	34.75	38.15	37.12
12500	2.50	240	63.45	35.51	38.90	37.93
13000	2.50	240	63.45	36.26	39.63	38.71
13500	2.50	240	63.45	36.99	40.33	39.46
14000	2.50	240	63.45	37.70	41.01	40.20
14500	2.50	240	63.45	38.40	41.67	40.92
15000	2.50	240	63.45	39.07	42.30	41.62

SOLUBILITY OF METHANE IN BRINE
FILE NAME : SOL27

PRESSURE PSI	SALINITY WT %	TEMPERATURE DEG F	DENSITY OF BRINE LB/FT3	-----SOLUBILITY, SCF/STB-----		
				SYST. SCIENCE & SOFTWARE	(MAR. '81) BLOUNT EQ.	HAAS' EQ.
1000	2.50	250	63.45	5.99	9.51	6.49
1500	2.50	250	63.45	8.62	12.19	9.24
2000	2.50	250	63.45	11.02	14.52	11.70
2500	2.50	250	63.45	13.20	16.61	13.94
3000	2.50	250	63.45	15.19	18.51	15.99
3500	2.50	250	63.45	16.98	20.27	17.88
4000	2.50	250	63.45	18.61	21.91	19.65
4500	2.50	250	63.45	20.10	23.45	21.30
5000	2.50	250	63.45	21.51	24.90	22.85
5500	2.50	250	63.45	22.85	26.27	24.32
6000	2.50	250	63.45	24.12	27.58	25.71
6500	2.50	250	63.45	25.34	28.83	27.03
7000	2.50	250	63.45	26.50	30.02	28.29
7500	2.50	250	63.45	27.62	31.15	29.49
8000	2.50	250	63.45	28.70	32.25	30.64
8500	2.50	250	63.45	29.73	33.29	31.74
9000	2.50	250	63.45	30.74	34.30	32.81
9500	2.50	250	63.45	31.71	35.27	33.83
10000	2.50	250	63.45	32.66	36.20	34.81
10500	2.50	250	63.45	33.57	37.10	35.77
11000	2.50	250	63.45	34.46	37.97	36.69
11500	2.50	250	63.45	35.33	38.80	37.58
12000	2.50	250	63.45	36.17	39.61	38.44
12500	2.50	250	63.45	37.00	40.39	39.28
13000	2.50	250	63.45	37.80	41.15	40.10
13500	2.50	250	63.45	38.59	41.88	40.89
14000	2.50	250	63.45	39.35	42.58	41.66
14500	2.50	250	63.45	40.10	43.26	42.41
15000	2.50	250	63.45	40.84	43.93	43.14

SOLUBILITY OF METHANE IN BRINE
FILE NAME : SOL28

PRESSURE	SALINITY	TEMPERATURE	DENSITY OF BRINE	-----SOLUBILITY, SCF/STB-----		
				SYST. SCIENCE & SOFTWARE	(MAR. '81) BLOUNT EQ.	HAAS' EQ.
PSI	WT %	DEG F	LB/FT3			
1000	2.50	260	63.45	6.10	9.87	6.64
1500	2.50	260	63.45	8.81	12.66	9.48
2000	2.50	260	63.45	11.30	15.08	12.03
2500	2.50	260	63.45	13.57	17.25	14.35
3000	2.50	260	63.45	15.65	19.23	16.48
3500	2.50	260	63.45	17.53	21.06	18.45
4000	2.50	260	63.45	19.22	22.76	20.29
4500	2.50	260	63.45	20.78	24.37	22.01
5000	2.50	260	63.45	22.25	25.88	23.62
5500	2.50	260	63.45	23.65	27.31	25.15
6000	2.50	260	63.45	24.98	28.67	26.60
6500	2.50	260	63.45	26.26	29.96	27.98
7000	2.50	260	63.45	27.48	31.20	29.29
7500	2.50	260	63.45	28.66	32.39	30.55
8000	2.50	260	63.45	29.80	33.52	31.75
8500	2.50	260	63.45	30.90	34.61	32.90
9000	2.50	260	63.45	31.97	35.66	34.01
9500	2.50	260	63.45	33.00	36.67	35.08
10000	2.50	260	63.45	34.01	37.64	36.11
10500	2.50	260	63.45	34.98	38.57	37.11
11000	2.50	260	63.45	35.94	39.47	38.07
11500	2.50	260	63.45	36.86	40.35	39.00
12000	2.50	260	63.45	37.77	41.19	39.91
12500	2.50	260	63.45	38.66	42.00	40.78
13000	2.50	260	63.45	39.52	42.78	41.63
13500	2.50	260	63.45	40.37	43.54	42.46
14000	2.50	260	63.45	41.20	44.28	43.27
14500	2.50	260	63.45	42.01	44.99	44.06
15000	2.50	260	63.45	42.80	45.68	44.82

SOLUBILITY OF METHANE IN BRINE
FILE NAME : SOL29

PRESSURE PSI	SALINITY WT %	TEMPERATURE DEG F	DENSITY OF BRINE LB/FT3	-----SOLUBILITY, SCF/STB-----		
				SYST. SCIENCE & SOFTWARE	(MAR. '81) BLOUNT EQ.	HAAS' EQ.
1000	2.50	270	63.45	6.24	10.26	6.81
1500	2.50	270	63.45	9.04	13.17	9.75
2000	2.50	270	63.45	11.63	15.69	12.40
2500	2.50	270	63.45	14.01	17.94	14.81
3000	2.50	270	63.45	16.18	20.01	17.03
3500	2.50	270	63.45	18.15	21.91	19.08
4000	2.50	270	63.45	19.92	23.69	21.00
4500	2.50	270	63.45	21.54	25.35	22.79
5000	2.50	270	63.45	23.08	26.93	24.48
5500	2.50	270	63.45	24.54	28.42	26.07
6000	2.50	270	63.45	25.94	29.84	27.59
6500	2.50	270	63.45	27.29	31.19	29.03
7000	2.50	270	63.45	28.58	32.48	30.40
7500	2.50	270	63.45	29.83	33.71	31.71
8000	2.50	270	63.45	31.03	34.90	32.97
8500	2.50	270	63.45	32.20	36.03	34.18
9000	2.50	270	63.45	33.33	37.12	35.34
9500	2.50	270	63.45	34.43	38.17	36.46
10000	2.50	270	63.45	35.51	39.19	37.54
10500	2.50	270	63.45	36.55	40.16	38.58
11000	2.50	270	63.45	37.57	41.10	39.59
11500	2.50	270	63.45	38.56	42.01	40.57
12000	2.50	270	63.45	39.54	42.89	41.51
12500	2.50	270	63.45	40.49	43.73	42.43
13000	2.50	270	63.45	41.42	44.55	43.33
13500	2.50	270	63.45	42.33	45.35	44.19
14000	2.50	270	63.45	43.23	46.11	45.04
14500	2.50	270	63.45	44.11	46.85	45.86
15000	2.50	270	63.45	44.97	47.57	46.67

SOLUBILITY OF METHANE IN BRINE
FILE NAME : SOL30

PRESSURE PSI	SALINITY WT %	TEMPERATURE DEG F	DENSITY OF BRINE LB/FT3	-----SOLUBILITY, SCF/STB-----		
				SYST. SCIENCE & SOFTWARE	(MAR. '81) BLOUNT EQ.	HAAS' EQ.
1000	2.50	280	63.45	6.41	10.68	6.99
1500	2.50	280	63.45	9.31	13.71	10.05
2000	2.50	280	63.45	12.01	16.34	12.81
2500	2.50	280	63.45	14.50	18.69	15.32
3000	2.50	280	63.45	16.78	20.84	17.64
3500	2.50	280	63.45	18.85	22.82	19.78
4000	2.50	280	63.45	20.70	24.68	21.78
4500	2.50	280	63.45	22.39	26.42	23.66
5000	2.50	280	63.45	24.00	28.06	25.42
5500	2.50	280	63.45	25.54	29.62	27.09
6000	2.50	280	63.45	27.01	31.10	28.68
6500	2.50	280	63.45	28.43	32.51	30.18
7000	2.50	280	63.45	29.79	33.85	31.62
7500	2.50	280	63.45	31.11	35.14	33.00
8000	2.50	280	63.45	32.39	36.38	34.31
8500	2.50	280	63.45	33.63	37.56	35.58
9000	2.50	280	63.45	34.83	38.70	36.80
9500	2.50	280	63.45	36.01	39.80	37.97
10000	2.50	280	63.45	37.15	40.86	39.10
10500	2.50	280	63.45	38.27	41.88	40.20
11000	2.50	280	63.45	39.36	42.86	41.26
11500	2.50	280	63.45	40.43	43.81	42.28
12000	2.50	280	63.45	41.47	44.72	43.28
12500	2.50	280	63.45	42.50	45.61	44.24
13000	2.50	280	63.45	43.50	46.46	45.18
13500	2.50	280	63.45	44.49	47.29	46.09
14000	2.50	280	63.45	45.45	48.09	46.98
14500	2.50	280	63.45	46.40	48.87	47.84
15000	2.50	280	63.45	47.34	49.62	48.69

SOLUBILITY OF METHANE IN BRINE
FILE NAME : SOL31

PRESSURE	SALINITY	TEMPERATURE	DENSITY OF BRINE	-----SOLUBILITY, SCF/STB-----		
				SYST. SCIENCE & SOFTWARE	(MAR.'81) BLOUNT EQ.	HAAS' EQ.
PSI	WT %	DEG F	LB/FT3			
1000	2.50	290	63.45	6.61	11.13	7.19
1500	2.50	290	63.45	9.62	14.29	10.38
2000	2.50	290	63.45	12.44	17.03	13.26
2500	2.50	290	63.45	15.06	19.49	15.88
3000	2.50	290	63.45	17.45	21.73	18.30
3500	2.50	290	63.45	19.62	23.81	20.55
4000	2.50	290	63.45	21.56	25.74	22.64
4500	2.50	290	63.45	23.33	27.56	24.60
5000	2.50	290	63.45	25.02	29.28	26.46
5500	2.50	290	63.45	26.64	30.91	28.21
6000	2.50	290	63.45	28.19	32.45	29.87
6500	2.50	290	63.45	29.68	33.93	31.45
7000	2.50	290	63.45	31.12	35.33	32.96
7500	2.50	290	63.45	32.52	36.68	34.40
8000	2.50	290	63.45	33.87	37.97	35.79
8500	2.50	290	63.45	35.19	39.21	37.12
9000	2.50	290	63.45	36.47	40.41	38.39
9500	2.50	290	63.45	37.72	41.56	39.63
10000	2.50	290	63.45	38.95	42.66	40.82
10500	2.50	290	63.45	40.14	43.73	41.97
11000	2.50	290	63.45	41.31	44.75	43.08
11500	2.50	290	63.45	42.45	45.75	44.16
12000	2.50	290	63.45	43.58	46.71	45.20
12500	2.50	290	63.45	44.68	47.63	46.22
13000	2.50	290	63.45	45.76	48.53	47.20
13500	2.50	290	63.45	46.82	49.39	48.16
14000	2.50	290	63.45	47.87	50.23	49.10
14500	2.50	290	63.45	48.90	51.04	50.01
15000	2.50	290	63.45	49.91	51.83	50.90

APPENDIX E.

Do We Know Whether The Pleasant Bayou #2
is Saturated With Methane?

IGT TECHNICAL REPORT

"Do We Know Whether the Pleasant
Bayou #2 is Saturated with Methane?"

Philip L. Randolph
Evelyn M. Rockar

Unconventional Natural Gas

Institute of Gas Technology
3424 South State Street
Chicago, Illinois 60616

May, 1981

INTRODUCTION

This report brings together from several DOE and GRI funded programs enough information for us to update our understanding of the degree of saturation of the Pleasant Bayou aquifer. We are able to update at this time for several reasons;

- Professor Blount has corrected a systematic error in his data interpretation procedure which causes his previously reported solubility values to be revised downwards and he has studied methane solubility in actual Pleasant Bayou brine.
- IGT has collected and analysed flare line gas and gas flashed from brine for samples collected at the Pleasant Bayou in early October 1980.
- IGT has developed a procedure for interpreting production data for the Wells of Opportunity that gives corrected values for GWR's.

Professor Blount's work has been sponsored by G.R.I. through a subcontract on IGT's "Gas Saturation in Formation Waters" program and by D.O.E. The gas analysis mentioned above was also carried out under the "Gas Saturation in Formation Waters" program. The procedure for interpreting production data was developed by IGT under a subcontract from Eaton Operating Company for production analysis on D.O.E. "Wells of Opportunity" program. Finally the compilation and interpretation of the data reported here were performed under GRI-IGT's "Gas Saturation in Formation Waters" and DOE-IGT's "Computer Simulation for Production of Geopressured-Geothermal Aquifers" contracts.

The most interesting result of this update is the convergence on the value 27-28 SCF/STB for both laboratory and field data analyses for the gas to water ratio (GWR). However, a conclusion as to whether the aquifer brine is saturated at this gas content still requires:

- Determining whether the brine leaving the separator contains gas bubbles and, if so, quantifying their gas content in relation to brine volume.
- Laboratory recombination studies using separator gas and brine samples taken at the separator pressure.
- Improved understanding of the extent to which observed CO₂ is actually in carbonate form before the brine is produced from the aquifer.

The following sections describe how the value of 27-28 SCF/STB was determined from production data, field flashing and laboratory studies. A final section discusses this work in relation to relevant publications on gas solubility in brine.

FIELD DATA INTERPRETATION

The subheadings which follow describe the calculations performed to verify the use of proper meter dimensions and describe details of each of the six steps in the procedure now used by IGT for determining gas to water ratio on "Wells of Opportunity." These calculations were applied to production data obtained by Weatherly Engineering, Inc. for October 8, 1980 at about 2000 hours. This is the time of separator fluid sampling by IGT.

Meter Run Dimensions

The orifice meter is assumed to have an inside diameter of 1.939 inches with a 0.75 inch orifice. This was tested by calculating gas to water ratio with the assumption that:

- Dry Gas Gravity = 0.600 relative to air.
- Supercompressibility = 1.000.

For a pressure base of 14.73 psia and a temperature base of 60°F, the orifice temperature (238°F) static pressure (790 psig) and differential pressure (12 inches water) for 2005 hours on October 8, 1980 give a calculated flare gas production of 303.71 Mcf/d compared to 303.98 reported by Weatherly. Weatherly's reported GWR of 22.95 SCF/separator barrel then results from dividing this by the brine turbine derived rate of 13,248 bpd at separator pressure and temperature.

Flare Line Gas Gravity and Heating Value

On October 8, 1980 flare line gas samples were collected for analysis by both IGT and Anacon. Results of these independent analyses are:

	<u>IGT</u>	<u>Anacon</u>
Dry Gas Gravity	.7006	.6787
Heating Value (BTU/SCF)	949.4	970.7

This modest difference is due to higher CO₂ content in the IGT analysis (11.18 vs. 9.13 mole percent) and higher content of C5 + hydrocarbons in the Anacon analysis (0.16 vs. 0.07 mole percent). The variation in gas analyses is

believed by IGT to be due to a difference in sampling procedure. Namely, IGT preheats sample pressure vessels to above brine temperature (277°F on 10/8/80) to minimize condensation of heavy hydrocarbons or water, which subsequently absorb CO₂ from the gas.

Gross Flare Line Gas Flow

All relevant parameters were quite steady between 1915 and 2015 hours on 10/8/80 except differential pressure (ΔP) across the orifice. The average of the square roots of ΔP 's reported every five minutes was squared to yield a value of 11.33 inches of water. Supercompressibility ($F_{pv} = \sqrt{\frac{1}{z}}$) at orifice meter temperature (238°F) and pressure (790 psig) was 1.0189 and total gas flow through the flare line was 278.9 MCF/d for a pressure base of 14.73 psia.

Reduce Total Gas Flow Due to Steam

At the orifice meter temperature of 238°F, the vapor pressure of water is 24 psia. Thus, dry gas production is estimated to be

$$\frac{(790) + (14.73) - 24}{(790) + (14.73)} (278.9) = 270.6 \text{ McF/d}$$

Metered Brine Rate Corrected to 14.73 psia and 60°F

For the separator pressure of 790 psig, and the brine temperature of 277°F, IGT's correction procedure reduces brine rate from 13,248 separator barrels per day to 12,514 stock tank barrels (STB) per day.

Calculated Flare Line Gas to Brine Ratio

Using the dry gas and corrected brine rates developed above, this ratio is $\frac{270,600}{12,514} = 21.6 \text{ SCF/STB}$.

Add Gas Remaining in Solution in Brine to the Disposal Well

For the low salinity "Wells of Opportunity" IGT has been using the computer algorithm developed by Systems, Science and Software for methane solubility in distilled water. This was selected on the basis of the best fit of published empirical expressions to date from flashing brine during the test of the Wainoco P.R. Girouard No. 1 well. That algorithm gives a value of 5.92 SCF/STB for separator pressure and brine temperature. However, the value of 5.4 SCF/STB measured by flashing a Pleasant Bayou sample collected at 2005 hours on 10/8/80 is more realistic.

Thus, the ratio of produced gas to produced brine at 2000 hrs on 10/8/80 is estimated to be $21.6 + 5.4 = 27.0$ SCF/BBL. The accuracy of methods used to develop this estimate has not been established. A particularly significant question is whether brine to the disposal well contains gas bubbles that would have not been detected with IGT's sampling procedure.

Whether the particular hour examined in detail is representative of the 45 day test has been examined by using one hour average ΔP of 11.33 inches of water in the previously described Weatherly field calculation procedure. The result is 22.30 cubic feet of flared gas per measured barrel of brine. In contrast, dividing the reported cumulative gas production by cumulative brine production for the 45 day test* yields and overall ratio of 20.28 cubic feet of flared gas per barrel of brine at separator pressure and temperature.

* Values used are from the Fennix and Scisson daily report for October 31, 1980.

LABORATORY STUDY OF METHANE SOLUBILITY IN PLEASANT BAYOU BRINE

Dr. Charles Blount has studied methane solubility in a Pleasant Bayou well brine sample collected in December 1979. His work was at temperatures and pressures that bracket actual reservoir conditions. Data from that work was interpreted using his revised procedure giving lower values than his previously published values for methane solubility. Using an equation provided by Dr. Blount specifically for Pleasant Bayou brine yields the estimate of 27.8 to 28.3 SCF/STB for methane solubility in the Pleasant Bayou aquifer. The equation is $\log_e (\text{SCF/BBL}) = -4.40 + 0.77403 \log_e P + .003374T - (4.48 \times 10^{-5})P$ where P is in psia and T is in degrees fahrenheit. Note that this equation does not contain salinity terms and is applicable only to Pleasant Bayou brine from the perforated interval between 14,644 and 14,704 feet. Dr. Blount's report to IGT is appended to this report and contains a revised equation which can be applied from 212°-450°F, 200-22,500 psi and 0.3 to 25 weight percent NaCl. The solubility values obtained on Pleasant Bayou brines are slightly lower than would be predicted by his general equation derived from NaCl solutions.

COMPARISON OF FIELD AND LABORATORY GAS TO BRINE RATIOS

If one considers only overall ratios of dry gas, independent of composition, to produced brine, both the IGT field data analysis and Dr. Blounts laboratory studies appear to be converging to about 27-28 SCF/BBL. However, as with the Wainoco P.R. Girouard test, the field result is below the laboratory result by just enough to be frustrating in relation to identified probable errors.

When gas composition is taken into account, conclusions regarding saturation of in-situ reservoir brine become more elusive as is apparent from Table 1.

Table 1. GAS CONTENT OF BRINE

	Field Data (2000 hrs, 10/8/80)						Blount
	Flare Gas		Gas in Disposal Brine		Produced Gas		SCF/STB
	Mole %	SCF/STB	Mole %	SCF/STB	Mole %	SCF/STB	
All Components	100	21.6	100	5.4	100	27.0	-
CO ₂	11.19	2.41	25.99	1.40	14.15	3.82	-
CH ₄	83.26	17.98	69.57	3.76	80.52	21.74	27.8-28.3
All Hydrocarbons	88.21	19.05	73.46	3.97	85.26	23.02	-

The methane content of produced brine is only about 78 percent of the saturation value for pure methane found by Dr. Blount. Thus the aquifer is gas saturated only,

if gases replace one another in solution or;

if field results contain a substantial error due to a phenomenon such as improper separator operation so that gas bubbles are entrained in brine to the disposal well.

One important comparison to make is that of Professor Blount's results with the Haas empiricism. Haas' empiricism is based on the work of several investigators, but primarily those of Culberson and McKetta and Sultanov for gas solubilities in pure water and O'Sullivan and Smith for salting-out coefficients. The more recent work of Price on pure water was unavailable to Haas. Table 2 makes such a comparison for several pressures and temperatures measured during Pleasant Bayou tests.

Except for the values at the separator pressure there is quite good agreement. There is also good agreement between Haas' empiricism and Price's data for pure water. For reasons to be explained below it will be assumed that Blount's value of 5.4 SCF/bbl is correct. It is strikingly identical to the value measured for total gas in the disposal brine. (See Table 1.) The influence on the solubility of one gas by the presence of another in these temperature and pressure regimes needs to be evaluated.

Two pieces of evidence exist which say that the methane solubility is decreased by the presence of other gases. The first is an analysis by Weatherly Laboratories of the bubble point in Wainoco P.R. Girouard fluids. The observed total gas solubility is the same as that predicted by the Haas empiricism for methane alone. Methane comprises about 90% of the gas from the Wainoco. Professor Blount also has some data on the influence of CO₂ on methane solubility. His data indicate that for 5 weight percent NaCl solutions methane solubility is slightly increased for small amounts of CO₂ but is dramatically decreased for amounts of CO₂ in excess of 15 mole percent.

The results of Amirjafari and Campbell on the other hand, show that up to 8,000 psi and 220°F the solubility of mixtures of light hydrocarbons is greater than that of pure components. These are solubilities in pure water. Culberson and McKetta, in discussing the data of Dodson and Standing, note that the natural gas solubilities at higher pressures is between the pure

Table 2

CALCULATED METHANE SOLUBILITY FOR TEMPERATURE AND PRESSURES
MEASURED DURING PLEASANT BAYOU WELL TESTING

Depth ft.	Pressure psia	Temperature Degrees F	Methane Solubility	
			Blount	Haas (6)
14674 (1)	11241 (2)	300 (2)	27.89	29.73
14674 (1)	11166 (3)	308 (3)	28.60	30.75
14674 (1)	10478 (4)	308 (3)	28.08	29.66
Surface	815 (5)	277 (5)	5.40	3.72

±1 SCF/BBL

- (1) The depth of 14,674 feet (reference from KB 33 feet above BHF) for the center of the perforated interval is from the document:

PLEASANT BAYOU GEOPRESSURE GEOTHERMAL PROJECT
ON SITE ENGINEERING REPORT
J. DONALD CLARK
JOHN E. STEVENS

SUMMARY OF TESTING TO NOVEMBER 20, 1979

- (2) Pressure and temperatures at 14,674 feet from interpolation of November 13-15, 1979 gradient data in the above referenced report.
- (3) Pressure and temperature from extrapolation to 14,674 feet from the measurements reported at 14,000 and 14,560 feet in the Reservoir Data, Inc. Field Test Data sheet for September 16, 1980.
- (4) Pressure and temperature at 14,674 feet estimated from the Reservoir Data, Inc. Field Test Data sheet for 2000 hours on October 8, 1980 assuming
- pressure gradient at depth = 0.44 psi/ft.
 - temperature gradient at depth = 15 degrees F/1000 ft.
 - sensor depth = 14,560 ft.
- (5) Separator pressure and temperature values reported by Weatherly Engineering for 2005 hours on October 8, 1980.
- (6) Calculated using a salinity of 130,000 mg/l and brine density of 66.2 lbs/ft.³

methane and pure ethane solubilities. No conclusions can be drawn at this time about formation saturation until the question of the solubility of mixtures is resolved.

The discrepancy in the low pressure comparison between Blount and Haas mentioned above is due primarily to the fact that Haas' low pressure, high temperature values are based on Culberson and McKetta data from 1951. A paper published in 1960 by Davis and McKetta repeated the measurement at low pressures. Figure 3 compares Culberson and McKetta solubility values with Davis and McKetta solubility values along the 220°F isotherm. At 400 psi the difference in solubility is ~0.5 SCF/bbl, at 800 psi the difference is ~1/SCF/bbl. Haas' empiricism is based on the lower solubilities. Therefore, for the conditions in Table 2, Blount's value at 815 psi is presumed more valid than Haas' value.

REFERENCES

1. Amirijafari, B. and Campbell, J. M., "Solubility of Gaseous Hydrocarbon Mixtures in Water," Trans. AIME 253 21, 1972.
2. Blount, C. W. et. al., "Methane Solubility in Aqueous NaCl Solutions at Elevated Temperatures and Pressures," Proceedings - Fourth U. S. Gulf Coast Geopressured-Geothermal Energy Conference, pp. 1225, October 1979.
3. Culbertson, O. L. and McKetta, J. J., Jr., "Phase Equilibria in Hydrocarbon-Water Systems: III - The Solubility of Methane in Water at Pressures to 10,000 psia," Pet Trans. AIME 192, 223 (1951).
4. Davis, J. E. and McKetta, J. J., "Solubility of Methane in Water," Petrol. Refiner 39, (3), 205, 1960.
5. Haas, J. L., Jr., "An Empirical Equation with Tables of Smoothed Solubilities of Methane in Water and Aqueous Sodium Chemical Fractions up to 25 Weight Percent, 360°C, and 138MPa," U. S. Geological Survey, Open File Report 78-1004.
5. Neal, J., Weatherly Laboratories, Inc., Lafayette, Louisiana, Private Communication, 1980.
6. Price, L. C., American Assoc. of Petroleum Geologists Bulletin 63 (9), 1527 (1979).
7. O'Sullivan, T. D. and Smith, N. O., "The Solubility and Partial Molar Volume of Nitrogen and Methane in Water and in Aqueous Sodium Chloride from 50 to 125 and 100 to 600 Atm," J. Phys. Chem. 74, 1460 (1970).
8. Sultanov, R. C., Skripka, V. C. and Namiot, A. Yu., "Solubility of Methane in Water at High Temperatures and Pressure." Gazova Promyshlennost 17, 6 (1972). Data Provided from Price reference #10,

Idaho State University

Pocatello, Idaho

83209

College of Liberal Arts
Department of Geology

Report for Institute of Gas Technology

Purchase Order Number S542544

Solubility of Methane in Waters from Pleasant Bayou Well No. 2.

The solubility of methane gas was determined in a sample of Pleasant Bayou well water supplied by the Institute of Gas Technology. This fluid contained some reddish colored fine grained precipitate resembling ferric hydroxide. This precipitate was removed by filtration before being put into the experimental equipment. The resulting solution had a density of 1.0914 g/ml while the unfiltered solution was 1.09227. The salinity of the solutions is about 130 grams/liter.

The filtered solution was put into a teflon sample container which was then installed in a pressure vessel. The assembled equipment was pressure tested, put into a rocking oven and heated. Methane was then injected into the sample container and pressure vessel. The equipment was then rocked for a period of time, 8 to 24 hours. Methane was reinjected to obtain the desired pressure. Rocking was continued. Samples were then taken at intervals of time and analyzed. Sample weights were determined on an analytical balance. The quantity of methane was determined by pressure measurements using high precision test gauges obtained from Matheson. Pressure was measured to ± 0.04 psi. Methane concentrations in moles per kilogram were calculated using the ideal gas law. The volume of gas was computed from the known volume of the flask, the calculated volume of liquid sample, and the volume of the test gauge. A correction was also made for the compression of air present in the flask before sampling. The injection of a liquid would cause pressure in the flask to increase due to reduced volume alone in addition to any gasses exsolved from the liquid.

In the derived empirical equation, methane concentrations are expressed as the logarithms to the base e of concentration units given in standard cubic feet of gas per petroleum barrel. Examination of all 81 points show that 10 data points had larger than expected standard deviations. Low values could be the result of gas losses from sample vessels before measurement. High values could represent a procedural error. Gasses not completely bled out of vessel prior to next determination or a gas bubble in the system was swept out during sampling. The expected uncertainty in the calculated methane concentration would be about $\pm \frac{1}{2}$ SCF. Solubilities calculated from the equation differ from the measured values by $\frac{1}{2}$ to 1 SCF in most cases. The fit of observed data to the equation line is shown in figure 1. The ten previously mentioned high and low values have been deleted.

The solubilities of methane observed in Pleasant Bayou brines were compared

to the solubilities obtained in NaCl solutions at a salinity of 135 grams/liter. The values in NaCl solution were obtained from an empirical equation derived from measurements in NaCl solutions. This equation is also given in table 3. The NaCl solution equation has an overall uncertainty of about + 8% of the value. Measurements in NaCl solutions are consistently higher by a slight amount compared to measurements in well solutions. The difference is less than the standard deviations of either equation. These differences are thus probably not really significant.

Concentrations of gasses reported from Pleasant Bayou No. 2 well total 27.0 SCF/Bbl (letter dated Feb. 24, 1981). This estimate includes 21.7 SCF of methane, 1.3 SCF of other hydrocarbon gasses and 3.8 SCF of CO₂. This data has been plotted in figure 2. If CO₂ simply displaced methane from solution on a mole for mole basis, methane concentrations would follow a straight line reduction with increasing CO₂ (simple displacement line (S.D.L.)). We do not have any measurements of the effect of CO₂ on methane concentration at experimental conditions approximating those at formation levels in the Pleasant Bayou No. 2 well. The closest similar data is at 302°F, 5000 psi and at a salinity of 51.7 grams per liter. Calculated solubility of methane in solutions lacking CO₂ is 28 SCF/Bbl. The curves have been proportionately adjusted to fit 27 SCF. It is evident that adding CO₂ increases the total gas in solution and only gradually reduces methane concentration at least up to 10% CO₂ in the gas. At higher concentrations, CO₂ really suppresses methane solubility while the total gas content increases significantly. Thus at 11% CO₂ we would expect little if any reduction in methane concentration vs solution lacking CO₂ (about 1 SCF less). What is even more interesting is the reference to J. M. Campbell's work showing that solubilities of mixtures of light hydrocarbon gasses is greater than that of pure components. If this is true at higher temperatures and pressures, then the total hydrocarbon gasses should be greater than the indicated 27-28 SCF/Bbl in solutions lacking CO₂.

The tentative conclusions that we can make here based on the information presently available is that the concentration of methane and hydrocarbon gas totals is less than what should be there at the CO₂ concentration involved. There is a shortfall of at least 3 SCF per barrel relative to the methane curve in figure 2 based upon effect of CO₂ at 5000 psi in 5% NaCl. There would be an additional shortfall in methane if other hydrocarbons were to actually enhance methane concentrations. This would suggest that the Pleasant Bayou waters in the well may be slightly undersaturated with methane. There are two specific effects that need further evaluation. First we need to know more about the effect of CO₂ at the appropriate conditions of 302°F, 11,000 psi and 130 g/liter salinity. Second we need to determine independently what effect ethane has upon methane concentrations in saturated solutions. These experimental parameters will be employed as soon as we can possibly get equipment together.

Table I. Experimental Results - Solubility of Methane in Pleasant Bayou
No. 2 Well Brines.

ROW	TFAREN	PSI	SCF/BL	CALCH4
* 1 *	203.00000	12081.66406	20.56000	21.00953
* 2 *	200.29999	11994.64258	18.76000	20.76665
* 3 *	200.29999	11994.64258	21.61000	20.76665
* 4 *	203.00000	11994.64258	20.47000	20.98095
* 5 *	198.31998	9108.38672	20.36000	19.06415
* 6 *	198.31998	9108.38672	19.64000	19.06415
* 7 *	194.00000	9137.39453	20.51000	18.74704
* 8 *	194.00000	9137.39453	19.38000	18.74704
* 9 *	196.87997	9137.39453	19.11000	18.97328
* 10 *	197.95999	5134.34473	13.92000	14.36617
* 11 *	197.95999	5134.34473	13.68000	14.36617
* 12 *	198.50000	5018.31445	12.60000	14.20597
* 13 *	198.50000	5018.31445	13.54000	14.20597
* 14 *	198.67999	2001.52441	8.60000	7.44561
* 15 *	199.03998	2030.53198	7.94000	7.54393
* 16 *	199.03998	2030.53198	8.28000	7.54393
* 17 *	199.03998	1058.77734	4.21000	4.45738
* 18 *	198.50000	1058.77734	4.16000	4.44320
* 19 *	198.50000	1058.77734	4.24000	4.44320
* 20 *	248.17999	11994.64258	24.11000	24.33393
* 21 *	248.00000	11951.13086	24.07000	24.30803
* 22 *	248.00000	11951.13086	24.22000	24.30803
* 23 *	248.00000	11893.11523	25.52000	24.28943
* 24 *	248.00000	12038.15430	25.49000	24.33508
* 25 *	248.00000	12038.15430	24.71000	24.33508
* 26 *	248.00000	9108.38672	21.85000	22.75832
* 27 *	249.79999	9006.85938	21.23000	22.79897
* 28 *	250.69998	9108.38672	23.44000	22.94310
* 29 *	250.69998	9108.38672	22.81000	22.94310
* 30 *	250.25000	5032.81836	18.44000	17.53644
* 31 *	250.25000	5032.81836	16.49000	17.53644
* 32 *	250.25000	5003.81055	18.55000	17.47985
* 33 *	250.25000	5003.81055	16.32000	17.47985
* 34 *	248.89999	2059.53955	9.88000	9.68718
* 35 *	250.25000	2001.52441	9.23000	9.54066
* 36 *	250.25000	2001.52441	9.13000	9.54066
* 37 *	250.25000	2001.52441	10.63000	9.54066
* 38 *	250.25000	2001.52441	9.11000	9.54066
* 39 *	250.25000	2001.52441	8.96000	9.54066
* 40 *	250.25000	1000.76221	6.19000	5.60288
* 41 *	250.25000	1000.76221	5.38000	5.60288
* 42 *	250.25000	1000.76221	5.65000	5.60288
* 43 *	250.25000	1000.76221	5.61000	5.60288
* 44 *	301.09998	12299.22266	29.69000	27.42771
* 45 *	301.09998	12299.22266	28.95000	27.42771
* 46 *	301.09998	12081.66406	26.70000	27.38019
* 47 *	301.09998	12081.66406	26.85000	27.38019
* 48 *	301.09998	11994.64258	26.70000	27.35918
* 49 *	301.09998	11994.64258	28.61000	27.35918
* 50 *	300.01996	9006.85938	24.24000	25.78226
* 51 *	304.25000	9064.87500	26.47000	26.03215
* 52 *	304.25000	9050.37109	24.42000	26.02061
* 53 *	299.47992	5076.33008	19.57000	20.35548
* 54 *	299.47992	5076.33008	19.06000	20.35548
* 55 *	299.47992	5076.33008	20.23000	20.35548
* 56 *	299.47992	5076.33008	19.45000	20.35548
* 57 *	301.09998	2001.52441	12.35000	11.51192
* 58 *	301.09998	2001.52441	11.97000	11.51192
* 59 *	304.25000	1015.26599	7.25000	7.12098
* 60 *	297.67993	1000.76221	8.03000	6.87442
* 61 *	298.39996	1000.76221	7.90000	6.89318
* 62 *	298.39996	1000.76221	7.58000	6.89318
* 63 *	301.09998	507.63300	3.92000	4.13682
* 64 *	301.09998	269.77063	2.34000	2.51426
* 65 *	301.09998	269.77063	2.07000	2.51426
* 66 *	301.63995	259.61798	2.12000	2.44520
* 67 *	301.63995	259.61798	2.09000	2.44520
* 68 *	301.09998	249.46530	2.59000	2.36270
* 69 *	301.09998	249.46530	2.31000	2.36270
* 70 *	300.20001	104.42735	1.28000	1.17134
* 71 *	300.20001	104.42735	1.34000	1.17134

Table 2. Comparison of Solubilities of Methane in Pleasant Bayou No. 2 Well Waters and in NaCl Solution at a Salinity of 135 Grams per Liter.

Temp. °F	Pressure psi	Methane SCF/Bbl		Temp. °F	Pressure psi	Methane SCF/Bbl	
		Pb No. 2	NaCl Sol.			Pb No. 2	NaCl Sol.
200	12,000	20.7	22.5	260	12,000	25.1	26.7
"	10,000	19.8	20.6	"	10,000	24.2	24.4
"	8,000	18.2	18.5	"	8,000	22.5	21.8
"	6,000	15.8	16.0	"	6,000	19.9	18.6
"	4,000	12.4	12.9	"	4,000	15.9	14.8
"	2,000	7.5	8.7	"	2,000	9.9	9.8
"	1,000	4.3	5.8	"	1,000	5.9	6.4
"	500	2.4	3.9	"	500	3.4	4.2
220	12,000	22.3	23.6	280	12,000	26.3	28.6
"	10,000	21.4	21.7	"	10,000	25.4	26.1
"	8,000	19.7	19.4	"	8,000	23.8	23.2
"	6,000	17.2	16.7	"	6,000	21.0	19.8
"	4,000	13.6	13.4	"	4,000	16.9	15.6
"	2,000	8.3	9.0	"	2,000	10.7	10.3
"	1,000	4.8	6.0	"	1,000	6.4	6.7
"	500	2.7	3.9	"	500	3.7	4.3
240	12,000	23.8	25.1	300	12,000	27.3	30.8
"	10,000	22.8	23.0	"	10,000	26.5	28.0
"	8,000	21.2	20.5	"	8,000	24.8	24.8
"	6,000	18.6	17.6	"	6,000	22.1	21.1
"	4,000	14.7	14.0	"	4,000	17.9	16.6
"	2,000	9.1	9.4	"	2,000	11.5	10.9
"	1,000	5.3	6.2	"	1,000	6.9	7.0
"	500	3.0	4.0	"	500	4.1	4.5

Table 3. Empirical Equations for the Solubility of Methane in Aqueous Solutions.

A. Pleasant Bayou No. 2 brines.

$$\log_e CH_4 = A + Bt + Cp + D\log_e p + Et\log_e p + Ft^2.$$

CH_4 is expressed in SCF per petroleum barrel.

p is pressure in psi.

t is temperature in degrees Fahrenheit.

A-F are empirical parameters derived by least squares regression.

$$\begin{aligned} A &= -7.45 \\ B &= 1.6067E-02 \\ C &= 5.8446E-05 \\ D &= 1.0622 \\ E &= -8.3876E-04 \\ F &= -1.0878E-05 \end{aligned}$$

Adjusted Multiple R = 0.996

Standard deviation of Residuals in $\log_e$ of CH_4 values = 0.075

71 observations

B. NaCl Solutions.

$$\log_e CH_4 = A + Bt + Cp + D\log_e p + Et\log_e p + Ft^2\log_e p + GS + Hst^{\frac{1}{2}} + Is^2 + Jt^2s^2 + Ks\log_e p + Lts\log_e p + Mt^2s\log_e p.$$

CH_4 is in SCF per petroleum barrel.

p is pressure in psi.

s is grams per liter of solution at S. T. P.

t is temperature in degrees Fahrenheit.

A-M are empirical parameters derived by least squares regression.

$$\begin{aligned} A &= -3.1720 \\ B &= 4.7219E-03 \\ C &= -1.2292E-05 \\ D &= 6.9761E-01 \\ E &= -4.8596E-04 \\ F &= 8.5455E-07 \\ G &= 2.4434E-02 \\ H &= -1.7581E-03 \\ I &= -8.2950E-06 \\ J &= 1.1460E-10 \\ K &= -1.6687E-03 \\ L &= 8.7371E-06 \\ M &= -8.8269E-09 \end{aligned}$$

Fig. 1

fig. 2

APPENDIX F.

Tables of Absolute Viscosity of NaCl Solutions

ABSOLUTE VISCOSITY(CP) OF NaCl SOLUTIONS
PRESSURE = 1000Psi

FILE NAME : VIS10

TEMP. DEG.F	SALINITY, percent by weight										
	0	2.5	5.0	7.5	10.0	12.5	15.0	17.5	20.0	22.5	25.0
150	0.4319	0.4532	0.4757	0.5021	0.5316	0.5648	0.6039	0.6703	0.7342	0.8100	0.9003
155	0.4155	0.4361	0.4580	0.4835	0.5119	0.5439	0.5816	0.6455	0.7070	0.7798	0.8667
160	0.4000	0.4201	0.4413	0.4660	0.4934	0.5243	0.5606	0.6222	0.6814	0.7516	0.8353
165	0.3856	0.4051	0.4257	0.4496	0.4760	0.5059	0.5409	0.6004	0.6574	0.7251	0.8057
170	0.3720	0.3910	0.4109	0.4341	0.4597	0.4886	0.5224	0.5798	0.6349	0.7002	0.7780
175	0.3592	0.3777	0.3971	0.4196	0.4444	0.4723	0.5050	0.5604	0.6136	0.6767	0.7518
180	0.3471	0.3652	0.3840	0.4058	0.4299	0.4569	0.4886	0.5422	0.5936	0.6545	0.7272
185	0.3357	0.3533	0.3717	0.3929	0.4162	0.4424	0.4730	0.5249	0.5747	0.6336	0.7039
190	0.3250	0.3422	0.3601	0.3807	0.4033	0.4287	0.4584	0.5086	0.5568	0.6139	0.6819
195	0.3148	0.3316	0.3490	0.3691	0.3911	0.4157	0.4445	0.4932	0.5399	0.5952	0.6611
200	0.3052	0.3216	0.3386	0.3581	0.3795	0.4034	0.4314	0.4786	0.5239	0.5775	0.6414
205	0.2960	0.3121	0.3287	0.3477	0.3685	0.3917	0.4189	0.4648	0.5087	0.5607	0.6227
210	0.2873	0.3031	0.3193	0.3378	0.3581	0.3807	0.4071	0.4516	0.4943	0.5448	0.6049
215	0.2791	0.2945	0.3104	0.3285	0.3482	0.3702	0.3958	0.4391	0.4806	0.5296	0.5881
220	0.2713	0.2864	0.3019	0.3195	0.3388	0.3602	0.3852	0.4273	0.4676	0.5153	0.5721
225	0.2638	0.2787	0.2938	0.3111	0.3298	0.3507	0.3750	0.4160	0.4552	0.5016	0.5568
230	0.2568	0.2713	0.2861	0.3030	0.3213	0.3416	0.3653	0.4052	0.4434	0.4885	0.5423
235	0.2500	0.2643	0.2788	0.2953	0.3132	0.3330	0.3561	0.3950	0.4321	0.4761	0.5285
240	0.2436	0.2576	0.2718	0.2879	0.3054	0.3248	0.3473	0.3852	0.4214	0.4643	0.5153
245	0.2374	0.2512	0.2652	0.2809	0.2980	0.3169	0.3389	0.3759	0.4112	0.4530	0.5027
250	0.2315	0.2451	0.2588	0.2742	0.2909	0.3094	0.3309	0.3670	0.4014	0.4422	0.4907
255	0.2259	0.2393	0.2527	0.2678	0.2842	0.3022	0.3232	0.3584	0.3921	0.4318	0.4792
260	0.2206	0.2337	0.2469	0.2617	0.2777	0.2954	0.3159	0.3503	0.3831	0.4220	0.4682
265	0.2155	0.2284	0.2413	0.2559	0.2715	0.2888	0.3089	0.3425	0.3746	0.4125	0.4577
270	0.2105	0.2232	0.2360	0.2503	0.2656	0.2825	0.3022	0.3350	0.3664	0.4035	0.4476
275	0.2058	0.2184	0.2309	0.2449	0.2600	0.2765	0.2957	0.3279	0.3586	0.3948	0.4379
280	0.2013	0.2137	0.2260	0.2398	0.2545	0.2708	0.2896	0.3210	0.3510	0.3865	0.4287
285	0.1970	0.2092	0.2213	0.2348	0.2493	0.2652	0.2836	0.3145	0.3438	0.3785	0.4198
290	0.1929	0.2049	0.2168	0.2301	0.2443	0.2599	0.2780	0.3082	0.3369	0.3709	0.4113
295	0.1889	0.2007	0.2125	0.2255	0.2395	0.2548	0.2725	0.3021	0.3303	0.3636	0.4032
300	0.1850	0.1967	0.2083	0.2212	0.2349	0.2499	0.2673	0.2963	0.3239	0.3565	0.3953
305	0.1814	0.1929	0.2043	0.2170	0.2305	0.2452	0.2622	0.2907	0.3178	0.3498	0.3878
310	0.1778	0.1892	0.2005	0.2129	0.2262	0.2407	0.2574	0.2853	0.3119	0.3432	0.3805
315	0.1744	0.1857	0.1968	0.2091	0.2221	0.2363	0.2528	0.2802	0.3062	0.3370	0.3736
320	0.1712	0.1823	0.1933	0.2053	0.2181	0.2322	0.2483	0.2752	0.3008	0.3310	0.3668
325	0.1680	0.1790	0.1898	0.2017	0.2144	0.2281	0.2440	0.2704	0.2955	0.3251	0.3604
330	0.1650	0.1759	0.1865	0.1983	0.2107	0.2242	0.2398	0.2658	0.2904	0.3196	0.3542
335	0.1621	0.1728	0.1834	0.1949	0.2072	0.2205	0.2358	0.2613	0.2856	0.3142	0.3482
340	0.1592	0.1699	0.1803	0.1917	0.2038	0.2169	0.2319	0.2570	0.2809	0.3090	0.3424
345	0.1565	0.1670	0.1773	0.1886	0.2005	0.2134	0.2282	0.2529	0.2763	0.3039	0.3368
350	0.1539	0.1643	0.1745	0.1856	0.1973	0.2100	0.2246	0.2489	0.2719	0.2991	0.3314

ABSOLUTE VISCOSITY(cp) OF NaCl SOLUTIONS
PRESSURE = 2000psi

FILE NAME : VIS20

TEMP. DEG.F	SALINITY, percent by weight										
	0	2.5	5.0	7.5	10.0	12.5	15.0	17.5	20.0	22.5	25.0
150	0.4335	0.4548	0.4775	0.5040	0.5335	0.5669	0.6061	0.6728	0.7369	0.8130	0.9036
155	0.4171	0.4378	0.4598	0.4854	0.5139	0.5460	0.5839	0.6481	0.7098	0.7829	0.8702
160	0.4017	0.4219	0.4432	0.4680	0.4955	0.5265	0.5630	0.6249	0.6843	0.7548	0.8388
165	0.3873	0.4069	0.4276	0.4516	0.4782	0.5081	0.5433	0.6030	0.6604	0.7283	0.8093
170	0.3737	0.3928	0.4129	0.4362	0.4619	0.4909	0.5249	0.5825	0.6378	0.7034	0.7816
175	0.3610	0.3796	0.3991	0.4216	0.4466	0.4746	0.5075	0.5632	0.6167	0.6800	0.7555
180	0.3489	0.3671	0.3860	0.4079	0.4321	0.4593	0.4911	0.5450	0.5967	0.6579	0.7309
185	0.3375	0.3553	0.3737	0.3950	0.4185	0.4448	0.4756	0.5278	0.5778	0.6371	0.7077
190	0.3268	0.3441	0.3621	0.3828	0.4056	0.4311	0.4610	0.5115	0.5599	0.6173	0.6857
195	0.3166	0.3335	0.3511	0.3712	0.3934	0.4181	0.4471	0.4961	0.5430	0.5987	0.6649
200	0.3070	0.3235	0.3406	0.3603	0.3818	0.4058	0.4340	0.4815	0.5270	0.5810	0.6452
205	0.2979	0.3140	0.3308	0.3499	0.3708	0.3942	0.4215	0.4677	0.5119	0.5642	0.6266
210	0.2892	0.3050	0.3214	0.3400	0.3604	0.3831	0.4097	0.4546	0.4975	0.5483	0.6088
215	0.2810	0.2965	0.3125	0.3306	0.3505	0.3726	0.3985	0.4421	0.4838	0.5332	0.5920
220	0.2732	0.2884	0.3040	0.3217	0.3411	0.3627	0.3878	0.4302	0.4708	0.5188	0.5760
225	0.2657	0.2806	0.2959	0.3133	0.3321	0.3532	0.3777	0.4189	0.4584	0.5051	0.5607
230	0.2586	0.2733	0.2882	0.3052	0.3236	0.3441	0.3680	0.4082	0.4466	0.4921	0.5462
235	0.2519	0.2662	0.2809	0.2975	0.3155	0.3355	0.3587	0.3979	0.4353	0.4797	0.5324
240	0.2454	0.2595	0.2739	0.2901	0.3077	0.3272	0.3499	0.3881	0.4246	0.4678	0.5192
245	0.2393	0.2532	0.2672	0.2831	0.3003	0.3194	0.3415	0.3788	0.4144	0.4565	0.5066
250	0.2334	0.2470	0.2609	0.2764	0.2933	0.3119	0.3335	0.3699	0.4046	0.4457	0.4946
255	0.2278	0.2412	0.2548	0.2700	0.2865	0.3047	0.3259	0.3614	0.3953	0.4354	0.4831
260	0.2224	0.2356	0.2490	0.2639	0.2800	0.2978	0.3185	0.3532	0.3863	0.4255	0.4721
265	0.2173	0.2303	0.2434	0.2581	0.2738	0.2913	0.3115	0.3454	0.3778	0.4160	0.4615
270	0.2124	0.2252	0.2380	0.2524	0.2679	0.2850	0.3048	0.3379	0.3696	0.4070	0.4515
275	0.2077	0.2203	0.2329	0.2471	0.2622	0.2790	0.2983	0.3308	0.3617	0.3983	0.4418
280	0.2031	0.2156	0.2280	0.2419	0.2568	0.2732	0.2922	0.3239	0.3542	0.3900	0.4326
285	0.1988	0.2111	0.2233	0.2370	0.2516	0.2677	0.2862	0.3173	0.3470	0.3820	0.4237
290	0.1947	0.2068	0.2188	0.2322	0.2466	0.2623	0.2806	0.3110	0.3401	0.3744	0.4152
295	0.1907	0.2026	0.2145	0.2277	0.2418	0.2572	0.2751	0.3050	0.3334	0.3670	0.4070
300	0.1868	0.1986	0.2103	0.2233	0.2372	0.2523	0.2699	0.2991	0.3270	0.3600	0.3991
305	0.1832	0.1948	0.2063	0.2191	0.2327	0.2476	0.2648	0.2935	0.3209	0.3532	0.3916
310	0.1796	0.1911	0.2025	0.2151	0.2284	0.2431	0.2600	0.2882	0.3150	0.3467	0.3843
315	0.1762	0.1876	0.1988	0.2112	0.2243	0.2387	0.2553	0.2830	0.3093	0.3404	0.3773
320	0.1729	0.1842	0.1952	0.2074	0.2204	0.2345	0.2508	0.2780	0.3038	0.3343	0.3706
325	0.1698	0.1809	0.1918	0.2038	0.2166	0.2305	0.2465	0.2732	0.2986	0.3285	0.3641
330	0.1667	0.1777	0.1885	0.2004	0.2129	0.2266	0.2424	0.2686	0.2935	0.3229	0.3579
335	0.1638	0.1747	0.1853	0.1970	0.2094	0.2229	0.2383	0.2641	0.2886	0.3175	0.3519
340	0.1610	0.1717	0.1823	0.1938	0.2060	0.2192	0.2345	0.2598	0.2839	0.3123	0.3461
345	0.1582	0.1689	0.1793	0.1907	0.2027	0.2158	0.2307	0.2557	0.2794	0.3073	0.3405
350	0.1556	0.1662	0.1764	0.1877	0.1995	0.2124	0.2271	0.2517	0.2750	0.3025	0.3351

ABSOLUTE VISCOSITY (CP) OF NaCl SOLUTIONS
PRESSURE = 3000Psi

FILE NAME : VIS30

TEMP. DEG.F	SALINITY, percent by weight										
	0	2.5	5.0	7.5	10.0	12.5	15.0	17.5	20.0	22.5	25.0
150	0.4351	0.4565	0.4793	0.5059	0.5355	0.5690	0.6084	0.6754	0.7397	0.8160	0.9070
155	0.4188	0.4396	0.4616	0.4874	0.5159	0.5482	0.5862	0.6507	0.7126	0.7861	0.8736
160	0.4034	0.4237	0.4450	0.4699	0.4976	0.5287	0.5654	0.6275	0.6872	0.7580	0.8424
165	0.3890	0.4087	0.4295	0.4536	0.4803	0.5104	0.5458	0.6057	0.6633	0.7316	0.8130
170	0.3755	0.3947	0.4148	0.4382	0.4641	0.4932	0.5274	0.5853	0.6409	0.7068	0.7853
175	0.3627	0.3814	0.4010	0.4237	0.4488	0.4769	0.5100	0.5660	0.6197	0.6834	0.7593
180	0.3507	0.3690	0.3880	0.4101	0.4343	0.4616	0.4936	0.5478	0.5997	0.6613	0.7347
185	0.3394	0.3572	0.3757	0.3971	0.4207	0.4472	0.4782	0.5306	0.5809	0.6405	0.7115
190	0.3286	0.3460	0.3641	0.3849	0.4078	0.4335	0.4635	0.5144	0.5631	0.6208	0.6895
195	0.3185	0.3355	0.3531	0.3734	0.3956	0.4205	0.4497	0.4990	0.5462	0.6021	0.6688
200	0.3088	0.3255	0.3427	0.3624	0.3841	0.4083	0.4366	0.4844	0.5302	0.5845	0.6491
205	0.2997	0.3160	0.3328	0.3521	0.3731	0.3966	0.4242	0.4706	0.5151	0.5677	0.6305
210	0.2911	0.3070	0.3234	0.3422	0.3627	0.3856	0.4123	0.4575	0.5007	0.5518	0.6127
215	0.2828	0.2985	0.3145	0.3328	0.3528	0.3751	0.4011	0.4450	0.4870	0.5367	0.5959
220	0.2750	0.2903	0.3060	0.3239	0.3434	0.3651	0.3904	0.4331	0.4740	0.5223	0.5799
225	0.2676	0.2826	0.2980	0.3154	0.3345	0.3556	0.3803	0.4218	0.4616	0.5086	0.5647
230	0.2605	0.2752	0.2903	0.3074	0.3259	0.3466	0.3706	0.4111	0.4498	0.4956	0.5501
235	0.2537	0.2682	0.2830	0.2997	0.3178	0.3379	0.3614	0.4008	0.4385	0.4832	0.5363
240	0.2473	0.2615	0.2760	0.2923	0.3100	0.3297	0.3526	0.3911	0.4278	0.4713	0.5231
245	0.2411	0.2551	0.2693	0.2853	0.3026	0.3218	0.3442	0.3817	0.4176	0.4600	0.5105
250	0.2352	0.2490	0.2629	0.2786	0.2956	0.3143	0.3361	0.3728	0.4078	0.4492	0.4985
255	0.2296	0.2431	0.2568	0.2722	0.2888	0.3072	0.3285	0.3643	0.3984	0.4388	0.4869
260	0.2242	0.2376	0.2510	0.2661	0.2823	0.3003	0.3211	0.3561	0.3895	0.4290	0.4759
265	0.2191	0.2322	0.2454	0.2602	0.2761	0.2937	0.3141	0.3483	0.3809	0.4195	0.4654
270	0.2142	0.2271	0.2401	0.2546	0.2702	0.2874	0.3074	0.3408	0.3727	0.4104	0.4553
275	0.2095	0.2222	0.2350	0.2492	0.2645	0.2814	0.3009	0.3337	0.3649	0.4018	0.4456
280	0.2049	0.2175	0.2300	0.2441	0.2591	0.2756	0.2947	0.3268	0.3573	0.3934	0.4364
285	0.2006	0.2130	0.2253	0.2391	0.2538	0.2701	0.2888	0.3202	0.3501	0.3854	0.4275
290	0.1964	0.2086	0.2208	0.2344	0.2488	0.2647	0.2831	0.3139	0.3432	0.3778	0.4190
295	0.1924	0.2045	0.2165	0.2298	0.2440	0.2596	0.2777	0.3078	0.3365	0.3704	0.4108
300	0.1886	0.2005	0.2123	0.2254	0.2394	0.2547	0.2724	0.3020	0.3301	0.3634	0.4029
305	0.1849	0.1967	0.2083	0.2212	0.2349	0.2500	0.2674	0.2964	0.3240	0.3566	0.3953
310	0.1814	0.1930	0.2045	0.2172	0.2307	0.2455	0.2625	0.2910	0.3181	0.3500	0.3881
315	0.1779	0.1894	0.2008	0.2133	0.2266	0.2411	0.2578	0.2858	0.3124	0.3437	0.3811
320	0.1747	0.1860	0.1972	0.2095	0.2226	0.2369	0.2533	0.2808	0.3069	0.3377	0.3743
325	0.1715	0.1827	0.1938	0.2059	0.2188	0.2328	0.2490	0.2760	0.3016	0.3319	0.3678
330	0.1684	0.1795	0.1905	0.2024	0.2151	0.2289	0.2449	0.2714	0.2965	0.3263	0.3616
335	0.1655	0.1765	0.1873	0.1991	0.2116	0.2252	0.2408	0.2669	0.2917	0.3209	0.3556
340	0.1627	0.1735	0.1842	0.1959	0.2082	0.2216	0.2370	0.2626	0.2869	0.3156	0.3498
345	0.1599	0.1707	0.1812	0.1927	0.2049	0.2181	0.2332	0.2584	0.2824	0.3106	0.3442
350	0.1573	0.1680	0.1784	0.1897	0.2017	0.2147	0.2296	0.2544	0.2780	0.3058	0.3388

ABSOLUTE VISCOSITY (CP) OF NaCl SOLUTIONS
PRESSURE = 4000 PSI

FILE NAME : VIS40

TEMP. DEG.F	SALINITY, percent by weight										
	0	2.5	5.0	7.5	10.0	12.5	15.0	17.5	20.0	22.5	25.0
150	0.4368	0.4583	0.4811	0.5078	0.5376	0.5711	0.6107	0.6779	0.7425	0.8191	0.9104
155	0.4205	0.4414	0.4635	0.4893	0.5180	0.5504	0.5886	0.6533	0.7155	0.7892	0.8772
160	0.4052	0.4255	0.4469	0.4719	0.4997	0.5310	0.5678	0.6302	0.6901	0.7612	0.8459
165	0.3908	0.4106	0.4314	0.4556	0.4825	0.5127	0.5482	0.6085	0.6663	0.7349	0.8166
170	0.3773	0.3965	0.4168	0.4403	0.4663	0.4955	0.5298	0.5880	0.6439	0.7101	0.7890
175	0.3645	0.3833	0.4030	0.4258	0.4510	0.4793	0.5125	0.5688	0.6228	0.6867	0.7630
180	0.3525	0.3709	0.3900	0.4122	0.4366	0.4640	0.4962	0.5506	0.6028	0.6647	0.7385
185	0.3412	0.3591	0.3777	0.3993	0.4230	0.4496	0.4807	0.5334	0.5840	0.6439	0.7153
190	0.3305	0.3479	0.3661	0.3871	0.4101	0.4359	0.4661	0.5172	0.5662	0.6242	0.6934
195	0.3203	0.3374	0.3551	0.3755	0.3979	0.4230	0.4523	0.5019	0.5493	0.6056	0.6726
200	0.3107	0.3274	0.3447	0.3646	0.3864	0.4107	0.4392	0.4873	0.5334	0.5880	0.6530
205	0.3016	0.3179	0.3349	0.3542	0.3754	0.3991	0.4268	0.4735	0.5182	0.5712	0.6343
210	0.2929	0.3090	0.3255	0.3444	0.3650	0.3881	0.4150	0.4604	0.5038	0.5553	0.6166
215	0.2847	0.3004	0.3166	0.3350	0.3551	0.3776	0.4037	0.4479	0.4902	0.5402	0.5998
220	0.2769	0.2923	0.3081	0.3261	0.3457	0.3676	0.3931	0.4360	0.4772	0.5258	0.5838
225	0.2694	0.2845	0.3000	0.3176	0.3368	0.3581	0.3829	0.4248	0.4648	0.5121	0.5686
230	0.2623	0.2772	0.2923	0.3095	0.3282	0.3490	0.3732	0.4140	0.4530	0.4991	0.5540
235	0.2556	0.2701	0.2850	0.3018	0.3201	0.3404	0.3640	0.4037	0.4417	0.4867	0.5402
240	0.2491	0.2634	0.2780	0.2945	0.3123	0.3322	0.3552	0.3940	0.4310	0.4748	0.5270
245	0.2429	0.2570	0.2713	0.2875	0.3049	0.3243	0.3468	0.3846	0.4207	0.4635	0.5144
250	0.2371	0.2509	0.2650	0.2808	0.2979	0.3168	0.3387	0.3757	0.4109	0.4527	0.5023
255	0.2314	0.2451	0.2589	0.2744	0.2911	0.3096	0.3311	0.3671	0.4016	0.4423	0.4908
260	0.2260	0.2395	0.2530	0.2682	0.2846	0.3027	0.3237	0.3590	0.3926	0.4324	0.4798
265	0.2209	0.2341	0.2474	0.2623	0.2784	0.2961	0.3167	0.3512	0.3841	0.4229	0.4692
270	0.2160	0.2290	0.2421	0.2567	0.2725	0.2898	0.3099	0.3437	0.3758	0.4139	0.4591
275	0.2112	0.2241	0.2370	0.2513	0.2668	0.2838	0.3035	0.3365	0.3680	0.4052	0.4494
280	0.2067	0.2194	0.2320	0.2462	0.2613	0.2780	0.2973	0.3296	0.3604	0.3968	0.4402
285	0.2024	0.2149	0.2273	0.2412	0.2561	0.2724	0.2914	0.3230	0.3532	0.3888	0.4313
290	0.1982	0.2105	0.2228	0.2365	0.2511	0.2671	0.2857	0.3167	0.3462	0.3812	0.4227
295	0.1942	0.2064	0.2185	0.2319	0.2462	0.2620	0.2802	0.3106	0.3396	0.3738	0.4145
300	0.1903	0.2024	0.2143	0.2275	0.2416	0.2571	0.2749	0.3048	0.3332	0.3667	0.4066
305	0.1866	0.1985	0.2103	0.2233	0.2372	0.2523	0.2699	0.2991	0.3270	0.3599	0.3990
310	0.1831	0.1948	0.2064	0.2192	0.2329	0.2478	0.2650	0.2937	0.3211	0.3534	0.3918
315	0.1797	0.1913	0.2027	0.2153	0.2287	0.2434	0.2603	0.2885	0.3154	0.3471	0.3847
320	0.1764	0.1878	0.1991	0.2116	0.2248	0.2392	0.2558	0.2835	0.3099	0.3410	0.3780
325	0.1732	0.1845	0.1957	0.2080	0.2210	0.2352	0.2515	0.2787	0.3046	0.3352	0.3715
330	0.1701	0.1814	0.1924	0.2045	0.2173	0.2313	0.2473	0.2741	0.2995	0.3296	0.3652
335	0.1672	0.1783	0.1892	0.2011	0.2137	0.2275	0.2433	0.2696	0.2946	0.3241	0.3592
340	0.1644	0.1753	0.1861	0.1979	0.2103	0.2239	0.2394	0.2653	0.2899	0.3189	0.3534
345	0.1616	0.1725	0.1831	0.1948	0.2070	0.2204	0.2357	0.2612	0.2853	0.3139	0.3478
350	0.1590	0.1697	0.1803	0.1917	0.2038	0.2170	0.2321	0.2571	0.2809	0.3090	0.3424

ABSOLUTE VISCOSITY (CP) OF NaCl SOLUTIONS
PRESSURE = 5000 psi

FILE NAME : VIS50

TEMP. DEG.F	SALINITY, percent by weight										
	0	2.5	5.0	7.5	10.0	12.5	15.0	17.5	20.0	22.5	25.0
150	0.4384	0.4600	0.4829	0.5098	0.5396	0.5733	0.6131	0.6805	0.7453	0.8222	0.9139
155	0.4222	0.4431	0.4654	0.4913	0.5201	0.5527	0.5909	0.6559	0.7184	0.7924	0.8807
160	0.4069	0.4273	0.4489	0.4740	0.5018	0.5332	0.5702	0.6329	0.6931	0.7645	0.8496
165	0.3926	0.4124	0.4333	0.4577	0.4846	0.5150	0.5507	0.6112	0.6693	0.7382	0.8203
170	0.3791	0.3984	0.4188	0.4424	0.4685	0.4978	0.5323	0.5908	0.6469	0.7134	0.7927
175	0.3663	0.3852	0.4050	0.4279	0.4532	0.4817	0.5150	0.5716	0.6258	0.6901	0.7668
180	0.3543	0.3728	0.3920	0.4143	0.4388	0.4664	0.4987	0.5534	0.6059	0.6681	0.7423
185	0.3430	0.3610	0.3798	0.4014	0.4252	0.4520	0.4833	0.5363	0.5871	0.6474	0.7191
190	0.3323	0.3499	0.3682	0.3892	0.4124	0.4383	0.4687	0.5201	0.5693	0.6277	0.6972
195	0.3221	0.3393	0.3572	0.3777	0.4002	0.4254	0.4549	0.5047	0.5525	0.6091	0.6765
200	0.3125	0.3294	0.3468	0.3668	0.3887	0.4132	0.4418	0.4902	0.5365	0.5914	0.6569
205	0.3034	0.3199	0.3369	0.3564	0.3777	0.4015	0.4294	0.4764	0.5214	0.5747	0.6382
210	0.2948	0.3109	0.3275	0.3465	0.3673	0.3905	0.4176	0.4633	0.5070	0.5588	0.6205
215	0.2865	0.3024	0.3186	0.3372	0.3574	0.3800	0.4064	0.4508	0.4933	0.5437	0.6037
220	0.2787	0.2942	0.3101	0.3283	0.3480	0.3700	0.3957	0.4389	0.4803	0.5293	0.5877
225	0.2712	0.2865	0.3021	0.3198	0.3391	0.3605	0.3855	0.4277	0.4679	0.5156	0.5724
230	0.2641	0.2791	0.2944	0.3117	0.3305	0.3515	0.3758	0.4169	0.4561	0.5026	0.5579
235	0.2574	0.2721	0.2870	0.3040	0.3224	0.3428	0.3666	0.4066	0.4449	0.4902	0.5441
240	0.2509	0.2654	0.2801	0.2966	0.3146	0.3346	0.3578	0.3968	0.4342	0.4783	0.5308
245	0.2448	0.2590	0.2734	0.2896	0.3072	0.3267	0.3494	0.3875	0.4239	0.4670	0.5182
250	0.2389	0.2528	0.2670	0.2829	0.3001	0.3192	0.3413	0.3786	0.4141	0.4561	0.5062
255	0.2332	0.2470	0.2609	0.2765	0.2934	0.3120	0.3336	0.3700	0.4047	0.4458	0.4946
260	0.2278	0.2414	0.2550	0.2704	0.2869	0.3051	0.3263	0.3618	0.3958	0.4359	0.4836
265	0.2227	0.2360	0.2494	0.2645	0.2807	0.2985	0.3192	0.3540	0.3872	0.4264	0.4730
270	0.2177	0.2309	0.2441	0.2588	0.2747	0.2922	0.3125	0.3465	0.3789	0.4173	0.4629
275	0.2130	0.2260	0.2389	0.2534	0.2690	0.2862	0.3060	0.3393	0.3711	0.4086	0.4532
280	0.2085	0.2212	0.2340	0.2483	0.2636	0.2804	0.2998	0.3324	0.3635	0.4002	0.4439
285	0.2041	0.2167	0.2293	0.2433	0.2583	0.2748	0.2939	0.3258	0.3563	0.3922	0.4350
290	0.1999	0.2124	0.2248	0.2385	0.2533	0.2695	0.2882	0.3195	0.3493	0.3845	0.4264
295	0.1959	0.2082	0.2204	0.2340	0.2484	0.2643	0.2827	0.3134	0.3426	0.3771	0.4182
300	0.1921	0.2042	0.2162	0.2296	0.2438	0.2594	0.2774	0.3075	0.3362	0.3700	0.4103
305	0.1884	0.2003	0.2122	0.2253	0.2393	0.2547	0.2724	0.3019	0.3300	0.3632	0.4027
310	0.1848	0.1966	0.2083	0.2213	0.2350	0.2501	0.2675	0.2965	0.3241	0.3567	0.3954
315	0.1814	0.1931	0.2046	0.2174	0.2309	0.2457	0.2628	0.2913	0.3184	0.3504	0.3884
320	0.1781	0.1896	0.2010	0.2136	0.2269	0.2415	0.2583	0.2863	0.3129	0.3443	0.3816
325	0.1749	0.1863	0.1976	0.2100	0.2231	0.2375	0.2539	0.2814	0.3076	0.3384	0.3751
330	0.1718	0.1831	0.1943	0.2065	0.2194	0.2335	0.2498	0.2768	0.3025	0.3328	0.3688
335	0.1689	0.1801	0.1911	0.2031	0.2159	0.2298	0.2457	0.2723	0.2976	0.3274	0.3628
340	0.1660	0.1771	0.1880	0.1999	0.2124	0.2261	0.2418	0.2680	0.2928	0.3221	0.3570
345	0.1633	0.1743	0.1850	0.1968	0.2091	0.2226	0.2381	0.2638	0.2883	0.3171	0.3513
350	0.1606	0.1715	0.1821	0.1937	0.2060	0.2192	0.2345	0.2598	0.2839	0.3122	0.3459

ABSOLUTE VISCOSITY (cP) OF NaCl SOLUTIONS
PRESSURE = 6000psi

FILE NAME : VIS60

TEMP. DEG.F	SALINITY, percent by weight										
	0	2.5	5.0	7.5	10.0	12.5	15.0	17.5	20.0	22.5	25.0
150	0.4401	0.4618	0.4848	0.5117	0.5417	0.5755	0.6154	0.6831	0.7482	0.8254	0.9175
155	0.4239	0.4450	0.4673	0.4933	0.5222	0.5549	0.5934	0.6586	0.7213	0.7957	0.8843
160	0.4086	0.4291	0.4508	0.4760	0.5040	0.5355	0.5726	0.6356	0.6961	0.7678	0.8532
165	0.3943	0.4143	0.4353	0.4598	0.4868	0.5173	0.5532	0.6140	0.6723	0.7415	0.8240
170	0.3808	0.4003	0.4207	0.4444	0.4707	0.5002	0.5349	0.5936	0.6500	0.7168	0.7965
175	0.3681	0.3871	0.4070	0.4300	0.4555	0.4840	0.5176	0.5744	0.6289	0.6935	0.7706
180	0.3562	0.3747	0.3940	0.4164	0.4411	0.4688	0.5013	0.5563	0.6090	0.6716	0.7461
185	0.3448	0.3629	0.3818	0.4035	0.4275	0.4544	0.4859	0.5392	0.5903	0.6508	0.7230
190	0.3341	0.3518	0.3702	0.3914	0.4147	0.4407	0.4713	0.5230	0.5725	0.6312	0.7011
195	0.3240	0.3413	0.3592	0.3799	0.4025	0.4278	0.4575	0.5076	0.5557	0.6126	0.6804
200	0.3144	0.3313	0.3488	0.3689	0.3910	0.4156	0.4444	0.4931	0.5397	0.5949	0.6607
205	0.3053	0.3218	0.3390	0.3586	0.3800	0.4040	0.4320	0.4793	0.5246	0.5782	0.6421
210	0.2966	0.3128	0.3296	0.3487	0.3696	0.3929	0.4202	0.4662	0.5102	0.5623	0.6244
215	0.2884	0.3043	0.3207	0.3393	0.3597	0.3824	0.4090	0.4537	0.4965	0.5472	0.6076
220	0.2805	0.2962	0.3122	0.3304	0.3503	0.3725	0.3983	0.4418	0.4835	0.5328	0.5916
225	0.2731	0.2884	0.3041	0.3220	0.3414	0.3630	0.3881	0.4306	0.4711	0.5191	0.5763
230	0.2660	0.2810	0.2964	0.3139	0.3328	0.3539	0.3784	0.4198	0.4593	0.5061	0.5618
235	0.2592	0.2740	0.2891	0.3062	0.3247	0.3453	0.3692	0.4095	0.4480	0.4936	0.5479
240	0.2527	0.2673	0.2821	0.2988	0.3169	0.3370	0.3604	0.3997	0.4373	0.4818	0.5347
245	0.2466	0.2609	0.2754	0.2918	0.3095	0.3291	0.3520	0.3904	0.4270	0.4704	0.5221
250	0.2407	0.2547	0.2690	0.2850	0.3024	0.3216	0.3439	0.3814	0.4172	0.4596	0.5100
255	0.2350	0.2489	0.2629	0.2786	0.2956	0.3144	0.3362	0.3729	0.4078	0.4492	0.4984
260	0.2296	0.2433	0.2570	0.2725	0.2891	0.3075	0.3289	0.3647	0.3989	0.4393	0.4874
265	0.2245	0.2379	0.2514	0.2666	0.2829	0.3009	0.3218	0.3568	0.3903	0.4298	0.4768
270	0.2195	0.2328	0.2461	0.2609	0.2769	0.2946	0.3150	0.3493	0.3820	0.4207	0.4667
275	0.2148	0.2278	0.2409	0.2555	0.2712	0.2885	0.3086	0.3421	0.3741	0.4120	0.4570
280	0.2102	0.2231	0.2360	0.2504	0.2658	0.2827	0.3024	0.3352	0.3666	0.4036	0.4476
285	0.2059	0.2186	0.2313	0.2454	0.2605	0.2772	0.2964	0.3286	0.3593	0.3956	0.4387
290	0.2017	0.2142	0.2267	0.2406	0.2555	0.2718	0.2907	0.3222	0.3523	0.3879	0.4301
295	0.1976	0.2100	0.2224	0.2360	0.2506	0.2667	0.2852	0.3161	0.3456	0.3805	0.4219
300	0.1938	0.2060	0.2182	0.2316	0.2460	0.2617	0.2799	0.3103	0.3392	0.3734	0.4140
305	0.1901	0.2022	0.2141	0.2274	0.2415	0.2570	0.2748	0.3046	0.3330	0.3665	0.4064
310	0.1865	0.1984	0.2103	0.2233	0.2372	0.2524	0.2699	0.2992	0.3271	0.3599	0.3990
315	0.1831	0.1949	0.2065	0.2194	0.2331	0.2480	0.2652	0.2940	0.3213	0.3536	0.3920
320	0.1797	0.1914	0.2029	0.2156	0.2291	0.2438	0.2607	0.2890	0.3158	0.3475	0.3852
325	0.1766	0.1881	0.1995	0.2120	0.2252	0.2397	0.2564	0.2841	0.3105	0.3417	0.3787
330	0.1735	0.1849	0.1961	0.2085	0.2215	0.2358	0.2522	0.2795	0.3054	0.3360	0.3724
335	0.1705	0.1818	0.1929	0.2051	0.2180	0.2320	0.2481	0.2750	0.3005	0.3306	0.3663
340	0.1677	0.1789	0.1898	0.2019	0.2145	0.2284	0.2442	0.2706	0.2957	0.3253	0.3605
345	0.1649	0.1760	0.1869	0.1987	0.2112	0.2249	0.2405	0.2665	0.2912	0.3203	0.3549
350	0.1623	0.1732	0.1840	0.1957	0.2080	0.2215	0.2368	0.2624	0.2867	0.3154	0.3494

ABSOLUTE VISCOSITY(CP) OF NaCl SOLUTIONS
PRESSURE = 7000psi

FILE NAME : VIS70

TEMP. DEG.F	SALINITY, percent by weight										
	0	2.5	5.0	7.5	10.0	12.5	15.0	17.5	20.0	22.5	25.0
150	0.4419	0.4636	0.4867	0.5137	0.5438	0.5778	0.6178	0.6858	0.7511	0.8286	0.9210
155	0.4256	0.4468	0.4692	0.4953	0.5244	0.5572	0.5958	0.6613	0.7243	0.7989	0.8880
160	0.4104	0.4310	0.4527	0.4781	0.5062	0.5379	0.5751	0.6384	0.6991	0.7711	0.8569
165	0.3961	0.4162	0.4373	0.4618	0.4890	0.5197	0.5557	0.6168	0.6754	0.7449	0.8277
170	0.3826	0.4022	0.4227	0.4466	0.4729	0.5026	0.5374	0.5964	0.6531	0.7202	0.8003
175	0.3700	0.3890	0.4090	0.4321	0.4577	0.4864	0.5201	0.5772	0.6320	0.6970	0.7744
180	0.3580	0.3766	0.3961	0.4185	0.4433	0.4712	0.5038	0.5591	0.6122	0.6750	0.7499
185	0.3467	0.3649	0.3838	0.4057	0.4298	0.4568	0.4885	0.5420	0.5934	0.6543	0.7268
190	0.3360	0.3537	0.3722	0.3935	0.4169	0.4432	0.4739	0.5258	0.5756	0.6346	0.7049
195	0.3258	0.3432	0.3613	0.3820	0.4048	0.4303	0.4601	0.5105	0.5588	0.6161	0.6842
200	0.3162	0.3332	0.3509	0.3711	0.3932	0.4180	0.4470	0.4960	0.5429	0.5984	0.6646
205	0.3071	0.3238	0.3410	0.3607	0.3823	0.4064	0.4346	0.4822	0.5277	0.5817	0.6460
210	0.2984	0.3148	0.3316	0.3509	0.3719	0.3954	0.4228	0.4691	0.5134	0.5658	0.6283
215	0.2902	0.3062	0.3227	0.3415	0.3620	0.3849	0.4116	0.4566	0.4997	0.5507	0.6114
220	0.2824	0.2981	0.3142	0.3326	0.3526	0.3749	0.4009	0.4447	0.4867	0.5363	0.5954
225	0.2749	0.2904	0.3062	0.3241	0.3437	0.3654	0.3907	0.4334	0.4743	0.5226	0.5802
230	0.2678	0.2830	0.2985	0.3160	0.3351	0.3563	0.3810	0.4227	0.4625	0.5096	0.5656
235	0.2610	0.2759	0.2911	0.3083	0.3270	0.3477	0.3718	0.4124	0.4512	0.4971	0.5518
240	0.2546	0.2692	0.2841	0.3009	0.3192	0.3394	0.3630	0.4026	0.4404	0.4852	0.5385
245	0.2484	0.2628	0.2774	0.2939	0.3118	0.3315	0.3545	0.3932	0.4302	0.4739	0.5259
250	0.2425	0.2566	0.2710	0.2872	0.3047	0.3240	0.3465	0.3843	0.4203	0.4630	0.5138
255	0.2368	0.2508	0.2649	0.2807	0.2979	0.3168	0.3388	0.3757	0.4109	0.4526	0.5022
260	0.2314	0.2452	0.2590	0.2746	0.2914	0.3099	0.3314	0.3675	0.4019	0.4427	0.4912
265	0.2262	0.2398	0.2534	0.2687	0.2851	0.3033	0.3243	0.3597	0.3933	0.4332	0.4806
270	0.2213	0.2346	0.2480	0.2630	0.2792	0.2970	0.3176	0.3521	0.3851	0.4241	0.4704
275	0.2165	0.2297	0.2429	0.2576	0.2735	0.2909	0.3111	0.3449	0.3772	0.4153	0.4607
280	0.2120	0.2250	0.2379	0.2524	0.2680	0.2851	0.3049	0.3380	0.3696	0.4069	0.4514
285	0.2076	0.2204	0.2332	0.2474	0.2627	0.2795	0.2989	0.3314	0.3623	0.3989	0.4424
290	0.2034	0.2160	0.2287	0.2427	0.2577	0.2741	0.2931	0.3250	0.3553	0.3912	0.4338
295	0.1994	0.2119	0.2243	0.2381	0.2528	0.2690	0.2876	0.3189	0.3486	0.3838	0.4255
300	0.1955	0.2078	0.2201	0.2337	0.2481	0.2640	0.2823	0.3130	0.3422	0.3766	0.4176
305	0.1918	0.2040	0.2160	0.2294	0.2437	0.2593	0.2773	0.3073	0.3360	0.3698	0.4100
310	0.1882	0.2002	0.2122	0.2253	0.2393	0.2547	0.2724	0.3019	0.3300	0.3632	0.4026
315	0.1847	0.1966	0.2084	0.2214	0.2352	0.2503	0.2677	0.2967	0.3243	0.3568	0.3956
320	0.1814	0.1932	0.2048	0.2176	0.2312	0.2460	0.2631	0.2916	0.3187	0.3507	0.3888
325	0.1782	0.1899	0.2013	0.2140	0.2273	0.2420	0.2588	0.2868	0.3134	0.3449	0.3822
330	0.1751	0.1867	0.1980	0.2105	0.2236	0.2380	0.2546	0.2821	0.3083	0.3392	0.3759
335	0.1722	0.1836	0.1948	0.2071	0.2201	0.2342	0.2505	0.2776	0.3034	0.3337	0.3699
340	0.1693	0.1806	0.1917	0.2038	0.2166	0.2306	0.2466	0.2733	0.2986	0.3285	0.3640
345	0.1665	0.1777	0.1887	0.2007	0.2133	0.2271	0.2428	0.2691	0.2940	0.3234	0.3583
350	0.1639	0.1750	0.1858	0.1976	0.2101	0.2237	0.2392	0.2650	0.2896	0.3185	0.3529

ABSOLUTE VISCOSITY(cp) OF NaCl SOLUTIONS

PRESSURE = 8000psi

FILE NAME : VIS80

TEMP. DEG.F	SALINITY, Percent by weight										
	0	2.5	5.0	7.5	10.0	12.5	15.0	17.5	20.0	22.5	25.0
150	0.4436	0.4654	0.4886	0.5158	0.5460	0.5801	0.6203	0.6885	0.7541	0.8319	0.9247
155	0.4274	0.4486	0.4711	0.4974	0.5266	0.5595	0.5983	0.6641	0.7273	0.8023	0.8916
160	0.4122	0.4329	0.4547	0.4802	0.5084	0.5402	0.5776	0.6411	0.7021	0.7744	0.8607
165	0.3979	0.4181	0.4393	0.4639	0.4913	0.5220	0.5582	0.6196	0.6784	0.7483	0.8315
170	0.3845	0.4041	0.4247	0.4487	0.4752	0.5049	0.5399	0.5992	0.6562	0.7236	0.8041
175	0.3718	0.3909	0.4110	0.4343	0.4600	0.4888	0.5227	0.5801	0.6351	0.7004	0.7782
180	0.3598	0.3785	0.3981	0.4207	0.4456	0.4736	0.5064	0.5620	0.6153	0.6785	0.7538
185	0.3485	0.3668	0.3859	0.4078	0.4321	0.4592	0.4910	0.5449	0.5965	0.6577	0.7307
190	0.3378	0.3557	0.3743	0.3957	0.4192	0.4456	0.4765	0.5287	0.5788	0.6381	0.7088
195	0.3277	0.3452	0.3633	0.3842	0.4071	0.4327	0.4627	0.5134	0.5620	0.6195	0.6881
200	0.3181	0.3352	0.3529	0.3733	0.3955	0.4205	0.4496	0.4989	0.5460	0.6019	0.6685
205	0.3089	0.3257	0.3431	0.3629	0.3846	0.4089	0.4372	0.4851	0.5309	0.5852	0.6499
210	0.3003	0.3167	0.3337	0.3530	0.3742	0.3978	0.4254	0.4720	0.5165	0.5693	0.6322
215	0.2920	0.3082	0.3248	0.3437	0.3643	0.3873	0.4142	0.4595	0.5028	0.5542	0.6153
220	0.2842	0.3000	0.3163	0.3348	0.3549	0.3773	0.4035	0.4476	0.4898	0.5398	0.5993
225	0.2767	0.2923	0.3082	0.3263	0.3459	0.3678	0.3933	0.4363	0.4774	0.5261	0.5840
230	0.2696	0.2849	0.3005	0.3182	0.3374	0.3588	0.3836	0.4255	0.4656	0.5130	0.5695
235	0.2628	0.2778	0.2931	0.3105	0.3292	0.3501	0.3744	0.4153	0.4543	0.5006	0.5556
240	0.2564	0.2711	0.2861	0.3031	0.3215	0.3418	0.3656	0.4054	0.4436	0.4887	0.5424
245	0.2502	0.2647	0.2794	0.2960	0.3140	0.3339	0.3571	0.3961	0.4333	0.4773	0.5297
250	0.2443	0.2585	0.2730	0.2893	0.3069	0.3264	0.3490	0.3871	0.4234	0.4664	0.5176
255	0.2386	0.2527	0.2669	0.2829	0.3001	0.3192	0.3413	0.3785	0.4140	0.4560	0.5060
260	0.2332	0.2470	0.2610	0.2767	0.2936	0.3123	0.3339	0.3703	0.4050	0.4461	0.4949
265	0.2280	0.2417	0.2554	0.2708	0.2874	0.3057	0.3269	0.3625	0.3964	0.4365	0.4843
270	0.2230	0.2365	0.2500	0.2651	0.2814	0.2993	0.3201	0.3549	0.3881	0.4274	0.4741
275	0.2183	0.2315	0.2448	0.2597	0.2757	0.2932	0.3136	0.3477	0.3802	0.4187	0.4644
280	0.2137	0.2268	0.2399	0.2545	0.2702	0.2874	0.3073	0.3408	0.3726	0.4103	0.4550
285	0.2093	0.2222	0.2351	0.2495	0.2649	0.2818	0.3014	0.3341	0.3653	0.4022	0.4461
290	0.2051	0.2179	0.2306	0.2447	0.2598	0.2764	0.2956	0.3277	0.3583	0.3945	0.4375
295	0.2011	0.2137	0.2262	0.2401	0.2550	0.2713	0.2901	0.3216	0.3516	0.3870	0.4292
300	0.1972	0.2096	0.2220	0.2357	0.2503	0.2663	0.2848	0.3157	0.3451	0.3799	0.4212
305	0.1934	0.2057	0.2179	0.2314	0.2458	0.2615	0.2797	0.3100	0.3389	0.3730	0.4136
310	0.1898	0.2020	0.2140	0.2273	0.2415	0.2569	0.2748	0.3046	0.3329	0.3664	0.4062
315	0.1864	0.1984	0.2103	0.2234	0.2373	0.2525	0.2701	0.2993	0.3272	0.3601	0.3991
320	0.1831	0.1949	0.2067	0.2196	0.2333	0.2483	0.2655	0.2943	0.3216	0.3539	0.3923
325	0.1798	0.1916	0.2032	0.2159	0.2294	0.2442	0.2611	0.2894	0.3163	0.3480	0.3858
330	0.1768	0.1884	0.1998	0.2124	0.2257	0.2402	0.2569	0.2847	0.3112	0.3424	0.3794
335	0.1738	0.1853	0.1966	0.2090	0.2221	0.2364	0.2529	0.2802	0.3062	0.3369	0.3733
340	0.1709	0.1823	0.1935	0.2058	0.2187	0.2328	0.2489	0.2759	0.3014	0.3316	0.3675
345	0.1681	0.1794	0.1905	0.2026	0.2154	0.2292	0.2452	0.2717	0.2968	0.3265	0.3618
350	0.1655	0.1767	0.1876	0.1996	0.2121	0.2258	0.2415	0.2676	0.2924	0.3216	0.3563

ABSOLUTE VISCOSITY(CP) OF NaCl SOLUTIONS
PRESSURE = 9000psi

FILE NAME : VIS90

TEMP. DEG.F	SALINITY, percent by weight										
	0	2.5	5.0	7.5	10.0	12.5	15.0	17.5	20.0	22.5	25.0
150	0.4454	0.4673	0.4906	0.5178	0.5481	0.5824	0.6227	0.6912	0.7571	0.8352	0.9283
155	0.4292	0.4505	0.4731	0.4995	0.5288	0.5618	0.6008	0.6669	0.7303	0.8056	0.8954
160	0.4140	0.4348	0.4567	0.4823	0.5106	0.5426	0.5802	0.6439	0.7052	0.7778	0.8644
165	0.3997	0.4200	0.4413	0.4661	0.4935	0.5244	0.5608	0.6224	0.6815	0.7517	0.8353
170	0.3863	0.4060	0.4268	0.4508	0.4774	0.5073	0.5425	0.6021	0.6593	0.7271	0.8079
175	0.3736	0.3929	0.4131	0.4364	0.4622	0.4912	0.5253	0.5830	0.6383	0.7039	0.7820
180	0.3617	0.3805	0.4001	0.4228	0.4479	0.4760	0.5090	0.5649	0.6184	0.6819	0.7576
185	0.3504	0.3687	0.3879	0.4100	0.4343	0.4616	0.4936	0.5478	0.5997	0.6612	0.7345
190	0.3397	0.3576	0.3763	0.3979	0.4215	0.4480	0.4791	0.5316	0.5820	0.6416	0.7127
195	0.3295	0.3471	0.3654	0.3863	0.4094	0.4351	0.4653	0.5163	0.5652	0.6230	0.6920
200	0.3199	0.3371	0.3550	0.3754	0.3978	0.4229	0.4522	0.5018	0.5492	0.6054	0.6724
205	0.3108	0.3277	0.3451	0.3651	0.3869	0.4113	0.4398	0.4880	0.5341	0.5887	0.6537
210	0.3021	0.3187	0.3357	0.3552	0.3765	0.4003	0.4280	0.4749	0.5197	0.5728	0.6360
215	0.2939	0.3101	0.3268	0.3458	0.3666	0.3898	0.4168	0.4624	0.5060	0.5577	0.6192
220	0.2860	0.3020	0.3183	0.3369	0.3572	0.3798	0.4061	0.4505	0.4930	0.5433	0.6032
225	0.2786	0.2942	0.3102	0.3284	0.3482	0.3703	0.3959	0.4392	0.4806	0.5296	0.5879
230	0.2715	0.2868	0.3025	0.3203	0.3397	0.3612	0.3862	0.4284	0.4688	0.5165	0.5733
235	0.2647	0.2798	0.2952	0.3126	0.3315	0.3525	0.3770	0.4181	0.4575	0.5040	0.5594
240	0.2582	0.2730	0.2881	0.3052	0.3237	0.3442	0.3681	0.4083	0.4467	0.4921	0.5462
245	0.2520	0.2666	0.2814	0.2982	0.3163	0.3363	0.3597	0.3989	0.4364	0.4807	0.5335
250	0.2460	0.2604	0.2750	0.2914	0.3091	0.3288	0.3516	0.3899	0.4265	0.4698	0.5214
255	0.2404	0.2545	0.2689	0.2850	0.3023	0.3216	0.3439	0.3813	0.4171	0.4594	0.5098
260	0.2350	0.2489	0.2630	0.2788	0.2958	0.3146	0.3365	0.3731	0.4081	0.4495	0.4987
265	0.2298	0.2435	0.2574	0.2729	0.2896	0.3080	0.3294	0.3652	0.3995	0.4399	0.4880
270	0.2248	0.2383	0.2520	0.2672	0.2836	0.3017	0.3226	0.3577	0.3912	0.4308	0.4779
275	0.2200	0.2334	0.2468	0.2618	0.2778	0.2956	0.3161	0.3505	0.3832	0.4220	0.4681
280	0.2154	0.2286	0.2418	0.2565	0.2723	0.2897	0.3098	0.3435	0.3756	0.4136	0.4587
285	0.2110	0.2241	0.2371	0.2515	0.2671	0.2841	0.3038	0.3369	0.3683	0.4055	0.4497
290	0.2068	0.2197	0.2325	0.2467	0.2620	0.2787	0.2981	0.3305	0.3613	0.3977	0.4411
295	0.2028	0.2155	0.2281	0.2421	0.2571	0.2735	0.2925	0.3243	0.3546	0.3903	0.4328
300	0.1989	0.2114	0.2239	0.2377	0.2524	0.2686	0.2872	0.3184	0.3481	0.3831	0.4248
305	0.1951	0.2075	0.2198	0.2334	0.2479	0.2638	0.2821	0.3127	0.3418	0.3762	0.4171
310	0.1915	0.2038	0.2159	0.2293	0.2436	0.2592	0.2772	0.3072	0.3358	0.3696	0.4098
315	0.1880	0.2002	0.2121	0.2254	0.2394	0.2548	0.2725	0.3020	0.3301	0.3632	0.4027
320	0.1847	0.1967	0.2085	0.2216	0.2354	0.2505	0.2679	0.2969	0.3245	0.3571	0.3958
325	0.1815	0.1933	0.2050	0.2179	0.2315	0.2464	0.2635	0.2920	0.3192	0.3512	0.3892
330	0.1784	0.1901	0.2017	0.2144	0.2278	0.2424	0.2593	0.2873	0.3140	0.3455	0.3829
335	0.1754	0.1870	0.1984	0.2110	0.2242	0.2386	0.2552	0.2828	0.3090	0.3400	0.3768
340	0.1725	0.1840	0.1953	0.2077	0.2207	0.2349	0.2513	0.2784	0.3043	0.3347	0.3709
345	0.1697	0.1811	0.1923	0.2045	0.2174	0.2314	0.2475	0.2742	0.2996	0.3296	0.3652
350	0.1670	0.1783	0.1894	0.2015	0.2142	0.2280	0.2438	0.2702	0.2952	0.3247	0.3597

ABSOLUTE VISCOSITY (CP) OF NaCl SOLUTIONS
PRESSURE = 10000Psi

FILE NAME : VIS100

TEMP. DEG.F	SALINITY, percent by weight										
	0	2.5	5.0	7.5	10.0	12.5	15.0	17.5	20.0	22.5	25.0
150	0.4471	0.4692	0.4925	0.5199	0.5503	0.5847	0.6252	0.6940	0.7601	0.8386	0.9321
155	0.4310	0.4524	0.4751	0.5016	0.5310	0.5642	0.6033	0.6697	0.7334	0.8090	0.8991
160	0.4158	0.4367	0.4587	0.4844	0.5128	0.5450	0.5827	0.6468	0.7083	0.7812	0.8682
165	0.4016	0.4219	0.4433	0.4682	0.4958	0.5268	0.5633	0.6252	0.6847	0.7551	0.8391
170	0.3881	0.4080	0.4288	0.4530	0.4797	0.5098	0.5451	0.6050	0.6624	0.7305	0.8117
175	0.3755	0.3948	0.4151	0.4386	0.4645	0.4937	0.5279	0.5858	0.6414	0.7073	0.7859
180	0.3635	0.3824	0.4022	0.4250	0.4502	0.4785	0.5116	0.5678	0.6216	0.6854	0.7615
185	0.3522	0.3707	0.3900	0.4122	0.4366	0.4641	0.4963	0.5507	0.6029	0.6647	0.7384
190	0.3415	0.3596	0.3784	0.4000	0.4238	0.4505	0.4817	0.5345	0.5851	0.6451	0.7166
195	0.3314	0.3491	0.3674	0.3885	0.4117	0.4376	0.4679	0.5192	0.5683	0.6265	0.6959
200	0.3218	0.3391	0.3570	0.3776	0.4002	0.4254	0.4549	0.5047	0.5524	0.6089	0.6763
205	0.3126	0.3296	0.3472	0.3672	0.3892	0.4138	0.4424	0.4909	0.5373	0.5922	0.6576
210	0.3040	0.3206	0.3378	0.3574	0.3788	0.4027	0.4306	0.4778	0.5229	0.5763	0.6399
215	0.2957	0.3121	0.3289	0.3480	0.3689	0.3922	0.4194	0.4653	0.5092	0.5612	0.6231
220	0.2879	0.3039	0.3204	0.3391	0.3595	0.3822	0.4087	0.4534	0.4962	0.5468	0.6070
225	0.2804	0.2961	0.3123	0.3306	0.3505	0.3727	0.3985	0.4421	0.4837	0.5330	0.5917
230	0.2733	0.2887	0.3045	0.3225	0.3419	0.3636	0.3888	0.4313	0.4719	0.5200	0.5772
235	0.2665	0.2817	0.2972	0.3147	0.3338	0.3549	0.3795	0.4210	0.4606	0.5075	0.5633
240	0.2600	0.2749	0.2901	0.3073	0.3260	0.3466	0.3707	0.4112	0.4498	0.4955	0.5500
245	0.2538	0.2685	0.2834	0.3003	0.3185	0.3387	0.3622	0.4017	0.4395	0.4841	0.5373
250	0.2478	0.2623	0.2770	0.2935	0.3114	0.3312	0.3541	0.3928	0.4296	0.4732	0.5252
255	0.2422	0.2564	0.2708	0.2871	0.3046	0.3239	0.3464	0.3842	0.4202	0.4628	0.5135
260	0.2367	0.2508	0.2650	0.2809	0.2980	0.3170	0.3390	0.3759	0.4112	0.4528	0.5024
265	0.2315	0.2454	0.2593	0.2749	0.2918	0.3104	0.3319	0.3680	0.4025	0.4433	0.4918
270	0.2265	0.2402	0.2539	0.2693	0.2858	0.3040	0.3251	0.3605	0.3942	0.4341	0.4816
275	0.2217	0.2352	0.2487	0.2638	0.2800	0.2979	0.3186	0.3532	0.3863	0.4253	0.4718
280	0.2171	0.2304	0.2438	0.2586	0.2745	0.2920	0.3123	0.3463	0.3786	0.4169	0.4624
285	0.2127	0.2259	0.2390	0.2536	0.2692	0.2864	0.3063	0.3396	0.3713	0.4088	0.4534
290	0.2085	0.2215	0.2344	0.2488	0.2641	0.2810	0.3005	0.3332	0.3643	0.4010	0.4447
295	0.2044	0.2172	0.2300	0.2441	0.2592	0.2758	0.2950	0.3270	0.3575	0.3935	0.4364
300	0.2005	0.2132	0.2258	0.2397	0.2545	0.2708	0.2896	0.3211	0.3510	0.3863	0.4284
305	0.1968	0.2093	0.2217	0.2354	0.2500	0.2660	0.2845	0.3154	0.3447	0.3794	0.4207
310	0.1932	0.2055	0.2178	0.2313	0.2457	0.2614	0.2796	0.3099	0.3387	0.3728	0.4133
315	0.1897	0.2019	0.2140	0.2273	0.2415	0.2570	0.2748	0.3046	0.3329	0.3664	0.4062
320	0.1863	0.1984	0.2104	0.2235	0.2375	0.2527	0.2703	0.2995	0.3274	0.3602	0.3993
325	0.1831	0.1951	0.2069	0.2198	0.2336	0.2486	0.2659	0.2946	0.3220	0.3543	0.3927
330	0.1800	0.1918	0.2035	0.2163	0.2298	0.2446	0.2616	0.2899	0.3168	0.3486	0.3863
335	0.1770	0.1887	0.2002	0.2129	0.2262	0.2408	0.2575	0.2854	0.3119	0.3431	0.3802
340	0.1741	0.1857	0.1971	0.2096	0.2228	0.2371	0.2536	0.2810	0.3071	0.3378	0.3743
345	0.1713	0.1828	0.1941	0.2064	0.2194	0.2336	0.2498	0.2768	0.3024	0.3327	0.3686
350	0.1686	0.1800	0.1912	0.2033	0.2162	0.2301	0.2461	0.2727	0.2979	0.3277	0.3631

ABSOLUTE VISCOSITY(cp) OF NaCl SOLUTIONS

PRESSURE = 11000psi

FILE NAME : VIS110

TEMP. DEG.F	SALINITY, percent by weight										
	0	2.5	5.0	7.5	10.0	12.5	15.0	17.5	20.0	22.5	25.0
150	0.4490	0.4711	0.4945	0.5220	0.5526	0.5871	0.6278	0.6968	0.7632	0.8420	0.9359
155	0.4328	0.4543	0.4771	0.5037	0.5333	0.5666	0.6059	0.6725	0.7365	0.8124	0.9030
160	0.4177	0.4386	0.4607	0.4865	0.5151	0.5474	0.5853	0.6496	0.7114	0.7847	0.8721
165	0.4034	0.4238	0.4453	0.4704	0.4981	0.5293	0.5659	0.6281	0.6878	0.7586	0.8430
170	0.3900	0.4099	0.4308	0.4551	0.4820	0.5122	0.5477	0.6079	0.6656	0.7340	0.8156
175	0.3773	0.3968	0.4172	0.4408	0.4668	0.4961	0.5305	0.5887	0.6446	0.7109	0.7898
180	0.3654	0.3844	0.4042	0.4272	0.4525	0.4809	0.5143	0.5707	0.6248	0.6890	0.7654
185	0.3541	0.3726	0.3920	0.4144	0.4390	0.4666	0.4989	0.5536	0.6061	0.6682	0.7423
190	0.3434	0.3615	0.3805	0.4022	0.4261	0.4529	0.4843	0.5374	0.5883	0.6486	0.7205
195	0.3332	0.3510	0.3695	0.3907	0.4140	0.4401	0.4706	0.5221	0.5715	0.6301	0.6998
200	0.3236	0.3411	0.3591	0.3798	0.4025	0.4278	0.4575	0.5076	0.5556	0.6124	0.6802
205	0.3145	0.3316	0.3492	0.3694	0.3915	0.4162	0.4451	0.4938	0.5404	0.5957	0.6615
210	0.3058	0.3226	0.3398	0.3596	0.3811	0.4052	0.4333	0.4807	0.5260	0.5798	0.6438
215	0.2976	0.3140	0.3309	0.3502	0.3712	0.3947	0.4220	0.4682	0.5124	0.5647	0.6270
220	0.2897	0.3059	0.3224	0.3412	0.3618	0.3846	0.4113	0.4563	0.4993	0.5502	0.6109
225	0.2822	0.2981	0.3143	0.3327	0.3528	0.3751	0.4011	0.4450	0.4869	0.5365	0.5956
230	0.2751	0.2907	0.3066	0.3246	0.3442	0.3660	0.3914	0.4342	0.4750	0.5234	0.5810
235	0.2683	0.2836	0.2992	0.3169	0.3360	0.3573	0.3821	0.4238	0.4637	0.5109	0.5671
240	0.2618	0.2768	0.2922	0.3095	0.3282	0.3490	0.3733	0.4140	0.4529	0.4990	0.5538
245	0.2556	0.2704	0.2854	0.3024	0.3208	0.3411	0.3648	0.4046	0.4426	0.4876	0.5411
250	0.2496	0.2642	0.2790	0.2956	0.3136	0.3335	0.3567	0.3956	0.4327	0.4766	0.5289
255	0.2439	0.2583	0.2728	0.2892	0.3068	0.3263	0.3489	0.3870	0.4233	0.4662	0.5173
260	0.2385	0.2526	0.2669	0.2830	0.3002	0.3193	0.3415	0.3787	0.4142	0.4562	0.5061
265	0.2333	0.2472	0.2613	0.2770	0.2940	0.3127	0.3344	0.3708	0.4055	0.4466	0.4955
270	0.2283	0.2420	0.2559	0.2713	0.2880	0.3063	0.3276	0.3632	0.3972	0.4374	0.4852
275	0.2235	0.2370	0.2507	0.2659	0.2822	0.3002	0.3210	0.3560	0.3893	0.4286	0.4754
280	0.2189	0.2323	0.2457	0.2606	0.2767	0.2943	0.3148	0.3490	0.3816	0.4202	0.4660
285	0.2144	0.2277	0.2409	0.2556	0.2714	0.2887	0.3087	0.3423	0.3743	0.4120	0.4570
290	0.2102	0.2233	0.2363	0.2508	0.2663	0.2833	0.3029	0.3359	0.3672	0.4042	0.4483
295	0.2061	0.2190	0.2319	0.2461	0.2614	0.2781	0.2974	0.3297	0.3604	0.3968	0.4400
300	0.2022	0.2150	0.2276	0.2417	0.2566	0.2731	0.2920	0.3237	0.3539	0.3896	0.4319
305	0.1984	0.2110	0.2235	0.2374	0.2521	0.2683	0.2869	0.3180	0.3476	0.3826	0.4242
310	0.1948	0.2073	0.2196	0.2332	0.2478	0.2636	0.2819	0.3125	0.3416	0.3760	0.4168
315	0.1913	0.2036	0.2158	0.2293	0.2436	0.2592	0.2772	0.3072	0.3358	0.3695	0.4097
320	0.1879	0.2001	0.2122	0.2254	0.2395	0.2549	0.2726	0.3021	0.3302	0.3634	0.4028
325	0.1847	0.1968	0.2087	0.2218	0.2356	0.2508	0.2682	0.2972	0.3248	0.3574	0.3962
330	0.1816	0.1935	0.2053	0.2182	0.2319	0.2468	0.2639	0.2925	0.3197	0.3517	0.3898
335	0.1786	0.1904	0.2020	0.2148	0.2283	0.2430	0.2598	0.2879	0.3147	0.3462	0.3836
340	0.1757	0.1874	0.1989	0.2115	0.2248	0.2393	0.2559	0.2835	0.3098	0.3408	0.3777
345	0.1729	0.1845	0.1959	0.2083	0.2214	0.2357	0.2521	0.2793	0.3052	0.3357	0.3720
350	0.1702	0.1817	0.1929	0.2052	0.2182	0.2322	0.2484	0.2752	0.3007	0.3307	0.3664

ABSOLUTE VISCOSITY (CP) OF NaCl SOLUTIONS
PRESSURE = 12000psi

FILE NAME : V1S120

TEMP. DEG.F	SALINITY, percent by weight										
	0	2.5	5.0	7.5	10.0	12.5	15.0	17.5	20.0	22.5	25.0
150	0.4508	0.4730	0.4966	0.5241	0.5548	0.5895	0.6303	0.6997	0.7663	0.8454	0.9397
155	0.4347	0.4563	0.4791	0.5059	0.5355	0.5690	0.6085	0.6754	0.7397	0.8159	0.9068
160	0.4195	0.4406	0.4628	0.4887	0.5174	0.5498	0.5879	0.6525	0.7146	0.7882	0.8759
165	0.4053	0.4258	0.4474	0.4725	0.5004	0.5317	0.5686	0.6310	0.6910	0.7621	0.8469
170	0.3919	0.4119	0.4329	0.4573	0.4843	0.5147	0.5503	0.6108	0.6688	0.7376	0.8195
175	0.3792	0.3987	0.4192	0.4429	0.4691	0.4986	0.5331	0.5917	0.6478	0.7144	0.7937
180	0.3672	0.3863	0.4063	0.4294	0.4548	0.4834	0.5169	0.5736	0.6280	0.6925	0.7693
185	0.3559	0.3746	0.3941	0.4166	0.4413	0.4690	0.5015	0.5565	0.6093	0.6718	0.7463
190	0.3452	0.3635	0.3825	0.4044	0.4285	0.4554	0.4870	0.5404	0.5915	0.6522	0.7244
195	0.3351	0.3530	0.3716	0.3929	0.4163	0.4425	0.4732	0.5251	0.5747	0.6336	0.7037
200	0.3255	0.3430	0.3612	0.3820	0.4048	0.4303	0.4601	0.5105	0.5588	0.6160	0.6841
205	0.3164	0.3335	0.3513	0.3716	0.3938	0.4187	0.4477	0.4967	0.5436	0.5992	0.6654
210	0.3077	0.3245	0.3419	0.3617	0.3834	0.4076	0.4359	0.4836	0.5292	0.5833	0.6477
215	0.2994	0.3160	0.3330	0.3523	0.3735	0.3971	0.4246	0.4711	0.5155	0.5682	0.6308
220	0.2916	0.3078	0.3244	0.3434	0.3641	0.3871	0.4139	0.4592	0.5025	0.5537	0.6148
225	0.2841	0.3000	0.3163	0.3349	0.3551	0.3775	0.4037	0.4478	0.4900	0.5400	0.5995
230	0.2769	0.2926	0.3086	0.3268	0.3465	0.3684	0.3940	0.4370	0.4782	0.5269	0.5849
235	0.2701	0.2855	0.3012	0.3190	0.3383	0.3598	0.3847	0.4267	0.4669	0.5144	0.5709
240	0.2636	0.2787	0.2942	0.3116	0.3305	0.3514	0.3758	0.4168	0.4560	0.5024	0.5576
245	0.2573	0.2723	0.2874	0.3045	0.3230	0.3435	0.3673	0.4074	0.4457	0.4910	0.5449
250	0.2514	0.2661	0.2810	0.2977	0.3159	0.3359	0.3592	0.3984	0.4358	0.4800	0.5327
255	0.2457	0.2602	0.2748	0.2913	0.3090	0.3287	0.3515	0.3898	0.4263	0.4696	0.5210
260	0.2402	0.2545	0.2689	0.2850	0.3025	0.3217	0.3440	0.3815	0.4173	0.4595	0.5099
265	0.2350	0.2491	0.2632	0.2791	0.2962	0.3150	0.3369	0.3736	0.4086	0.4499	0.4992
270	0.2300	0.2439	0.2578	0.2734	0.2902	0.3086	0.3301	0.3660	0.4002	0.4407	0.4889
275	0.2252	0.2389	0.2526	0.2679	0.2844	0.3025	0.3235	0.3587	0.3922	0.4319	0.4791
280	0.2206	0.2341	0.2476	0.2627	0.2788	0.2966	0.3172	0.3517	0.3846	0.4234	0.4697
285	0.2161	0.2295	0.2428	0.2576	0.2735	0.2910	0.3112	0.3450	0.3772	0.4153	0.4606
290	0.2119	0.2250	0.2382	0.2528	0.2684	0.2855	0.3054	0.3385	0.3701	0.4075	0.4519
295	0.2078	0.2208	0.2338	0.2481	0.2635	0.2803	0.2998	0.3323	0.3633	0.4000	0.4435
300	0.2038	0.2167	0.2295	0.2436	0.2588	0.2753	0.2944	0.3264	0.3568	0.3927	0.4355
305	0.2001	0.2128	0.2254	0.2393	0.2542	0.2705	0.2893	0.3207	0.3505	0.3858	0.4277
310	0.1964	0.2090	0.2215	0.2352	0.2498	0.2659	0.2843	0.3151	0.3445	0.3791	0.4203
315	0.1929	0.2054	0.2177	0.2312	0.2456	0.2614	0.2795	0.3098	0.3387	0.3727	0.4131
320	0.1895	0.2019	0.2140	0.2274	0.2416	0.2571	0.2749	0.3047	0.3331	0.3665	0.4062
325	0.1863	0.1985	0.2105	0.2237	0.2377	0.2529	0.2705	0.2998	0.3277	0.3605	0.3996
330	0.1832	0.1952	0.2071	0.2201	0.2339	0.2489	0.2662	0.2951	0.3224	0.3548	0.3932
335	0.1801	0.1921	0.2038	0.2167	0.2303	0.2451	0.2621	0.2905	0.3174	0.3492	0.3870
340	0.1772	0.1891	0.2007	0.2134	0.2268	0.2414	0.2582	0.2861	0.3126	0.3439	0.3810
345	0.1744	0.1861	0.1976	0.2102	0.2234	0.2378	0.2543	0.2818	0.3079	0.3387	0.3753
350	0.1717	0.1833	0.1947	0.2071	0.2201	0.2343	0.2506	0.2777	0.3034	0.3337	0.3698

ABSOLUTE VISCOSITY(cP) OF NaCl SOLUTIONS
PRESSURE = 13000psi

FILE NAME : VIS130

TEMP. DEG.F	SALINITY, percent by weight										
	0	2.5	5.0	7.5	10.0	12.5	15.0	17.5	20.0	22.5	25.0
150	0.4527	0.4749	0.4986	0.5263	0.5571	0.5919	0.6329	0.7026	0.7695	0.8489	0.9436
155	0.4365	0.4582	0.4812	0.5080	0.5378	0.5715	0.6111	0.6783	0.7428	0.8194	0.9107
160	0.4214	0.4425	0.4649	0.4909	0.5197	0.5523	0.5905	0.6554	0.7178	0.7917	0.8799
165	0.4072	0.4278	0.4495	0.4747	0.5027	0.5342	0.5712	0.6340	0.6942	0.7657	0.8508
170	0.3937	0.4139	0.4350	0.4595	0.4866	0.5171	0.5530	0.6137	0.6720	0.7411	0.8235
175	0.3811	0.4007	0.4213	0.4451	0.4715	0.5011	0.5358	0.5946	0.6510	0.7179	0.7977
180	0.3691	0.3883	0.4084	0.4316	0.4572	0.4859	0.5195	0.5766	0.6312	0.6960	0.7733
185	0.3578	0.3766	0.3962	0.4188	0.4436	0.4715	0.5042	0.5595	0.6125	0.6753	0.7502
190	0.3471	0.3655	0.3846	0.4066	0.4308	0.4579	0.4896	0.5433	0.5948	0.6557	0.7284
195	0.3370	0.3550	0.3736	0.3951	0.4186	0.4450	0.4758	0.5280	0.5780	0.6371	0.7077
200	0.3274	0.3450	0.3632	0.3842	0.4071	0.4328	0.4628	0.5134	0.5620	0.6195	0.6880
205	0.3182	0.3355	0.3534	0.3738	0.3961	0.4211	0.4503	0.4996	0.5468	0.6028	0.6694
210	0.3095	0.3265	0.3440	0.3639	0.3857	0.4101	0.4385	0.4865	0.5324	0.5868	0.6516
215	0.3013	0.3179	0.3350	0.3545	0.3758	0.3996	0.4273	0.4740	0.5187	0.5717	0.6347
220	0.2934	0.3097	0.3265	0.3456	0.3664	0.3895	0.4165	0.4621	0.5057	0.5572	0.6187
225	0.2859	0.3019	0.3184	0.3370	0.3574	0.3800	0.4063	0.4507	0.4932	0.5435	0.6033
230	0.2787	0.2945	0.3106	0.3289	0.3488	0.3709	0.3966	0.4399	0.4813	0.5303	0.5887
235	0.2719	0.2874	0.3032	0.3211	0.3406	0.3622	0.3873	0.4296	0.4700	0.5178	0.5747
240	0.2654	0.2806	0.2962	0.3137	0.3327	0.3538	0.3784	0.4197	0.4591	0.5058	0.5614
245	0.2591	0.2742	0.2894	0.3066	0.3253	0.3459	0.3699	0.4102	0.4488	0.4944	0.5487
250	0.2532	0.2680	0.2830	0.2998	0.3181	0.3383	0.3618	0.4012	0.4389	0.4834	0.5365
255	0.2475	0.2620	0.2768	0.2933	0.3112	0.3310	0.3540	0.3926	0.4294	0.4729	0.5248
260	0.2420	0.2564	0.2709	0.2871	0.3047	0.3240	0.3465	0.3843	0.4203	0.4629	0.5136
265	0.2367	0.2509	0.2652	0.2812	0.2984	0.3174	0.3394	0.3763	0.4116	0.4533	0.5029
270	0.2317	0.2457	0.2597	0.2754	0.2923	0.3110	0.3325	0.3687	0.4032	0.4441	0.4926
275	0.2269	0.2407	0.2545	0.2700	0.2865	0.3048	0.3260	0.3614	0.3952	0.4352	0.4827
280	0.2223	0.2359	0.2495	0.2647	0.2810	0.2989	0.3197	0.3544	0.3876	0.4267	0.4733
285	0.2178	0.2313	0.2447	0.2596	0.2756	0.2933	0.3136	0.3477	0.3802	0.4185	0.4642
290	0.2136	0.2268	0.2401	0.2548	0.2705	0.2878	0.3078	0.3412	0.3731	0.4107	0.4555
295	0.2094	0.2226	0.2356	0.2501	0.2656	0.2826	0.3022	0.3350	0.3663	0.4032	0.4471
300	0.2055	0.2185	0.2314	0.2456	0.2609	0.2775	0.2968	0.3290	0.3597	0.3959	0.4390
305	0.2017	0.2145	0.2272	0.2413	0.2563	0.2727	0.2916	0.3233	0.3534	0.3890	0.4313
310	0.1981	0.2107	0.2233	0.2372	0.2519	0.2681	0.2867	0.3178	0.3473	0.3823	0.4238
315	0.1945	0.2071	0.2195	0.2332	0.2477	0.2636	0.2819	0.3124	0.3415	0.3758	0.4166
320	0.1912	0.2036	0.2158	0.2293	0.2436	0.2593	0.2773	0.3073	0.3359	0.3696	0.4097
325	0.1879	0.2002	0.2123	0.2256	0.2397	0.2551	0.2728	0.3024	0.3305	0.3636	0.4030
330	0.1847	0.1969	0.2089	0.2220	0.2359	0.2511	0.2685	0.2976	0.3252	0.3578	0.3966
335	0.1817	0.1938	0.2056	0.2186	0.2323	0.2472	0.2644	0.2930	0.3202	0.3523	0.3904
340	0.1788	0.1907	0.2024	0.2152	0.2288	0.2435	0.2604	0.2886	0.3153	0.3469	0.3844
345	0.1760	0.1878	0.1994	0.2120	0.2254	0.2399	0.2566	0.2843	0.3107	0.3417	0.3786
350	0.1732	0.1850	0.1964	0.2089	0.2221	0.2364	0.2529	0.2802	0.3061	0.3367	0.3731

ABSOLUTE VISCOSITY (CP) OF NaCl SOLUTIONS
PRESSURE = 14000psi

FILE NAME : VIS140

TEMP. DEG.F	SALINITY, percent by weight										
	0	2.5	5.0	7.5	10.0	12.5	15.0	17.5	20.0	22.5	25.0
150	0.4546	0.4769	0.5007	0.5285	0.5594	0.5944	0.6356	0.7055	0.7727	0.8524	0.9475
155	0.4384	0.4602	0.4833	0.5102	0.5402	0.5740	0.6137	0.6812	0.7461	0.8230	0.9147
160	0.4233	0.4445	0.4670	0.4931	0.5221	0.5548	0.5932	0.6584	0.7210	0.7953	0.8838
165	0.4091	0.4298	0.4516	0.4769	0.5050	0.5367	0.5739	0.6369	0.6975	0.7692	0.8548
170	0.3956	0.4159	0.4371	0.4617	0.4890	0.5196	0.5556	0.6167	0.6752	0.7447	0.8274
175	0.3830	0.4027	0.4234	0.4474	0.4738	0.5036	0.5385	0.5976	0.6543	0.7215	0.8016
180	0.3710	0.3903	0.4105	0.4338	0.4595	0.4884	0.5222	0.5795	0.6345	0.6996	0.7772
185	0.3597	0.3786	0.3983	0.4210	0.4460	0.4740	0.5069	0.5624	0.6157	0.6789	0.7542
190	0.3490	0.3675	0.3867	0.4088	0.4331	0.4604	0.4923	0.5463	0.5980	0.6593	0.7323
195	0.3389	0.3570	0.3757	0.3973	0.4210	0.4475	0.4785	0.5309	0.5812	0.6407	0.7116
200	0.3292	0.3470	0.3653	0.3864	0.4094	0.4352	0.4654	0.5164	0.5652	0.6231	0.6920
205	0.3201	0.3375	0.3554	0.3760	0.3985	0.4236	0.4530	0.5026	0.5501	0.6063	0.6733
210	0.3114	0.3284	0.3460	0.3661	0.3881	0.4125	0.4411	0.4894	0.5356	0.5904	0.6555
215	0.3031	0.3199	0.3371	0.3567	0.3781	0.4020	0.4299	0.4769	0.5219	0.5752	0.6386
220	0.2952	0.3117	0.3285	0.3477	0.3687	0.3920	0.4192	0.4650	0.5088	0.5607	0.6225
225	0.2877	0.3039	0.3204	0.3392	0.3597	0.3824	0.4089	0.4536	0.4964	0.5470	0.6072
230	0.2806	0.2964	0.3127	0.3311	0.3511	0.3733	0.3992	0.4428	0.4845	0.5338	0.5926
235	0.2737	0.2893	0.3053	0.3233	0.3429	0.3646	0.3899	0.4324	0.4731	0.5213	0.5786
240	0.2672	0.2825	0.2982	0.3159	0.3350	0.3562	0.3810	0.4225	0.4623	0.5093	0.5652
245	0.2609	0.2761	0.2914	0.3087	0.3275	0.3483	0.3725	0.4131	0.4519	0.4978	0.5524
250	0.2549	0.2699	0.2849	0.3019	0.3203	0.3407	0.3643	0.4040	0.4420	0.4868	0.5402
255	0.2492	0.2639	0.2788	0.2954	0.3135	0.3334	0.3565	0.3954	0.4325	0.4763	0.5285
260	0.2437	0.2582	0.2728	0.2892	0.3069	0.3264	0.3490	0.3871	0.4233	0.4663	0.5173
265	0.2385	0.2528	0.2671	0.2832	0.3006	0.3197	0.3419	0.3791	0.4146	0.4566	0.5066
270	0.2334	0.2475	0.2617	0.2775	0.2945	0.3133	0.3350	0.3715	0.4063	0.4474	0.4963
275	0.2286	0.2425	0.2564	0.2720	0.2887	0.3071	0.3284	0.3642	0.3982	0.4385	0.4864
280	0.2240	0.2377	0.2514	0.2667	0.2831	0.3012	0.3221	0.3571	0.3905	0.4300	0.4769
285	0.2195	0.2331	0.2466	0.2617	0.2778	0.2955	0.3160	0.3504	0.3831	0.4218	0.4678
290	0.2152	0.2286	0.2420	0.2568	0.2726	0.2901	0.3102	0.3439	0.3760	0.4139	0.4590
295	0.2111	0.2243	0.2375	0.2521	0.2677	0.2848	0.3046	0.3377	0.3692	0.4064	0.4506
300	0.2072	0.2202	0.2332	0.2476	0.2629	0.2798	0.2992	0.3317	0.3626	0.3991	0.4425
305	0.2033	0.2163	0.2291	0.2433	0.2584	0.2749	0.2940	0.3259	0.3563	0.3921	0.4348
310	0.1997	0.2125	0.2251	0.2391	0.2540	0.2703	0.2890	0.3204	0.3502	0.3854	0.4273
315	0.1961	0.2088	0.2213	0.2351	0.2497	0.2658	0.2842	0.3150	0.3443	0.3789	0.4200
320	0.1928	0.2053	0.2176	0.2312	0.2457	0.2614	0.2796	0.3099	0.3387	0.3727	0.4131
325	0.1895	0.2019	0.2141	0.2275	0.2417	0.2573	0.2751	0.3049	0.3332	0.3667	0.4064
330	0.1863	0.1986	0.2107	0.2239	0.2379	0.2532	0.2708	0.3001	0.3280	0.3609	0.4000
335	0.1833	0.1954	0.2074	0.2204	0.2343	0.2494	0.2667	0.2955	0.3229	0.3553	0.3937
340	0.1803	0.1924	0.2042	0.2171	0.2308	0.2456	0.2627	0.2911	0.3181	0.3499	0.3877
345	0.1775	0.1894	0.2011	0.2139	0.2274	0.2420	0.2588	0.2868	0.3134	0.3447	0.3819
350	0.1748	0.1866	0.1982	0.2108	0.2241	0.2385	0.2551	0.2827	0.3088	0.3397	0.3764

ABSOLUTE VISCOSITY (CP) OF NaCl SOLUTIONS
PRESSURE = 15000psi

FILE NAME : VIS150

TEMP. DEG.F	SALINITY, percent by weight										
	0	2.5	5.0	7.5	10.0	12.5	15.0	17.5	20.0	22.5	25.0
150	0.4565	0.4789	0.5028	0.5307	0.5618	0.5969	0.6383	0.7085	0.7760	0.8560	0.9515
155	0.4404	0.4622	0.4854	0.5125	0.5425	0.5765	0.6164	0.6842	0.7493	0.8266	0.9187
160	0.4252	0.4465	0.4691	0.4953	0.5244	0.5573	0.5959	0.6614	0.7243	0.7989	0.8878
165	0.4110	0.4318	0.4537	0.4792	0.5074	0.5392	0.5766	0.6399	0.7007	0.7728	0.8588
170	0.3976	0.4179	0.4392	0.4640	0.4913	0.5222	0.5583	0.6197	0.6785	0.7483	0.8315
175	0.3849	0.4047	0.4255	0.4496	0.4762	0.5061	0.5411	0.6006	0.6576	0.7251	0.8056
180	0.3729	0.3923	0.4126	0.4360	0.4619	0.4909	0.5249	0.5825	0.6377	0.7032	0.7813
185	0.3616	0.3806	0.4004	0.4232	0.4483	0.4765	0.5095	0.5654	0.6190	0.6825	0.7582
190	0.3509	0.3695	0.3888	0.4110	0.4355	0.4629	0.4950	0.5492	0.6013	0.6629	0.7363
195	0.3408	0.3590	0.3778	0.3995	0.4233	0.4500	0.4812	0.5339	0.5844	0.6443	0.7156
200	0.3311	0.3490	0.3674	0.3886	0.4118	0.4377	0.4681	0.5193	0.5685	0.6266	0.6959
205	0.3220	0.3395	0.3575	0.3782	0.4008	0.4261	0.4556	0.5055	0.5533	0.6099	0.6772
210	0.3133	0.3304	0.3481	0.3683	0.3904	0.4150	0.4438	0.4924	0.5388	0.5939	0.6595
215	0.3050	0.3218	0.3391	0.3589	0.3804	0.4045	0.4325	0.4798	0.5251	0.5787	0.6426
220	0.2971	0.3136	0.3306	0.3499	0.3710	0.3944	0.4218	0.4679	0.5120	0.5642	0.6264
225	0.2896	0.3058	0.3225	0.3414	0.3620	0.3849	0.4115	0.4565	0.4995	0.5504	0.6111
230	0.2824	0.2984	0.3147	0.3332	0.3533	0.3757	0.4018	0.4457	0.4876	0.5373	0.5964
235	0.2755	0.2913	0.3073	0.3254	0.3451	0.3670	0.3924	0.4353	0.4762	0.5247	0.5824
240	0.2690	0.2845	0.3002	0.3180	0.3373	0.3587	0.3835	0.4254	0.4654	0.5127	0.5690
245	0.2627	0.2780	0.2934	0.3109	0.3298	0.3507	0.3750	0.4159	0.4550	0.5012	0.5562
250	0.2567	0.2717	0.2869	0.3041	0.3226	0.3430	0.3668	0.4068	0.4450	0.4902	0.5440
255	0.2510	0.2658	0.2807	0.2975	0.3157	0.3357	0.3590	0.3982	0.4355	0.4797	0.5323
260	0.2455	0.2601	0.2748	0.2913	0.3091	0.3287	0.3516	0.3898	0.4264	0.4696	0.5210
265	0.2402	0.2546	0.2691	0.2853	0.3028	0.3220	0.3444	0.3819	0.4176	0.4599	0.5103
270	0.2352	0.2494	0.2636	0.2795	0.2967	0.3156	0.3375	0.3742	0.4093	0.4507	0.4999
275	0.2303	0.2443	0.2584	0.2740	0.2909	0.3094	0.3309	0.3669	0.4012	0.4418	0.4900
280	0.2257	0.2395	0.2533	0.2687	0.2853	0.3035	0.3246	0.3598	0.3935	0.4332	0.4805
285	0.2212	0.2349	0.2485	0.2637	0.2799	0.2978	0.3185	0.3531	0.3861	0.4250	0.4714
290	0.2169	0.2304	0.2438	0.2588	0.2748	0.2923	0.3126	0.3466	0.3789	0.4171	0.4626
295	0.2128	0.2261	0.2394	0.2541	0.2698	0.2871	0.3070	0.3403	0.3721	0.4096	0.4542
300	0.2088	0.2220	0.2351	0.2496	0.2650	0.2820	0.3016	0.3343	0.3655	0.4023	0.4461
305	0.2050	0.2180	0.2309	0.2452	0.2604	0.2771	0.2964	0.3285	0.3591	0.3953	0.4382
310	0.2013	0.2142	0.2269	0.2410	0.2560	0.2724	0.2914	0.3230	0.3530	0.3885	0.4307
315	0.1978	0.2105	0.2231	0.2370	0.2518	0.2679	0.2865	0.3176	0.3471	0.3820	0.4235
320	0.1943	0.2070	0.2194	0.2331	0.2477	0.2636	0.2819	0.3124	0.3415	0.3758	0.4165
325	0.1911	0.2036	0.2159	0.2294	0.2437	0.2594	0.2774	0.3075	0.3360	0.3697	0.4098
330	0.1879	0.2003	0.2124	0.2258	0.2399	0.2554	0.2731	0.3027	0.3308	0.3639	0.4033
335	0.1848	0.1971	0.2091	0.2223	0.2363	0.2515	0.2689	0.2980	0.3257	0.3583	0.3971
340	0.1819	0.1940	0.2059	0.2190	0.2327	0.2477	0.2649	0.2936	0.3208	0.3529	0.3911
345	0.1790	0.1911	0.2029	0.2157	0.2293	0.2441	0.2611	0.2893	0.3161	0.3477	0.3852
350	0.1763	0.1882	0.1999	0.2126	0.2260	0.2406	0.2573	0.2851	0.3115	0.3426	0.3796