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**INJECTION, INJECTIVITY AND INJECTABILITY
IN GEOTHERMAL OPERATIONS: PROBLEMS
AND POSSIBLE SOLUTIONS**

Phase I — Definition of the Problems

By
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MASTER

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**U. S. DEPARTMENT OF ENERGY
Geothermal Energy**

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PREPARED BY

O.J.VETTER* AND H.B.CRICHLOW**

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1.0 ABSTRACT

A definition study on geothermal reinjection problems was conducted. The wide spectrum of problems related to the reinjection of heat-depleted brines was outlined. Emphasis was focused on problems relating to both injectivity* and injectability**.

The main objectives of the study were to define the problems and to suggest further R&D work. It can be stated that the geothermal reinjection technology is in desperate need of development. No refined and readily useable technology for reinjection seems to exist.

The problems addressed in the report can be broken down into three major categories:

1) Top priority or critical:

These problems must be solved for the geothermal industry to survive.

2) Medium priority or serious:

These problems should be attacked to allow an economic operation of the geothermal industry.

3) Low priority:

These problems should be handled to improve the cost-efficiency and provide long-term stability of the geothermal industry.

Top priority problems include:

- 1) Suspended particles and their effects on injectability and injectivity.
- 2) Scale formation in the entire injection system.
- 3) Well stimulation techniques must be developed.
- 4) Need for new tracer technology is strongly indicated.
- 5) Organizational difficulties.

* Injectivity is defined as a measure of the wellbore and reservoir ability to take the injected fluid (wellbore and/or reservoir phenomenon).

** Injectability is defined as a measure of the suitability of the injected fluid for injection (fluid phenomenon).

- a) Coordination between domestic (private and governmental) and foreign R&D efforts.
- b) Logical sequence and utilization of theoretical, laboratory and field investigations.
- c) Speedy and operations-oriented technology transfer.

Medium priority problems include:

- 1) Improvement of engineering technology used for optimization of energy recovery through proper heat-mining.
- 2) Major environmental problems in combination with technology aimed at improvement of reinjection operations.
- 3) Improvement of drilling and well completion technology.

Low priority problems include:

- 1) Fundamental research not directly related to solving top and medium priority problems.
- 2) Minor environmental problems which still permit operation within guidelines of compliance.

This report proposes an R&D framework to solve many of the outlined problems. It involves:

- 1) A coherent combination of theoretical, laboratory and field experiments.
- 2) Transfer of advanced technology from other fields of science and its adaption to geothermal operations.
- 3) Coordination of R&D work aimed at solving production and injection problems.

The investigations described in this present report represent an effort of approximately 3.5 man months.

2.0 OBJECTIVES

The main objectives of this study are to:

- 1) Determine and outline major injection, injectivity and injectability problems in geothermal operations through:

- a) Evaluating the data published in the open literature.
 - b) Utilizing personal experiences in this field.
 - c) Retrieving data, thoughts, and ideas from others working in this area.
 - d) Attempting to apply know-how from similar or related technologies, particularly from the oil and gas fields to the geothermal industry.
- 2) Suggest and/or recommend possible solutions, further research and field investigations to overcome these problems. Heavy emphasis must be placed on practical solutions which can be immediately applied to field operations to accomplish DOE's goal: "Power on Line". Priority and accomplishing of recommended tasks should enable the operators to receive optimum benefits from this study at the earliest possible time. The emphasis should be placed on investigations having a short and mid-range term impact (1-5 years) on field operations. Long-term impacts (more than 5 years) should also be outlined but not over-emphasized.

3.0 CONCLUSIONS

As shown in this report, no refined and readily useable technology for reinjection of heat-depleted brines exists at the present time. The development of this new technology is urgently suggested. The required R&D work in this field is too costly and time-consuming to be left to the private industry. The U.S. Department of Energy is urged to participate in an all-out R&D effort to solve at least the most pressing problems. It is suggested to coordinate these R&D efforts with the private industry within the United States and also with R&D groups abroad, particularly in Mexico, Italy, Japan, New Zealand and, possibly, in San Salvador.

The complexity of the injection problems cannot be over-emphasized and is not limited to injector-wellbore plugging as frequently assumed. We would like to point out that only an all-out effort started immediately will prevent further disasters in the geothermal industry within the United States.

A "piece meal" approach or unorganized development work as done in the past will inevitably lead to insufficient support of the industry and, in the worst case, may result in the loss of some of our best geothermal reservoirs. We would also like to warn of a commonly observed approach: transfer of oilfield water injection technology into the geothermal field without the necessary adjustments. Geothermal reinjection will differ considerably from oilfield reinjection.

4.0 SUGGESTIONS AND RECOMMENDATIONS

One of the main conclusions of this present definition study is that the reinjection technology in geothermal operations is in desperate need of further development. The following suggestions and recommendations can be made after completing the study:

A. General Problems of Importance

1) Coordination of domestic and foreign efforts to solve geothermal injection problems is urgently recommended. The three main groups interested in these problems are (a) DOE/DGE, (b) private domestic companies and (c) foreign governments and operators. This recommended coordination could be accomplished by:

a) Coordinate immediately R&D work sponsored by government and private industry within the United States. Preliminary discussions with private operators have indicated an extremely strong interest in this matter. It can be shown to the private industry that only this cooperation will result in a reasonable cost for R&D work without generating new technical disasters and costly delays of field developments.

b) Coordinate the R&D work with efforts presently undertaken by foreign governments and operators. Preliminary discussions with technical personnel in Mexico and Italy showed that Mexican and Italian researches are strongly interested in a cooperative effort.

c) Appoint a technical coordinator through DOE/DGE. Most important, this coordinator must be familiar with the external and internal problems of the private industry. He must respect the proprietary situation and competitive character of the industry. He must also be thoroughly familiar with laboratory research and experimental field work. No field experiments should be suggested that may endanger any of the present or planned field installations including the injection wells and reservoirs. This technical coordinator either must have the confidence of the industry or must be able to win it in a short time.

It may be advisable that this appointed industry coordinator is the professional who also coordinates the efforts of the DOE/DGE research program on the improvement of geothermal production wells. His main job should be to coordinate all DOE/DGE and industry efforts (domestic and foreign) to solve injection, injectivity and injectability problems.

2) A new study of the injection, injectivity and injectability problems is suggested. The proposed study must include some sophisticated research but should not over-emphasize basic research to the point of diminishing return. The proposed study must emphasize practical

solutions based on sound engineering within the shortest possible time. The results of the proposed work must be applicable for geothermal fields immediately to accomplish DOE's main goal: "Power on Line!"

3) The proposed study does not only include laboratory and theoretical research but also field experiments to a limited degree. This combination is very much desired because the validation of experimental and analytical work demands an immediate interactive environment between the laboratory and field operations. Only field experiments can provide the final proof for the validity of all laboratory and theoretical results.

4) The proposed study of injection problems should be closely coordinated with another study on production problems. Several research tools and methods required for both studies are very similar in nature. This close research coordination between the two organizations will result in substantial savings regarding research funds and time. The cost for the proposed study of injection problems can be cut significantly if the studies are performed simultaneously. However, it is suggested to keep the two studies (production and injection problems) as two different entities as far as funding and management are concerned because there are also dissimilar features in the two research efforts. Since the proposed study of injection problems includes not only pure laboratory and theoretical research, but also actual field experiments, further savings can be achieved through coordination of some of these efforts.

5) Many tasks suggested in the proposed study require laboratory studies followed by field experiments. These field experiments can be conducted and funded in three different ways:

a) Some of the field experiments will require amazingly little funding and should be supported fully by DOE/DGE within this proposed study. Tracer jobs, reservoir monitoring and measuring of brine quality parameters are typical examples. Preliminary discussions with private operators have indicated that a DOE/DGE contractor would have full access to fields and well sites to conduct these experiments in return for relating all relevant information to the operator.

b) Other field experiments such as well stimulation jobs are expensive and entail a high risk for field installations. It may be too difficult to convince the operator to bear the full cost of these experimental jobs. DOE/DGE may have to provide the funding for these jobs. Some operators indicated their interest in providing well sites for experimental jobs. The magnitude of the required field jobs is such that a separate contract on these jobs should be awarded. An organization experienced in managing complex and sophisticated field experiments should be considered.

c) Some operators are planning to stimulate their wells even without funding provided by DOE/DGE. It is suggested to provide technical support and field job monitoring to the operators in return for the information gathered from these field jobs.

6) Highly efficient and speedy technology transfer must be ensured. Dissemination of the collected data and conclusions into the public domain should be of top priority. Publication of the data through professional journals (e.g., Journal of Petroleum Technology) should be performed. Special or specific topics can be published prior to the completion of the final reports to accelerate the dissemination of the information.

B. Suspended Particles and Their Effects on Injectability and Injectivity

1) Particle analysis of all suspended matter in the injected brine is the key to maintenance-free injection wells. Proper methods for instantaneous measurements of particles, their size, size distribution, population, shape, consistency and composition as a function of thermodynamic and kinetic conditions must be developed. These measurements must be instantaneous at various locations in a flowing brine. These measurements are not only required to investigate and understand the effects of particles on injectivity but also provide a desperately needed means for constant brine quality control in the field.

2) Millipore filter tests as commonly done in oilfields are almost useless and can lead to totally false conclusions. They must be replaced by more appropriate methods.

3) Particles not only fill up or plug wellbores and the sandface but can also penetrate into the reservoir thus causing deep penetration damages. Effects of the particles on the permeability of actual core materials should be reevaluated using newly developed experimental procedures. These new core flood test work will allow one to evaluate the movement of particulates through cores.

4) The data from particle measurements and core flood tests should be used to develop proper correlations between particle and reservoir parameters. These correlations must consider the permeability variations with depth in the wellbore and with distance from the sandface. The goal is to develop mathematical models to explain and document the various correlations. These models can be used to determine and maintain minimum standards of brine quality during injection.

5) The use of chemicals to aid the removal of suspended particles should be studied in more detail to obtain the required minimum standards of brine (injectability). Adding of additives to various brines should be done in a technically and scientifically correct manner. Previous "shot-gun" approaches are too expensive and time-consuming. These

approaches may lead to discarding many potentially useful chemicals because they do not allow the proper study of the complex and critical "concentration-time-composition" correlations. These correlations as well as the basic flocculation reactions should be studied in minute detail.

6) The use of mechanical clarification processes such as reactor clarifier and Wemco units should be studied in more detail. Preliminary results in the Niland area were very encouraging. These experiments should be extended to different geographical areas. However, these new experiments should also include the use of chemicals (flocculants) and proper monitoring instrumentation.

7) Experiments regarding the use of chemicals for removal of suspended particles alone or in combination with mechanical clarifiers, should involve highly sophisticated monitoring techniques. These techniques should include instantaneous monitoring of the particle geometry and the use of chemicals labeled with radioactive isotopes to study the actual reaction mechanisms. Preliminary contacts with a major chemical manufacturer showed a strong interest by the chemical industry. These experiments could easily be conducted in a cost-sharing program.

8) Suspended particles can originate in the producing reservoir or can be formed by precipitation reactions. The particles formed by precipitation can constantly change their geometry due to the changing thermodynamic conditions. Special attention should be paid to this changing geometry and its effects on injectivity and injectability. Precise measurements to determine this complex phenomenon should be investigated in the proposed study.

C. Scale Formation in Injection Wells is Still A Major Problem

1) Much of the present scale formation in geothermal injection systems would be avoided by handling the problem with either chemical additives or pressure and temperature manipulations in the field. One of the more important problems is the dissemination of already available information to the operators.

2) Each scale-forming compound acts differently as a function of pressure and temperature changes. The most frequently encountered scales in geothermal injection systems are silica, carbonates, sulfates and sulfides. Proper modeling of the thermodynamic behavior of each of these classes of chemicals must be done at the earliest possible time to allow the operator to understand his very special, site-specific problems. Present scale models are too complicated, costly to run, ignore the critical pressure effects and/or lead to false predictions. Preliminary modeling of sulfate scales using a more realistic and complete data base and a more effective and less time-consuming code has shown that proper modeling can be done more cost-effectively and accurately

than previously indicated. This new thermodynamic model can easily be expanded to the other three classes of scale (carbonates, sulfides and silica). These models should be completed within the very first phases of the proposed study. They should be tailored to the application in geothermal injection systems as our current scale models (VESCAL series) and not to geological considerations as many of the published models.

3) A more complicated problem is caused by combining a workable scale prediction model with reservoir modeling. This would allow us to predict the effects of scale formation not only for the injection wells but also for the entire reservoir including the production side. The value of the "overall" modeling will depend upon the development of proper correlations between porosity and permeability in the process of scale deposition in the reservoir. It is strongly suggested to attempt the generation of the "overall" scale-reservoir model using presently available reservoir simulators, newly developed scale prediction models and the suggested experimental "porosity-permeability" correlations.

4) The required scale prevention is not limited to flash cycles as commonly assumed. Binary systems can also exhibit severe scale problems in the injection wells. It is suggested to experiment in areas where the most severe scaling cases exist in binary and flash cycle systems. Actual field experiments should prove that scale inhibition using properly selected chemicals can be accomplished with excellent economics. It is presently felt that carbonate and sulfate scales can be avoided even under the most severe scaling conditions. More research is required to combat the silica scale experienced during the reinjection of brine produced from high temperature reservoirs.

5) Chemical additives used to prevent the formation of scale and wellbore plugging particles should be studied. Emphasis should be placed not only on the preventive effects of these additives but also on the negative side effects of these chemicals.

6) Precise solubility measurements of scale and particle-forming solids must be performed under simulated thermodynamic reservoir conditions. The kinetics of the particle formation must also be studied. Results of ongoing research contracts in this area funded by DOE/DGE should be validated in a limited number of laboratory tests using radioactive tracer methods.

D. Well Stimulation Methods Should be Tested

1) Various acids (HCl and mixtures of HCl/HF), bases (e.g., NaOH) and chelating agents (EDTA, NTA, etc.) have a good potential for stimulation of injectors if scale or suspended particles have caused wellbore damage. The thermodynamics and kinetics of the dissolution reactions with the various stimulation fluids should be reevaluated even though an extensive

number of literature references are available. Recent field experience has shown that the thermodynamics and kinetics of the dissolution reactions at the high temperatures are more complicated than described in the literature. A lab study of this problem is suggested. This lab study would be an extension or addition of the study already covered under a DOE/DGE contract on stimulation of producing wells. This extension will be concerned with the specific conditions of injection wells.

2) Of high interest are also the effects of various stimulation fluids on naturally low permeability (reservoir rock components) and damaging materials formed during drilling and completing the wells.

3) A field study on stimulation of injection wells is suggested. The lab data (see above) should be applied to design a limited number of injector stimulation jobs. The spent fluids after each stimulation job should be produced back and analyzed for their precise chemical composition to evaluate all downhole reactions and the effectiveness of all additives used in the jobs. This includes the efficiency of all stimulation fluids used for removing the wellbore damage as well as the effectiveness of the corrosion inhibitors used.

4) It is also suggested to start an industry support program for stimulation of injectors. This program will not include actual stimulation jobs but technical support to various operators in designing and evaluating field jobs aimed at stimulation of injectors.

E. Need for New Tracer Technology is Strongly Indicated.

1) A new tracer technology must be developed to monitor the unpredictable advance of a cool temperature front from the injectors toward the producer before severe temperature damage occurs in the producing reservoir of wells. Conventional reservoir engineering through rate, pressure and/or temperature test work and analysis is not sufficient for the required surveillance and reservoir verification due to the uncertainties regarding the reservoir heterogeneities. Conventional reservoir engineering should be supplemented by this tracer technology. Every new injection project in the field should involve these tracers from the start of brine reinjection. Using the tracer techniques as a prewarning system will allow the operators to stop injection and to take proper steps to redesign his injection system before irreparable damage occurs.

2) Tracers suitable for the high temperatures in geothermal reservoirs are limited to a small number. Tritium in the form of tritiated water seems to be the most suitable tracer. However, additional tracers must be found to evaluate the wide range of reservoir problems.

3) All potential tracers must be evaluated in laboratory studies for their suitability in geothermal reservoirs. The high temperature

behavior of tracers, particularly their hydrothermal stability and adsorption isotherms, must be determined in great detail. These hydrothermal and adsorption/desorption characteristics of potential tracers must be studied in the laboratory prior to field applications.

4) Tracer chromatography methods should be evaluated for geothermal reservoir applications. This new method will allow an optimized reservoir management. This may turn out to be of utmost importance for the most economical exploitation of our sometimes marginal reservoirs.

5) Sophisticated and field oriented mathematical modeling of the observed tracer effluent profiles is required. Preliminary studies have indicated that this goal can be achieved within a fairly short time. This modeling cannot be performed without conducting a laboratory study on the adsorption/desorption characteristics of all suggested tracers.

F. Improvement of Engineering Technology Used for Optimization of Energy Recovery Through Proper Heat-Mining Must be Emphasized

1) Optimum heat-mining and, at the same time, prevention of subsidence should be attempted by importing injection water to the field. An additional benefit and economical stimulus of this method for the operators would be the possibility of selling the highly valuable condensate for irrigation purposes. The political impact of this method would also be highly welcome to the geothermal industry.

2) The large disadvantage of this method of importing injection waters would be the problems generated by chemical compatibility problems. The chemical compatibility problems can also be caused by reinjection of produced water into the identical reservoir from which it originally came. Thermodynamic conditions during production can drastically change the composition of the produced water, thus rendering it incompatible with the original reservoir water. Preliminary lab and field studies for a foreign operator have shown that even extreme compatibility problems may be handled in an economically and technically feasible way. However, this method, its pros and cons, should be studied more carefully to avoid future reservoir and production problems.

3) Methods and preliminary models of the chemical compatibility problems are already available. Comparatively small efforts are required to "debug" the present models and extend them to a wider range of applicability.

4) The major problem is to combine the new chemical models with more conventional reservoir models. This combination is feasible and should be attempted immediately.

G. Environmental Problems Deserve a Closer Study

1) Potential and real dangers regarding environmental pollution problems exist in geothermal operations. The main dangers are caused by gases and liquids entering the environment in undesired quantities. Proper reinjection of all gases could be used to avoid these pollution problems. This possibility should be investigated.

2) The investigations of gas pollution per se is not suggested but the possibility of flashing or partially flashing the gases without releasing these gases into the environment should be evaluated. After bypassing the power plant, the partially vented gases could be recombined with the brine partially depleted in its gas concentration and the mixture could be reinjected. This bypass vent process could result in substantial savings for power plant construction. Thus, economical and environmental problems could be solved at the same time. This vent process should be studied in detail.

3) To investigate the suitability of gas reinjection with and without gas venting, the effects of dissolved gases on the chemical and physical brine properties should be modeled for all surface and downhole conditions. It is suggested to study and model the solubility behavior of all reactive gases (CO_2 , H_2S , NH_3) to determine the effects of dissolved and/or free gases on injectivity. This is especially important for pH control to maintain a scale-free environment. Preliminary efforts to model CO_2 and N_2 behavior have indicated that correct modeling of gases can be accomplished with a great degree of reliability. This previous work should be extended to cover the entire range of ionic strength of geothermal brines. This modeling should also cover other gases such as NH_3 and H_2S present in geothermal brines.

H. Drilling and Well Completion Technology Needs Improvement but Should be Handled Through Other DOE/DGE Programs

1) Drilling and completion of injection wells in geothermal fields are in need of improvement. High temperature drilling and completion fluids should be evaluated as to their damaging effects during drilling and completion. However, this work is already proposed through LASL and a major DOE/DGE contract is awarded. The critical properties of drilling and completion fluids will be determined through this other contract.

2) The hardware aspects of drilling and completion technology will also be evaluated in the above-mentioned contract. It is, therefore, at the present time, suggested not to fund a new research and evaluation program on the injection well drilling and completion technology.

5.0 INTRODUCTION - INJECTION, INJECTABILITY AND INJECTIVITY: STATEMENT OF THE PROBLEM

The geothermal industry, still in its infancy, is plagued by a number of problems. Injection of heat-depleted brine and injectivity deterioration of injection wells is a major problem. One can safely state that geothermal energy will not play a major role within the United States unless these injection problems are solved, or at least managed in a technically and economically feasible manner.

As shown in this report, proper injection of heat-depleted brine is quite different from a simple disposal of the brine by injection into disposal wells. The distinction between a disposal well and an injection well is determined by the underground reservoir used to accept the heat-depleted brine. An injection well is completed within the same reservoir where the brine originated (producing reservoir), whereas the disposal well may be completed in any strata or reservoir but the producing reservoir. For example, the condensate water in some leases in the Geysers (Northern California), a dry steam reservoir, are "injected" into disposal wells (Union Oil Geothermal). However, these disposal wells may act partially and inadvertently as injection wells.¹

Disposal wells^{2,3} are suited to solve disposal and environmental problems but are unfit for a proper and optimized energy extraction from a liquid-dominated geothermal resource. The productivity of a confined reservoir without reinjection has been evaluated in numerous publications^{4,5} and must be considered uneconomical compared to the production of a reservoir with proper reinjection.⁶⁻¹³

This present report is concerned with most problems and aspects of proper and optimized injection even though many of the comments and recommendations are also applicable to the less desirable disposal wells.

Basically, the problems encountered during injection of the heat-depleted brine can be separated into two major categories:

- 1) Problems caused by declining of an originally high injectivity.
- 2) Problems generated by a naturally low injectivity.

Describing the various effects leading to a declining injectivity with time and an evaluation of potentially preventive and remedial procedures is an extremely complicated and difficult task. A decrease of injectivity can have a great many different causes. Many of these causes are interrelated. A large number of the individual effects are small and may not deserve much attention by themselves. However, a combination or summation of these fairly small effects can lead to drastic reductions of a previously sufficient injectivity. Also, synergistic effects cannot be ignored.

A report such as this present one can follow different guidelines or structures. The authors feel that any written description of geothermal injectivity declines, their causes, and the prevention and removal of wellbore and formation damage will follow more or less arbitrary guidelines because of the extreme complexity of this topic. In addition, any preventive or remedial procedure must be related to the many causes of a specific decrease or loss of injectivity. All interrelations of these causes must be considered in the body of a report, thus rendering the structure of any report very complex or even "illogical". Therefore, a certain degree of patience must be expected from the reader.

One can compare the problem of injectivity decreases or losses with a human illness. It is common knowledge that an illness cannot be cured by fighting symptoms. Only recognizing the causes of the illness and effectively treating these causes can lead to the desired health. Therefore, the present report follows the basic outline starting with a description of the various causes of injectivity decreases and the effects leading to these causes. Then, remedial and preventive procedures are suggested. Only a few of the suggested remedial and preventive procedures have been tried in actual field operations. The experimental laboratory and field work required to underline and prove the present evaluations are the subject of PHASE II of this research program.

The open literature contains a number of publications related to injection problems in geothermal operations. However, none of these publications can be considered a comprehensive and exhaustive treatment of the geothermal injection problems.

The most recent attempts to shed some light on the complex problems were performed under the sponsorship of the U.S. Department of Energy, Division of Geothermal Energy (DOE/DGE).¹⁴⁻¹⁷ Much of this work is cited in this report. However, some of the more site-specific work performed by the private industry did not find its entry into the public domain and may remain proprietary information.

DOE/DGE decided to undertake another attempt to shed some light on the injection problem in its entirety. This attempt will be conducted in three (3) phases:

- 1) PHASE I: Definition of the problems (this present report).
- 2) PHASE II: Theoretical and experimental study including a limited number of field experiments.
- 3) PHASE III: Extended field study including experimental well stimulation jobs.

This present report is the result of the first phase, namely the definition of the problems. The work described in this report represents an effort of approximately 3.5 "man months" conducted during a period of five (5) months.

6.0 THERMODYNAMIC INSTABILITY OF BRINE

Exceeding the thermodynamic limits of geothermal brines can lead to major injection problems. As a result, solids and gases are formed and can clog up flow channels and entire injection systems.

Changes of the thermodynamic conditions of the brines are almost constant during brine production, utilization, and injection in geothermal operations. Any volume unit of flowing brine will constantly change its pressure, temperature, chemical activity, enthalpy, entropy, etc. Naturally, these changes of thermodynamic conditions are also found to varying degrees in other flowing systems and are not limited to geothermal operations. However, the detrimental effects caused by these thermodynamic changes in geothermal operations are tremendously larger than those encountered in most other industrial operations producing fluids from subterranean reservoirs (oil, gas, supply water, leach mining, etc.). In addition, the large flow rates inherent to geothermal operations will cause a magnification of these detrimental effects. Even if these effects per unit volume would be very small, the cumulative effects could be very large.

Both temperature and pressure drops in common geothermal operations are usually so large that the thermodynamic stability of the brine in the injection system is almost always exceeded. Gas, including water vapor, may break out of solution,¹⁸ thus further magnifying the degree of changes of certain other thermodynamic parameters, especially the concentration related variables. The concentration of some brine components will increase as gas, particularly water vapor, is evolving. This leads to rapid and drastic changes of the chemical activities and potentials in these brines. For example, it is not unusual that the concentration of dissolved ions increases by 10-20 percent and the pH value jumps from 6 to 9 or even higher within a few seconds during a flash process.¹⁸

One has to remember that the brine in the producing reservoirs is saturated with respect to the native rock materials. The saturation conditions for all brine components are mainly dictated by the pressures and temperatures of the reservoir. The pressures and temperatures found in geothermal reservoirs are on the order of a few hundred atmospheres and as high as a few hundred degrees centigrade, respectively. As the brine is produced, utilized, and reinjected, the pressures and temperatures may rapidly drop to almost atmospheric pressure and a temperature on the order of 100°C and below. These pressure and/or temperature drops, in return, will render the brine supersaturated in respect to one or more solutes, thus leading to gas evolution and/or precipitation reactions.¹⁸⁻²¹

The complexity of the physical and chemical reactions accompanying these rapid changes of thermodynamic properties can be mind-boggling. Almost invariably, these reactions will lead to the formation of new

phases (gases and/or solids), thus causing some of the most annoying problems in geothermal operations. Therefore, it can safely be stated that a thorough understanding of the chemical thermodynamics is absolutely necessary for these operations. Thermodynamic stability problems regarding the fluids must be understood and quantitatively described before the major problems regarding a technically successful geothermal operation can be solved.

6.1 Degree of Supersaturation and Precipitation Reactions

As soon as a brine becomes supersaturated with respect to a solid component of any kind due to a change of the thermodynamic conditions, the potential for precipitation reactions, i.e., particle and scale formation, will be generated. Exceeding the point of saturation and entering the concentration range of supersaturation does not mean that precipitation reactions, and with that, the formation of particles and/or scale will immediately occur. The actual degree of supersaturation at any point or time in a geothermal installation will determine the type and rates of reactions leading to particle and/or scale formation. This degree of supersaturation by itself, of course, is a complex function of the thermodynamic conditions.

As a rule, any precipitation reaction will proceed faster, the higher the degree of supersaturation. In addition, the chemical compositions and physical characteristics of the particles and scale formed as a consequence of precipitation reactions also depend upon the degree of supersaturation. Therefore, it becomes rather obvious that the degree of supersaturation (as the driving force for particle and scale formation) is of utmost importance for all geothermal injection problems related to particle and/or scale formation.

The literature¹⁸⁻¹³⁶ contains a large number of publications dealing with or related to the solubility behavior of various components frequently encountered in geothermal brines (see Table 1). The list of literature references given in this report is far from complete. Unfortunately, most of the relevant publications are concerned only with the thermodynamics of the solubility and not with the kinetics of the precipitation reactions leading to particle and scale formation.^{137,138}

Thermodynamic reactions determine only equilibrium conditions, i.e., the solubility of a component as a function of temperature, pressure, etc., whereas, the kinetic reactions describe the reaction rates, i.e., the speed with which a reaction proceeds to its completion as a function of the degree of supersaturation and other thermodynamic properties.

The kinetics of some basic precipitation reactions found in geothermal brines are also described to a certain degree in the literature.¹³⁹⁻¹⁷² Here again, the referenced literature is far from being complete. Very few of the referenced investigations deal with the precipitation kinetics actually encountered in the complex geothermal brine systems.

It seems that additional knowledge should involve all reactions leading to precipitation (i.e., scale and particle formation).

Table 1 lists the types of solid components commonly found in geothermal particles and scales. These solid components formed by precipitation reactions are caused by changes of the thermodynamic conditions in geothermal brines and should not be mistaken for other types of particles stemming from different origins as outlined in later paragraphs of this report.

6.1.1 Lack of Reliability of Published Data

Unfortunately, some of these published solubility data given in the references are very unreliable or doubtful at best for various reasons:

1) The actual measurements of the solubility frequently involved inadequate methods. For example, earlier solubility determinations relied heavily on conductivity and potentiometric measurements. These analytical methods must be considered extremely inaccurate and inadequate for a number of reasons.

Figure 1 illustrates one of the major problems encountered with solubility determinations by conductivity measurements. The total specific conductivity of a geothermal brine can be very high, whereas the partial conductivity due to the compound of interest (BaSO_4 in the system shown in Figure 1) can be very low. In this case, the difference between the total conductivity and the partial conductivity of interest is extremely large, thus causing severe accuracy problems during the actual measurement and with that, a high degree of unreliability. This problem will always exist when the solubility of sparingly soluble salts in brines is measured by this method.

Another source of errors is the formation of complex ions frequently found in aqueous solutions. The mentioned analytical methods can result in large errors if the ions of interest form complex or coordination compounds (chemical complexes) of unknown structures or are not accounted for in the evaluation of the actual measurement. A typical case is silver sulfide. The solubility measurement considering only the reaction:

will result in one set of data. However, the true reactions in the liquid phase during precipitation are much more complicated.¹⁷³ Various ions can form a number of fairly soluble ionic complexes. The following three equations list only a number of the possible ionic complexes:

and

and

Equations (2), (3) and (4) indicate the existence of at least three silver containing compounds or ions besides the Ag_2S in the aqueous system of Ag_2S and H_2S . Mehra¹⁷⁴ showed that there exists at least one more ionic complex, namely $\text{Ag}_2 [(\text{SH})(\text{OH})]$. Conductometric and/or potentiometric solubility determinations may result in wrong values if these complexes are not considered. As an example, Figure 2 shows both the potentiometric determination of the Ag_2S "solubility" and the real solubility determined by radiometric measurements.

The older potentiometric and/or conductometric determinations of the Ag_2S "solubility" can result in values that are much smaller than the true solubility. The "measured" and the true solubilities can differ by a factor of 10^{17} . This behavior explains the relatively larger silver and silver sulfide deposition from the Niland and Brawley brines. These depositions cannot be explained through the older high temperature solubilities of Ag_2S published in the literature. Unfortunately, the newer and more reliable literature^{173,174} lists only the low temperature data.

Without a precise knowledge of the reaction mechanisms, solubility measurements using conductivity and/or potential measuring devices will invariably lead to false and misleading data. This is one of the main reasons why much of the solubility data published in the open literature must be considered with extreme caution.

2) Analytical and experimental problems encountered during actual solubility measurements are another main source for errors. In the past, we outlined this problem in the case of BaSO_4 solubility determinations.²⁰ Templeton²² published his data for the temperature range between 25° and 95°C, whereas, Uchameyshivili¹⁷⁵ lists his data for temperatures from 100° to 370°C. Unfortunately, the data from both references are not in good agreement. Uchameyshivili's data are almost 25% lower than Templeton's data at or close to the 100°C mark. This is absolutely unsatisfactory for any modeling of the precipitation reactions. The question as to whose data are right still remains wide open.

3) The solubility of many sparingly soluble compounds not only depends upon pressure, temperature and chemical activity of the aqueous solutions but quite often can be unexpectedly high or low due to the formation of coordinative (complex) compounds. Typical examples are the heavy metal sulfides (see above) and also the alkaline earth metal sulfates. The solubility of some of these alkaline earth

metal sulfates can vary greatly from simple systems (only one kind of alkaline earth ions is present) to more complicated and complex systems in which the brine contains more than one kind of alkaline earth ion.

The very few data published on the solubility behavior of these sulfates in complex systems^{24,39,176} (mostly below 100°C) show considerable differences from those in simple systems.^{22,175} These differences may or may not be larger at higher temperatures for which no such data exist. Ignoring these differences by measuring the solubilities only in simple systems (containing only NaCl and the compound of interest) will certainly result in a questionable data base to be used for future chemical modeling. Our more practice-oriented evaluation of literally thousands of oilfield and geothermal brines^{18,19,20,137,138} for their scaling tendency proved this point over and over. We found only a very few cases of scaling brines where the actually measured ionic product matched the calculated solubility product using published data on simple systems.

4) "Conventional" high temperature solubility measurements are frequently hampered by an additional problem: the solid phase may change under the conditions encountered during the actual measurement and form a new crystal modification having a totally different solubility behavior than the original compound. The phase transitions of "quartz-amorphous silica" and "gypsum-anhydrite" are only a few examples. We have found a number of new crystal modifications under high temperature conditions not previously expected.^{137,177} A new type of a silicate¹³⁷ was found in a Cerro Prieto well and a new arsenic sulfide modification¹⁷⁷ was detected in a 350°F gas-water well. Solubility measurements and studies of the kinetics of any precipitation reaction without a thorough knowledge of these solid phase transitions can also lead to erroneous results. Therefore, any evaluation of the precipitating compounds at high temperatures must also include the study of this phase behavior.

This unreliability of the thermodynamic data, i.e., the uncertainties in our knowledge of the saturation concentration as a function of thermodynamic conditions causes large uncertainties in the highly desired modeling of the precipitation reactions. We must remember that these thermodynamic conditions and their changes lead to the critical particle and scale formation and, therefore, must be accurately determined and known. No prediction of particle and scale formation will be possible without these reliable solubility measurements and/or determinations of basic thermodynamic data considering all chemical reactions in solution under simulated field conditions.

6.1.2 Modeling of Scale Formation Due to Brine Instability

One of the keys to proper brine injectability is the correct modeling of the scale formation in geothermal systems.¹³⁷ Any of the desired

models must predict the formation of scale under field conditions. This means, the thermodynamics, kinetics and hydrodynamics of all reactions leading to scale formation must be known and mathematically described. To complicate things even further when scale forms it will occupy some of the space previously filled with fluid. The resulting narrowing of the flow paths will have a pronounced effect on the thermodynamics, kinetics and hydrodynamics. This, in turn, will affect the scale formation reactions, thus leading to an extremely complicated and in most cases self-aggravating situation.

It may appear that it is too difficult to describe this complex situation mathematically. However, the authors feel that the major problems of scale formation under field conditions can be predicted in a practical manner. Instead of using or modifying existing scale prediction models,¹⁷⁸⁻¹⁸² the authors modeled the solubility and precipitation behavior in a different way.¹⁸³

An entire series of models was developed. They consist of small "building blocks" which can be arranged in larger blocks, used alone or combined with various types of reservoir simulators (see later in the report).

The basic idea is to keep the models as simple as possible and to include the most important parameters leading to precipitations and scale. The most important parameters are:

- 1) Temperatures
- 2) Pressures
- 3) Brine compositions
- 4) Flow rates

Temperature effects are included in other models too.¹⁷⁸⁻¹⁸² However, pressure effects are greatly neglected. A decrease of pressure without changing the temperature counts for many scale formations in the field.^{19, 20, 137, 138} Ignoring these pressure effects, of course, will not permit one to predict skin and many wellbore damages due to scales which are formed by pressure drops at constant or near constant temperature.

The brine compositions are also critical. In order to calculate solubilities using basic thermodynamic functions, one must have access to measured basic thermodynamic data, determine the ion activities and then calculate the solubilities. Calculating or determining the necessary equilibrium constants requires a thorough knowledge of the reaction mechanisms in the liquid phase. These reaction mechanisms and with that the kind of complexes dissolved in the brine, depend not only on ionic strength (as assumed in other codes) but also on the kind of species in solution. This can be shown by comparing solubilities at constant ionic strength

but different composition of the brine.²⁴ This is also indicated by our own preliminary laboratory studies.

Neglecting pressure effects and chemical reactions in solution causes most of the published codes to fail in the field. Our codes (VESCAL series) use a totally different, more practical approach. The first code of this series (VESCAL II, see Figures 3 and 4) will soon be described in a publication.¹⁸³ Preliminary laboratory and field tests have indicated that this new model is able to predict scale in oilfield and geothermal operations. It is suggested to test an entire series of recently developed new codes in a new set of field and laboratory experiments.

The greatest advantage of these codes in a building block system is that only the relevant portions of the model have to be run for a particular field application. This is contrary to other codes¹⁷⁸ which are too rigid to be changed, have no flexibility as far as field applications are concerned and are too time-consuming to run. Another advantage of these newly developed codes is that they can also be combined with reservoir simulators as shown in Figures 5 and 6. This will become extremely important if scale formation due to reinjection is expected anywhere in the reservoir. The "scale prediction" model alone cannot predict the detrimental effects of scale formation on the field operations in general and the reservoir management in particular. This combined "scale-reservoir" model will become critical for geothermal operations if imported make-up water has to be injected (see later in this report). The other codes mentioned above are too complicated to be combined with any type of reservoir simulator.

6.1.3 Particle Formation and Suspended Particles Caused by Brine Instability.

Suspended particles are the single most important cause of a decrease or loss of injectivity in geothermal operations. In this paragraph, we are not concerned with every type of suspended particles encountered in a geothermal injection system (see Section 7.1 in this report) but only with suspended particles formed by precipitation reactions. These particles are unique for geothermal operations and have caused considerable confusion and great difficulties in the attempted "technology transfer" of the oilfield brine treatment technology into geothermal fields. Oilfield brines are cooler than geothermal brines and the critical change of the thermodynamic conditions leading to particle formation is generally less severe in oilfield operations than in geothermal fields. In addition, the flow and injection rates of brines in oilfields are normally much smaller than in geothermal operations. Due to these extremely large injection rates in geothermal operations, more pronounced effects caused by particles per unit time are encountered in geothermal fields compared to those experienced in oilfields. This accelerated formation of suspended particles due to the brine instability can generate injection problems in geothermal operations which are unknown in oilfields.

The technical problems encountered in geothermal injection systems and related to precipitated and precipitating particles suspended in the brines are manifold:

1) Measuring of particle properties such as size, size distribution, consistency, shape, population, etc., is extremely difficult. All these particle parameters may change constantly, which poses severe problems for most measuring techniques (see later in this report). On the other hand, these parameters and their change as a function of time must be known if procedures for combating the particle problems are to be designed in an orderly fashion.

2) Removal of these particles offers great technical problems due to the fact that new and different particles are constantly formed as the thermodynamic conditions keep changing. Even without a constant change of these critical thermodynamic parameters, new precipitations (and with that, new particles) can constantly form due to "delayed" precipitation reactions (reaction kinetics). A common mistake is to attempt the removal of the suspended particles before the precipitation reactions come to a halt or at least slow down to a tolerable rate.

3) The huge mass of these particles if separated from the brine can create large disposal problems. Larger injection systems equivalent to hundreds of MW power production, can yield tens and hundreds of tons of solid waste per day. The solid waste problems dictate a thorough knowledge of all parameters leading to particle formation due to brine instability.

6.2 Gas Problems ("Non-Condensables")

In a recent SPE paper¹⁸ and a series of reports¹⁸⁴ to DOE/DGE we described a number of problems regarding the so-called "non-condensables". It leads beyond the frame of this present report to outline the serious problems concerned with the analytical determinations^{184,185} of all the so-called "non-condensables".

What seems to be important is the chemical and physical behavior of all gases in geothermal operations. The previous publications^{18,184} deal with calculating the CO₂ and N₂ behavior in some East Mesa (California) geothermal brines as a function of temperature, pressure and brine composition. It could be shown that a number of parameters and variables considered to be important have little or no effect on the gas behavior in a geothermal system. On the other hand, other parameters mostly ignored in previous codes and calculations have an extremely large effect on the solubility of the gases in a brine and on the properties of the brine itself.

Unfortunately, this model work was not extended to brines in other geothermal areas and to gases other than CO₂ and N₂. The model described

in the previous papers^{18,184} (see Figures 7 to 12) could easily be extended to other gases such as CH_4 and H_2S and to brines having a larger ionic strength and a more complicated chemical composition than the East Mesa brine. This extended work will be required for attacking and solving the problems outlined below.

6.2.1 Gas Venting

When a geothermal brine is produced, some of the dissolved gases may break out of solution. This not only generates some major problems regarding the brine characteristics and with that, the formation of scale and suspended particles, it also causes gas handling problems. Brine utilization and reinjection of a fluid cannot be separated. The gases breaking out of solution must be handled in a technically and economically feasible way. In previous papers^{18,184} we suggested that the possibility of a special gas venting process be investigated. This process seems to have an excellent potential for handling a number of brine utilization and reinjection problems (see Figures 11 and 12).

Proper modeling of the gas behavior (see above) suggested venting the gases into a special vent line before the brine/gas mixture (single or two phase systems) enters the power plant. The pressures and temperatures of the actual vent tank are critical in order to avoid venting of steam into this vent line. Venting the gases will prevent handling problems in the power plant itself. This is critical in steam cycle systems. The load of the gases on the steam ejectors or vacuum pumps downstream of the turbines can cause severe operating problems in the power plant. In addition, allowing the gases to pass through the turbines will decrease the power plant efficiency and economics by requiring extra energy for the downstream gas removal. For example, the highly expensive vacuum pumps must be oversized to handle the additional gas load. The vent line will by-pass the power plant, thus resulting in substantial savings for power plant construction and operations. However, this vent process can also cause some potential problems. The main question is: should this vented gas be released into the atmosphere or should it be reinjected together with the heat-depleted brine.

6.2.2 Injectability Problems by Gas Venting Into the Atmosphere

One set of problems regarding the releasing of any gas into the atmosphere is related to the injectability of the brine depleted in gas and heat. The chemical and physical properties of the gas and heat depleted brine can be quite different from those properties of the reservoir brine. For example, the pH of the reinjected brine could be on the order of 8.0 or even 9.0, whereas that of the reservoir brine could be on the order of 6.0. This means, the reinjected brine is now chemically incompatible with the reservoir brine. These compatibility problems could be overcome if the vented gases are recombined with the heat-depleted brine and reinjected into the reservoir. The technicalities of recombining

the gas and brine must be handled very carefully to avoid a power plant efficiency decrease by using processes which consume excessive amounts of energy. Presently, it is believed that this recombination could be achieved in an economically feasible way even though some thorough research efforts are required.

Another benefit from this gas/brine recombination process would be the avoidance of some environmental problems caused by venting gases into the environment. We are not concerned with emission problems caused by releasing CO_2 and N_2 into the atmosphere, but harmful gases such as H_2S are our main concern.

An additional aspect of this process is the possibility of a commercial exploitation of the gases instead of reinjection.

Neither one of the above-mentioned problems and possible solutions can be intelligently pursued unless the entire gas problem is evaluated in much more depth than done in the past.

6.2.3 Injectivity Problems by Gas Venting Into the Brine Injection Systems

The gas behavior causes not only brine stability, injectability and environmental problems as mentioned above, it can also generate serious injectivity problems. If the gas is reinjected without a complete dissolution in the reinjected brine, gas channels can form in the reservoir. The mobility of gas is larger by an order of magnitude than the mobility of the reservoir brine. The result could be "fingering" of the gas through the brine. Assuming the reservoir is non-isotropic, i.e., contains heterogeneities (high permeability streaks), the gas could break through in a comparatively short time. This would have a detrimental effect on the entire lifetime of a geothermal reservoir. Here again, any considerations remain speculative unless new research efforts are made. Therefore, it is suggested to investigate the gas behavior and related aspects in its entirety.

7.0 INJECTIVITY LOSS DURING REGULAR PRODUCTION AND INJECTION OPERATIONS

Injectivity losses with time can be expected in routine geothermal operations unless a number of factors are considered. The thermodynamic instability and related scale, particle and gas problems are only a part of the entire set of these factors. Other factors leading to an injectivity loss are related to other specifics of geothermal operations such as suspended particles other than those formed by the thermodynamic instability, corrosion, bacterial action, use of required chemical additives, etc.

Unfortunately, all these factors must be considered in a "package" because of the many interrelations between the individual factors. For example, it does not seem feasible to remove suspended particles

caused by the thermodynamic brine instability without also removing the suspended particles stemming from other causes. Therefore, it will be necessary to reconsider some of the previously-outlined problems in the following paragraphs.

7.1 Suspended Particles

As mentioned before, the most obvious damage in present geothermal injection wells is caused by suspended particles. They deserve our full attention in any major research effort regarding the solution of the problems encountered and to be expected in geothermal operations.

These particles suspended in geothermal brines can be categorized in various ways by common parameters such as:

- 1) Origin
- 2) Degree and/or type of damaging effects
- 3) Chemical composition
- 4) Physical parameters such as size, shape, consistency, etc.

7.1.1 Origin of Suspended Particles

The categorization preferred by the authors is by origin:

1) Particles generated through precipitation reactions in the flowing brines. The precipitation reactions are caused by the drastic changes of the thermodynamic conditions as mentioned previously in Section 6.0 of this report. Typical examples are silica, silicates, heavy metal sulfides and calcium carbonate.

2) Particles native to the producing reservoir and transported into the injection system by the flowing brine. Typical examples are sand grains and clay particles.

3) Particles formed through mixing of incompatible water with the injected brine. These particles are also formed by precipitation reactions as those described above and, therefore, are also dependent upon the thermodynamic conditions. However, these particles are not formed because of simple pressure and/or temperature changes. Typical examples are alkaline earth metal sulfates and carbonates.

4) Particles generated by undesired precipitation reactions caused through addition of chemical additives to the brine or through chemical brine alteration. Typical examples are the calcium and iron salts of scale inhibitors (e.g., calcium phosphonates and polyacrylates), calcium fluorides and basic "alkaline scale" particles (e.g., magnesium hydroxide).

5) Particles caused by various types of corrosion. Typical examples are iron sulfides and hydroxides.

6) Particles caused by oxygen contamination. Typical examples are iron oxides (hydroxides and oxy-hydrates) and elemental sulfur.

7) Particles formed through bacterial reactions. Typical examples are slimes.

8) Particles consisting of dislodged formation material caused by temperature and mechanical stresses. Typical examples are clay particles.

9) Particles caused by a lack of cleanliness such as dirty pipelines and power plant components, mud and dirt in tankers, containers and other work-over equipment. Typical examples are dirt and mud particles.

10) Particles caused by a lack or inefficiency of clean-up after drilling and completion of producing wells. Typical examples are mud fines, formation cuttings and break-down products of drilling and completion fluid additives.

7.1.2 Measurement and Monitoring of Suspended Particles

The effects of these suspended particles on geothermal operations must be evaluated. It is self-understood that any technical evaluation either to determine the effects of these particles on field operations or to manipulate these particles in the brine must start with the correct measurements and monitoring of all suspended material.

Table II lists some critical particle properties which can be used to predict damage caused by particles suspended in geothermal brines. Correct monitoring of these particles could be accomplished by determining these properties in the flowing brine. Any removal of particles to prevent damage in the field must take into account these critical properties.

Measurement of the various particle properties in a flowing geothermal brine is extremely difficult. Presently, no adequate methodology for the required in-situ and instantaneous determination of particle properties in these brines is available. Only instantaneous and in-situ measurements, i.e., determination of all critical particle properties in the flowing brine offer a chance to obtain the data required for a thorough understanding of the particle formation and behavior. These parameters must be determined before starting a well-designed research program aimed at solving the operational problems caused by suspended particles.

Previous experiments regarding the measurements of particle properties relied heavily on "measuring" these properties in samples drawn from the flowing brine. Millipore filter tests,¹⁴⁻¹⁷ coulter counters and fixed angle light scattering devices were used for these "measurements".

There are many reasons for the failure of these commonly accepted methods to yield exact data on the critical particle parameters:

1) It is nearly impossible to draw a representative sample from a flowing line, vessel or other components of a geothermal installation. The suspended particles must be very evenly distributed in the sampled fluid and the sample port must be constructed in such a way that the particles (evenly distributed in the flowing brine) can be withdrawn without changing this distribution. Either one of these two requirements, even distribution and maintaining this distribution in the withdrawn sample, are almost impossible to meet.

2) The particle properties will change as a function of thermodynamic conditions and time. This fact leads to an entire set of complicated problems.

First of all, it is extremely difficult to draw a sample from any sampling port without changing the thermodynamic conditions. The sample drawn from the brine flow system is under a different set of thermodynamic conditions, particularly pressure and temperature, than the sampled fluid within the geothermal system. Therefore, most particle properties are drastically changed during the process of sampling. For example, millipore filter tests frequently used or recommended for geothermal injection operations¹⁴⁻¹⁷ are fully adequate for most oilfield operations but should not be used in geothermal injection systems. The pressure and temperature drops in the sample lines and across the millipore filter will actually generate new particles and may alter the thermodynamic conditions upstream of the test equipment. Thus, the millipore test will show particle "properties" absolutely different from those encountered in the geothermal brine system upstream of the filter. This discrepancy between actual and "measured" particle properties becomes especially large and intolerable in the case of amorphous silica particles.

The silica particles generated on or within the filter can be very large because of the immobile water layers on the initially precipitated amorphous silica. Rapid plugging of the filter with these particles causes larger pressure and temperature drops across the filter, thus causing a "snow-ball" or "self-aggravating" effect. This effect is larger the more silica is dissolved in the brine, i.e., brines produced from high temperature reservoirs exhibit a larger filter plugging tendency than brines produced from low temperature reservoirs. Attempted millipore filter tests in various high temperature brines, (Valle Caldera, Niland, Brawley, unpublished data) were unsuccessful. Selecting filters with large pore size did not allow effective filtering (particle flow through the filter). Choosing the filters with successively smaller pore size resulted in rapid plugging of the filters.

The use of Coulter counters or sintered metal filters (see Figure 13) were equally unsuccessful for reasons outlined above. Sintered metal

filters in a special arrangement (see Figure 14) seem to offer the best chance for keeping the pressure and temperature drops between sample and sampled fluid at a minimum, thus yielding the better, i.e., more reliable, data on the particle properties. These filters can even be arranged within the flowing brine (see Figure 15), thus giving minimum temperature drops during particle determinations through filtering. This latter arrangement requires a shut-down or a special bypass loop to examine or replace the filters.

Another common mistake is to collect particles on a filter and then to "determine" various particle properties after storing or even drying of the filtered particle. It should be self-understood that the stored or dried particles are considerably altered during the storage or drying periods. For example, freshly precipitated silica will polymerize, i.e., an originally precipitated low molecular solid loses much of its water and becomes a very hard solid. This polymerization is also accompanied by a shrinking process. As a result, the solids collected on the millipore filter will change many of their original properties during the storage and drying periods. Thus, most data collected this way become irrelevant for any evaluation work of the geothermal injection processes.

Another frequently made attempt is the use of fixed angle light scattering devices for measuring particle properties. Even monochromatic laser beam scattering cannot overcome most of the problems encountered in particle measurements.

Most of these methods rely on the intensity measurement of the light scattered under a fixed angle (normally 90°) to the incoming light beam of known intensity. Unfortunately, the intensity of the scattered monochromatic light depends on quite a number of parameters:

- 1) Particle size
- 2) Particle size distribution
- 3) Particle shape
- 4) Particle population
- 5) Refractive index of fluid
- 6) Refractive index of solid

However, only one measurement is made, namely the determination of the scattered light intensity at the fixed angle, whereas, at least six (6) different and independent parameters contribute independently to this measured value. It should be obvious that a single measured value cannot be used to determine six (6) independent and different parameters!

Summarizing, we can safely state that commonly used measurements of the extremely critical particle properties are inadequate. The combination "sampling-measuring" leads to erroneous and misleading data which should be discarded. Only instantaneous, in-situ measurements of the particle properties should be considered. These data are needed for the suggested work outlined in later paragraphs.

7.1.3 Injector Lifetime Predictions Based on Particle Measurements

The operator of a geothermal field would like to predict injection problems before these problems actually occur in the field. These precise prediction methods would have considerable advantages in geothermal operations:

1. Costly damage of injectors and injection reservoirs could be prevented before occurring. This would not only prevent costly work-overs but also irreparable reservoir damage during extended periods of injection.
2. Various types of brine treatment and injection methods could be evaluated on the basis of these prediction methods without the need of costly "trial and error" methods in the field.
3. In addition, these predictions would allow us to evaluate the various brine treatment and injection methods on a cost-performance basis with a minimum of costly field experiments.

At least theoretically, a knowledge of all particle properties listed in Table 2 would be a critical step toward successful damage prediction and process evaluations.

7.1.3.1 Particle Movement in Porous Medium

The problem of particle movements in porous medium is well recognized and many publications¹⁸⁸⁻¹⁹² deal with this problem. However, it is our opinion that this problem, even though critical for many industrial operations, is not very well understood and deserves further attention. Not only are the critical particle qualities difficult to measure, the relations between the various particle parameters and the geometry of the porous medium itself are still very obscure. As a matter of fact, it is nearly impossible to describe the structure of a porous medium, not to speak of the relations between the structure of the particles and that of the porous medium. On the other hand, the invasion of the particles into the reservoir and their movement within the formation is of vital importance for the brine injectivity. Therefore, the problems of particle invasion and movement needs a strong research effort. This topic cannot be overemphasized and will be treated in more detail in later sections of this report.

7.1.3.2 Barkman-Davidson Method and its Limitations

Barkman and Davidson described in their original paper¹⁸⁶ a rather ingenious way to predict injection problems caused by suspended particles. This method is based on millipore filter tests. Four different mechanisms of wellbore and reservoir damage by particles are described:

- 1) Fill-up of the wellbore
- 2) Formation of a filter cake on the sandface
- 3) Particle invasion of the reservoir and formation of damage collars.
- 4) Plugging of perforation holes

Unfortunately, the method described in the original paper suffers from a number of shortcomings and limitations. The behavior of a cake formed by particles on a millipore filter is not necessarily related to the behavior of particles forming a cake in the wellbore or penetrating the reservoir and forming damage collars. The reasons seem to be rather obvious. Some short-comings of the filter test itself were outlined in previous paragraphs. However, even if the particle properties would be correctly measured, the method still would not be very reliable for a number of additional reasons:

- 1) The water must enter the reservoir uniformly. The injectivity must be the same over the entire injection profile. Hardly any well will exhibit this profile. If fractures extend into the wellbore, the method is not useable at all.

- 2) The surface of the filter and the sandface of the injection internal must receive the same type and number of solids per unit volume of injected liquid. "Proper" drawing of a representative fluid sample for the filter is nearly impossible.¹⁸⁷ For example, if more solids (e.g., clay particles or heavy metal sulfides) are flowing in the lower half of an injection water line but the liquid from the upper half of the same line is examined through the filter, erroneous data will result: the coverage of equal areas on the filter and on the sandface will be different. Riley¹⁸⁷ showed through isokinetic sampling that this danger is real in many geothermal brine lines.

- 3) The permeability of the filter cake must be the same as that of the cake inside the wellbore. Experiments in the laboratory and sandpack flow tests ("thick cake") have shown that the packing of the particles in the cake is pressure dependent, i.e., the arrangements of particles and particle aggregates dependent upon pressure profiles. For example, a low pressure applied across the filter cake will result in a different cake permeability than that resulting from the higher

pressure in the wellbore. The pressures across the millipore filter cake can be quite different than those across the wellbore cake, thus yielding two different permeabilities and erroneous results.

4) The particle arrangement on any filter cake is also flow rate dependent. Here again, different conditions on the filter and on the sandface will lead to erroneous data.

5) The filter cake in the wellbore must not have any fractures at all, which cannot be guaranteed.

6) The suspended particles in the water cannot be smaller than the filter pores and larger than the pore throats in the reservoir rock. The true pore throat size in the reservoir is generally not known, thus making it nearly impossible to predict particle invasion and the extent and location of damage collars.

7) Water injection must never be interrupted because stoppage or even back-flow may cause rearrangement of the particles in the cake. Changes of the pressure drop across any cake may cause particle rearrangements in the cake.

8) Variations of the particle geometry and formation permeability as found in many wells can cause the simultaneous occurrence of the various damaging mechanisms. For example, all the particles may form a cake at one interval, whereas, some particles may penetrate into the reservoir at another interval, thus possibly causing formation damage after reservoir penetration. Another kind of mixed behavior is also conceivable: all particles retained on the millipore filter will form a cake having a certain cake permeability (depending on the many factors), whereas, many of these particles in an actual well may sink to the bottom (wellbore fill-up), thus resulting in permeability of the wellbore cake totally different from that found and measured in the millipore filter cake.

9) Any mixed behavior will result in wrong predictions. "Deep bed invasion" or forming of damage collars can be predicted only in a very qualitative way unless the radii of the collars can be calculated from filter test data. No such calculation or prediction have been described in the open literature. Therefore "predicting" of damage collars is presently rather vague and meaningless.

10) The slope of the curve "cumulative volume vs. square root of time" may change after an extended millipore filter time. The second slope is more important than the initial slope. There may always be uncertainties after a given filtering period as to the proper slope determination. This is particularly true in fluids containing colloidal material such as amorphous silica. Geothermal brines are notorious for silica precipitations.

It is self-explanatory that all the basic limitations of the Barkman-Davidson method mentioned above hold also true in geothermal injection brine. However, typical geothermal brines offer additional restrictions for the usefulness of the method:

1) The thermodynamic instability of geothermal brines offer additional problems. Precipitations can easily occur downstream of the sample port for the millipore filter, thus yielding quite erroneous predictions. Silica especially is notorious for "delayed" or "after" precipitations (kinetics). In these cases, more particles will form downstream of the filter station, thus predicting longer injector half-lifetimes than experienced in the field.

2) The pressure and temperature drops across the filter cake and the filter itself can cause additional types of precipitations, i.e., more and different particles are found within the filter than in the well. This will result in pessimistic lifetime predictions.

3) Cementing of the materials may occur in the wellbore but not on the millipore filter. This will cause the opposite effect of that described above. This phenomena can be frequently observed in geothermal wells. The colloidal silica particles will "bind" the formerly loose suspended particles over longer injection periods. Unfortunately, this cementing occurs within the cake inside the wellbore. Bailed samples of the wellbore cake and fill-up often do not resemble loose particles but cemented rock with almost no permeability. The wellbore cake may be only a fraction of an inch thick but will decrease the injectivity to intolerable levels. In these cases, (and they are the over-riding majority!) the millipore filter test will yield too optimistic "data" because it does not simulate these time-dependent (long-term) reactions.

4) Quite often ductile particles are suspended and/or formed in the injected brine. The silica particles are especially prone in this regard. These particles will penetrate into the millipore filter without passing through. This ductility is also pressure and time dependent. These particles may plug the filter but not the sandface. Some geothermal brines cannot be filtered with the millipore filter, i.e., the predicted half-lifetimes are zero, whereas, the well may take the fluids for extended periods of time. One of the authors of this report has had extremely bad experiences in this regard in some geothermal wells in New Mexico.

Any combination of the above-mentioned effects may occur simultaneously, thus rendering the Barkman-Davidson method totally unreliable in geothermal operations. The injection well performance predicted from millipore filter tests is in almost all cases quite different from the well performance experienced in the field. Some "correct" predictions may be explained by the fact that the errors leading to pessimistic and optimistic predictions may cancel by accident.

7.1.3.3 Improved Barkman-Davidson Method

Lawrence Livermore Laboratories is well aware of most of these limitations. Various improvements have been suggested:

- 1) Replace the filter with actual cores to count for the difference in the pore geometry of the filter itself and that of the reservoir material.

- 2) Use of an "incubation cell" to account for some effects of the thermodynamic instability of geothermal brines. A sample of the injection brine is tested through a core by using a "load cell" which by itself is an improvement of the experimental set-up. This "load cell" will keep pressure and temperature changes of the brine at a minimum. An aliquot of the sample is incubated under "in-line" conditions for an extended period of time and then tested again to account for the reaction kinetics which change the particle consistency and geometry in the wellbore.

This method, at least theoretically, could be incorporated into a test procedure that takes into account all the thermodynamic and kinetic factors that make the Barkman-Davidson method in its original form so unreliable for geothermal operations. This method would represent an improvement toward establishing a better relationship between the thermodynamic and kinetic brine conditions in the wellbore and the data obtained with a filter apparatus. However, even this improved method cannot overcome problems caused by the hydrodynamic conditions (flow profiles) within the wellbore and many of the basic short-comings of the Barkman-Davidson method mentioned earlier. A different approach is suggested in later paragraphs of this report.

7.2 Corrosion Problems

Geothermal brines may be rather corrosive. Some work on the subject is presently being performed by Battelle PNL and Lawrence Livermore Laboratory. The "regular" corrosion effects can be handled by either using special low price alloys for injection well equipment or by adding common inhibitors to the reinjected brine.

The use of inhibitors is more or less common oilfield technology which can find its application in geothermal reinjection systems provided the temperature of the reinjected brine is not excessively high (more than 100°C). Caution must be exercised that

- 1) addition of the inhibitor remains economically feasible,
- 2) inhibitor injection will not cause any undesired precipitation reactions with the brine components, and

- 3) plating (or adsorption) of the inhibitor components on the rock within the porous medium will not cause any change of the wettability (contact angle) of the rock and with that a decrease of the injectivity.

Corrosion inhibition in injection equipment is not considered a critical item for a major research effort to be funded by DOE/DGE even though it may be of interest to investigate the effects of several effective inhibitors on the injectivity of some cores retrieved from geothermal reinjection wells.

Corrosion rates in geothermal reinjection systems may skyrocket if oxygen contamination of the brines is permitted. Some reports of excessive corrosion rates in injection wells cannot be taken without reservations unless precise oxygen measurements in the brines are performed together with the corrosion rate determinations. Recent test work in the Imperial Valley by one of the authors showed that traces of oxygen sufficient to boost the corrosion rates are frequently found in geothermal injection systems. Any future field testing should include oxygen measurements in the reinjected brine and an attempt to find the sources for this possible oxygen contamination.

7.3 Bacterial Action

It is also conceivable that bacterial slimes and other life matter can seriously impair the reinjection in geothermal operations. However, it does not seem to be conceivable that this life matter (or remnants thereof) can originate in a geothermal producing reservoir. Here again, contamination of the brine with foreign matter in surface operations can lead to this problem. The operator must exercise extreme caution to prevent contamination of his reinjection brine in order to avoid the problems generated by bacterial action.

8.0 INJECTIVITY LOSS CAUSED BY MEASURES OTHER THAN REGULAR OPERATIONS

Injection problems can also occur during drilling, completing and working over of injection and production wells in geothermal operations.

Injectivity impairment can be experienced during the drilling, completion and/or work-over operations of reinjection wells. An additional loss of injectivity can also be expected during and after drilling, completing or stimulation of production wells. The disposal of various fluids during or after these operations into the stream of brine or directly into a reinjection well are common practice and can lead to severe injectivity problems. Some drilling, completion and/or stimulation fluids from producing wells can cause serious and lasting wellbore and formation damage in the reinjection wells. Unfortunately, environmental regulations require this use of injection wells as disposal wells during drilling, completion and/or work-over operations in any production or injection well.

8.1 Damage Caused by Drilling and Completion of Injection Wells

If the injection wells are completed in the hot geothermal reservoir (see later in this report), drilling and completion procedures may cause severe damage.¹⁹³⁻¹⁹⁷ A major research program funded by DOE/DGE is presently underway to study drilling and completion techniques in high temperature geothermal operations. It is felt that any detailed treatment of the subject in this present report would lead to superfluous information and is, therefore, omitted.

8.2 Damage Through Work-Over of Injection Wells

The open literature on stimulation methods of geothermal injection wells is extremely limited. It can safely be assumed that the damage to be removed from geothermal injection wells is different from that experienced in injection wells in oil or gas operations. The brine reinjected into geothermal injection wells originated in a producing reservoir which has generally a much higher temperature than most oil or gas producing reservoirs. Therefore, the chemical composition of the fluids and suspended particles in geothermal brines is unique for geothermal operations and needs a unique treatment.

Experimental stimulations of geothermal injection wells may require acids¹⁹⁸ or other fluids such as chelating agents or high pH liquids to attack the material which causes the main damage. All of these fluids may not only show beneficial effects, e.g., the dissolution of silica in mud acid (HF)¹⁹⁸, but may also show detrimental effects, e.g., the formation of solid calcium fluoride and cryolites. Some recently attempted mud acid stimulations (unpublished results) showed that over 90% of the injected HF did not return from a geothermal well, whereas almost all of the simultaneously injected HCl and most mud acid additives were found in the "spent" fluid. These recent field experiments suggest that the reaction products of high temperature stimulation jobs are not well known and can lead to severe formation damage.

A DOE/DGE funded research project on stimulation of producing wells is under way. In the course of this work, we will make some serious attempts to identify the undesired side reactions encountered in high temperature well stimulations and much of this work will also be applicable to geothermal injection wells. However, some of the injection wellbore damage, particularly the deposition of silica and heavy metal sulfides is quite different from the production wellbore damage. In addition, the formation and location of a skin in a geothermal producing well is different from that in a geothermal injection well. Therefore, additional work is required to study the formation of secondary wellbore damage during an attempted stimulation of geothermal injection wells.

8.3 Damage Through Work-Over of Production Wells

Any chemical stimulation of production wells may endanger the injection wells when the spent fluids from the stimulation job enter the reinjection system. Not only a new type of suspended particles will enter the reinjection system, but the entire chemistry of the heat-depleted brine may occur. The spent fluids from the work-over, e.g., an acid job, may be saturated at a fairly low pH with dissolved material. Dispersing of these saturated low pH fluids in the high pH injection brine may cause new precipitations in the injection system.

Using HCl and HCl/HF mixtures in some recent wellbore stimulations (unpublished results) caused some severe problems in the injection brine. The partially spent fluids reacted with some solid materials deposited in the injection line, removed the cementing CaCO_3 in the scale and caused an excessive concentration of suspended solids in the reinjected brine.

In addition, any equipment used for brine quality control (e.g., filters, settling tanks, clarifiers, etc.) may become unbalanced through the spent stimulation fluids. The intermittent and excessive load of solids during these jobs may overload the equipment. The chemicals used in aiding the removal of suspended solids may become ineffective in the new environment containing spent stimulation fluids. Thus, the solid removing processes effectively used during routine operations may become ineffective. This, in turn, will lead to damage in the injection wells.

8.4 Damage Through Chemical Additives Used During Routine Operations

Chemical additives used in or suggested for routine geothermal operations may show various undesired side effects leading to injection problems. For example, a highly effective scale inhibitor required to maintain a scale-free power plant may exhibit an undesired "efficiency-time" relation¹⁹⁹ (see Figure 16). The scale will not form in the power plant or any other surface equipment. However, the precipitations may still occur and solid particles will be formed. These fine particles may now pass through filters and can lead to serious injection well impairment. This type of reaction was experienced in some recent field experiments and deserves further attention.

There are two basic types of undesired side reactions to be expected when chemical additives are used:

- 1) Reactions between additives and brine components.
- 2) Reactions between different types of additives.

For example, scale inhibitors may prevent the formation of scale, but they may also form highly insoluble calcium, magnesium or iron salts

by themselves.²⁰⁰ These pseudo-scales may be more damaging to the injection wells than the original scale itself.

Another example is the interaction between a scale inhibitor and a flocculant. Both chemicals may react with each other, thus leading to ineffective scale inhibition and flocculation.

It is suggested to study these side reactions of chemical additives with brine components or with each other in future research projects.

9.0 HEAT MINING AND ASSOCIATED RESERVOIR PROBLEMS IN REINJECTION

In the long term, the reinjection of geothermal fluids into the formation is a necessary prerequisite in maintaining a viable geothermal industry. The benefits of reinjection have already been enumerated earlier in this report. However, there are significant problems which develop as a result of this reinjection process which must be predicted and contingency plans and/or changes in operational strategies must be made to prevent these problems from reaching critical proportions.

The types of problems that we allude to can develop in the wellbore and in the reservoir regions. In the wellbore region, the problems are localized in nature. They usually develop rapidly and can sometimes be solved in a routine, though expensive, manner. For example, a final solution to a particularly intractable wellbore problem could be to plug and abandon and drill another well. In the reservoir the problems are larger; they usually do not develop as rapidly as those in the wellbore and their outcome affects the whole reservoir life-cycle. These latter problems are collectively those associated with heat mining and problems which develop that are caused by inappropriate or ill-conceived design procedures in locating and operating the injectors. The overall thrust, as in any project, geothermal or otherwise, is to optimize the total energy output (\$\$) of the system; and this involves a judicious balance between the heat removal in the power plant, the cooling of the reservoir by cold water injection and the pressure maintenance of the geothermal reservoir by fluid injection.

In this section we wish to identify and define those problems which are germane to heat mining and discuss these within the context of the wellbore and the reservoir regions only.

9.1 Wellbore Considerations

The wellbore is our only link with the geothermal reservoir. All fluid must enter or leave through this single opening. It behooves us to know as much as possible and to be able to predict what is occurring in the wellbore during the reinjection process.

The chief problems which can occur in the wellbore are related to hydrodynamic and thermodynamic changes in the fluids and their compositions; these are caused by pressure, volume and temperature related variations which occur in the flow and also by the residence time of the fluid in the wellbore. It has been pointed out earlier that thermodynamic changes in the brine can lead to stability problems of the ions which could precipitate or create suspended particles in the flowing fluids.

A significant problem is to accurately predict the thermodynamic behavior of the fluids as they traverse the wellbore.

Ramey²⁰¹ and others²⁰²⁻²⁰⁵ have looked at the flow problem of hot fluids in wellbores. Their approach was basically to model the heat-loss term to the earth and then recalculate the pressure-temperature profile for the flowing fluid within the wellbore. Their work has been limited to steam or hot water injection into petroleum reservoirs. In our type of geothermal environment, there are two fundamental differences which lead to problems completely unheard of in the oil industry. First, the difference in volumes of fluids produced; typically, we are dealing with millions of pounds per day of geothermal fluids while in the petroleum industry, we generally consider thousands of pounds of fluids. Secondly and more importantly, the geothermal fluid is a high temperature brine which contains several ionic species which can create severe problems because of their thermodynamic response to changes in pressure and temperature. These salts can cause the formation of suspended particles, and by modeling the wellbore system, we can determine a priori under what flow conditions these problems will develop.

Gould²⁰³ has looked at two-phase flow of steam-water mixtures in geothermal wells in which he considered gas and liquid flow separately. Upadhyaya²⁰⁶ et al. have tried to match observed pressure drop in steam-water geothermal wells with varying degrees of success. Tansev²⁰⁷ et al. have used a similar technique to model vertical flow of geothermal wellbores. Toronyi²⁰⁸ and Farouq Ali have modeled the wellbore flow assuming the steam-water mixture is a homogeneous mixture. Their frictional pressure drop was correlated using two-phase multipliers as described by Martinelli-Nelson.

All current techniques for modeling wellbore hydraulics and temperature behavior use a coupled pressure loss-heat transfer computational procedure which assumes steady-state flow conditions. The basic equation which relates pressure drop to vertical height is described below:

$$\frac{dP}{dL} = - \underbrace{\bar{\rho} \frac{g}{g_c} \cos \theta}_{\text{gravity term}} - \underbrace{\frac{f_m \rho v_T^2}{2 g_c d}}_{\text{frictional term}} - \underbrace{\bar{\rho} \frac{v_T}{g_c} \frac{dv_T}{dL}}_{\text{acceleration term}}$$

In the equation the following are defined:

- P = pressure (psi)
- L = length (feet)
- $\bar{\rho}$ = average mixture density (lb_m/ft³)
- g = gravitational acceleration (ft/sec²)
- θ = wellbore angle
- f_m = moody friction factor
- ρ_r = correlated density of given mixture
- v_T = total velocity (ft/sec)
- d = ID of wellbore (feet)

The heat transfer model is described as follows:

$$\Delta H_i = \underset{\substack{\uparrow \\ \text{heat} \\ \text{loss} \\ \text{term}}}{-Q} + \underset{\substack{\uparrow \\ \text{potential} \\ \text{energy} \\ \text{term}}}{\frac{g}{g_c} \frac{\Delta z}{J}} + \underset{\substack{\uparrow \\ \text{kinetic} \\ \text{energy} \\ \text{term}}}{\frac{\Delta v_T^2}{2 g_c J}}$$

where the new variables are:

Δ H_i = change in enthalpy over the interval "i" (Btu/lb_m)

Q = heat conduction to earth (Btu/lb_m)

Δ z = elevation term (ft)

J = mechanical equivalent of heat (778 ft-lb_f/Btu)

A significant number of correlations are needed to properly calculate each of the terms in the pressure and heat equations. These correlations are, for the most part, empirical and have been transferred directly from the two-phase petroleum literature. There has been good to reasonable agreement between the calculated pressure profiles and those observed in the field. The temperature drop in the wellbore is usually very small because of the very high flow rates and consequently, the flow can be considered almost isothermal.

The stability of the brines is an important problem which until now has not been incorporated into geothermal wellbore predictions. This has been expected since hither to this time more emphasis has been placed on the production phase rather than the reinjection phase of operations. Our work has indicated that we must include an additional module into the overall modeling of wellbore behavior in geothermal systems - we must include the thermodynamic behavior of the ionic species which are present in the system. The proposed Vetter-PTTS model compared to the existing models is shown in Figure 17.

All three elements of the fluid behavior must be accounted for inter-dependently to predict fluid and particle behavior during the reinjection phase.

The thermodynamic behavior of the flow system, i.e., the precipitations as a function of thermodynamic conditions, can be modeled by utilizing already developed models. VESCAL II (see Figure 4)¹⁸³ could easily be adapted for this purpose. Another over-all model (see Figures 5, 6 and 30) could also be utilized for this type of computation.

In the existing literature, no coherent attempt has been made to couple the thermodynamics of brine alteration during flow with the flow mechanics of the fluid. This must be investigated in great detail since the success of reinjection is directly related to accurate, predictive means for flow parameters and thermodynamic stability of the brine such as salt precipitation.

There must be a coupling of the chemical modeling and the fluid dynamic modeling to allow the industry to keep abreast of technology as it is available today. The emphasis suggested by the authors of this Phase I study, is to use the available algorithms which have proven sufficiently capable of producing realistic data in the geothermal industry and extend these algorithms to provide for the new technologies which develop from the experimental and theoretical work in the second phase of this project.

9.2 Reservoir Considerations

In this definitive study, no attempt has been made to examine the simulation²⁰⁹⁻²¹⁴ of the behavior of the geothermal reservoir in an areal sense; i.e., we have not considered in detail the merits of the two-dimensional or three-dimensional models which look at total reservoir behavior using a finite element or finite difference grid. Instead, we are addressing specific problems which occur in the reservoir and attempting to define these and postulate methods which may lead to operational solutions. The specific problem types we consider are: reheating of the reservoir region; mixing of geothermal waters; hydraulic and thermal fronts. These problems can be more realistically appraised and analyzed by subjecting them to individual scrutiny rather than

lumping them together into a global model as is the case of a generalized geothermal reservoir simulator.

In defining the problems in reinjection of geothermal fluids, close attention must be paid to the near wellbore region of the reservoir. Let us consider this region in some detail.

9.2.1 Modeling Near-Wellbore Temperature Profiles

One area of considerable disagreement is the reheating of the reservoir rock by the thermal gradients when cold fluid is reinjected into the reservoir. Jorda¹⁴⁻¹⁷ and others hold that the prevailing reservoir temperatures and heat content is sufficient to reheat the geothermal zone and thereby redissolve any precipitated material in the wellbore region. This philosophy does not seem to be intuitively possible within realistic time scales and the need for analysis and clarification is a basic area of interest to the reporters of this study. In modeling the near-wellbore region - in this case, up to a few hundred feet radially from the injection point - we intend to examine the validity of these published claims, especially the concept of reheating and redissolution of the precipitated salts. The model necessary to analyze the system is discussed below.

Let us consider an injection well located in the center of a cylindrical region (reservoir). For simplicity, the total depth (TD) of the well is located at the injection zone and the height of overburden and underburden are z_1 and z_2 , respectively. These are illustrated in Figures 18 and 19, respectively.

Using the conservation laws²¹⁵ for heat and mass transfer in two dimensions, we can derive the following equation (1). This equation describes the temperature behavior in the near-wellbore region. Initial conditions are rather simple. The reservoir temperature is that expected from the existing geothermal gradient in the area.

$$\frac{1}{r} \frac{\delta}{\delta r} \left(kr \frac{\delta T}{\delta r} \right) + \frac{\delta}{\delta z} \left(k \frac{\delta T}{\delta z} \right) - \frac{5.615 (\rho c)_w}{2 \pi r} \frac{q_w}{\Delta z} \frac{\delta T}{\delta r} + Q_{fr} = (\rho c)_{eff} \frac{\delta T}{\delta t} \dots (1)$$

where: T = temperature (°F)

K = thermal conductivity (Btu/hr-ft-°F)

ρ = density (lb_m/ft³)

c = heat capacity (Btu/lb_m-°F)

t = time

z = vertical distance (ft)

r = radial dimension (ft)

q_w = injection flow rate (bbl/hr)

Q_{fr} = frictional heating rate (Btu/hr)

Subscripts:

eff = effective

w = water

Thus, $T(r,z,0) = F_0(z)$ (2)

where $F_0(z)$ is the geothermal temperature equation. Boundary Conditions are somewhat complicated at the inner boundary, i.e., wellbore side, but rather straightforward at the outer boundaries, i.e., the top and bottom and the extremities of the system. Figure 20 illustrates the boundary conditions necessary to complete the modeling of the reservoir. Essentially, the outer extremities of the system are either at a constant temperature or experience a temperature based on the geothermal gradient. The inner conditions existing at the wellbore reflect either a flowing condition, i.e., temperature dependent on the injected fluid, or a shut-in condition in which the radial temperature gradient is zero.

Solution of the near-wellbore temperature model

The interactions of the cold injected fluid and the hot reservoir rock produces a cooling effect. To understand this effect, we must produce temperature contours of the region around the wellbore. The type of contour map is shown in Figure 21.

Finite difference techniques are used to solve equation (1) over a grid network which is superimposed on the wellbore region. The details of this method are omitted from the definition study but form part of the proposal to DOE for Phase II of this study.

This near-wellbore model would provide us with a tool to examine the problems which occur early in the reinjection cycle; to examine cooling effects and to answer the questions of possible resaturation.

DOE has already funded several studies for modeling the heat and mass transfer in the geothermal system.²⁰⁹⁻²¹⁴ These codes are primarily without the chemical interface necessary to qualify the precipitation and dissolution reactions which occur during flow of reservoir fluids. These deficiencies must be overcome by addition and modification to

provide those key answers which will indicate the possible problem areas in the reservoir as reinjection progresses.

9.2.2 Modeling of Frontal Advances

A serious concern in geothermal reservoir engineering are the problems associated with reinjection of brine into the geothermal reservoir. Reinjection is necessary and provides the only sure way to solve the problem of disposal. Reinjection also helps maintain reservoir pressure, minimizes subsidence and allows the optimization of heat energy extraction in the power cycles. The problems arising out of reinjection stem from the cooling of the host rock by the reinjected water as the water moves from the injectors to the producers. Optimal heat recovery depends on suitable allocation of injection rates and injection well placement.

As the injected brine moves through the reservoir, there are two distinct frontal phenomena observed. There is the hydrodynamic front which is the physical interface between the native reservoir water and the reinjected water. This front is always ahead of the thermal front, as shown in Figure 22. The thermal front is that location where there is a discernible difference between the virgin temperature of the rock formation and the temperature of the cool reinjected water. As the cool fluid moves through the rock pore space, it absorbs heat, cools the rock and finally reaches a temperature equilibrium somewhere between the original rock temperature and the cold water level. This cooling effect is an unsteady-state process and the rate of cooling will depend on rock thermal properties, fluid thermal properties and on the velocity of flow through the pore space. Because of the heat transfer process, there is a temperature profile along the direction of flow rather than a step function temperature distribution; this transition which occurs produces the front which always lags behind the hydrodynamic front.

It is important that the location of these fronts as a function of time and flow rate be known. It is quite clear that when the cold water temperatures arrive at the producers, the reservoir life is over, since no more useable heat will be extracted in the power cycle.

Arrival of the hydrodynamic front is important because of mixing problems which may occur on account of different brine characteristics; these mixing problems are, however, not as critical as those created when the cold water front arrives at a point which is illustrated in the paper by Chin Fu Tsang⁶ et al.

9.2.2.1 Hydrodynamic Front by Steamline Approach

The hydrodynamic front corresponds to the mass of injected water. The flow mechanics are identical to those of a typical single-phase flow system in porous media and as such are governed by a diffusivity type equation.

$$\frac{\delta^2 P}{\delta x^2} + \frac{\delta^2 P}{\delta y^2} = \frac{\phi \mu c}{k} \frac{\delta P}{\delta t} \quad \dots \dots \dots (3)$$

where P = pressure

ϕ = porosity

μ = viscosity

k = permeability

x,y = coordinate distances

The hydrodynamic fronts move along fluid paths from the injection to the production wells under the existing pressure gradients. These fluid paths and their locations must be determined to define the hydrodynamic front locations. We can determine the flow paths by computing the streamline and stream tube locations in the reservoir. The streamlines are representations of the velocity components in the flow field. They, in essence, provide us with the direction and magnitude of the flow at any given location. The stream tube is a model consideration which allocates to a given streamline a "conduit" or channel in which all the fluid is travelling at the same velocity and in the same direction as that represented by the streamlines.

The locations of streamlines in porous media are calculated using information developed from the line-source and line-sink solutions of the diffusivity equations. Muskat,²¹⁶ Collins,²¹⁷ and others have described several approaches to solving this particular problem. In essence, the technique involves solving the diffusivity type equation, then by a superposition technique, the interacting effects of all the wells in the system are included. The boundary effects are included by a series of imaging techniques. The streamline is determined by modeling the velocity, then tracing the locus of these velocity vectors. The steady state pressure equation, shown here, is the starting point in developing the streamlines:

$$\frac{\delta^2 P}{\delta x^2} + \frac{\delta^2 P}{\delta y^2} = 0 \quad \dots \dots \dots (4)$$

The analytical solution is obtained in terms of pressure and this pressure is then differentiated to provide the gradients needed in the velocity equation:

$$V = - \frac{K}{\phi \mu} \frac{\delta P}{\delta x} \dots \dots \dots (5)$$

It can be shown in greater detail that the net result of this differentiation and superposition process is an equation which includes the effect of all wells in the system.

The final formula of the velocity equations is:

$$V_x = \frac{1}{2 \pi \phi h} \sum_{j=1}^n q_j \left\{ \frac{x-x_j}{(x-x_j)^2 + (y-y_j)^2} \right\} \dots \dots \dots (6)$$

$$V_y = \frac{1}{2 \pi \phi h} \sum_{j=1}^n q_j \left\{ \frac{y-y_j}{(x-x_j)^2 + (y-y_j)^2} \right\} \dots \dots \dots (7)$$

where: h = formation thickness

φ = porosity

n = total number of wells in the system

q_j = flow rate of well "j"

x,y = coordinate distances

The streamline position is determined by incrementing the locations x,y of the particle of fluid as they move. For example, the new location x_n,y_n is given below.

$$x_n = x_{n-1} + V_x \Delta t \dots \dots \dots (8)$$

$$y_n = y_{n-1} + V_y \Delta t \dots \dots \dots (9)$$

where V_x,V_y are obtained from equations (6) and (7) above.

Stream tubes are modeled by combining the flow velocity calculated from the streamline and the known volumetric flow rate of the well. Since at any time we know the volumetric flux at a given location, we can determine the cross sectional area open to flow. This area

can be used with the formation thickness at that location to compute the width of the stream tube. This width is now superimposed on a vector perpendicular to the velocity vector. The loci of the extremities of these widths provide the boundaries of the stream tubes.

Mathematically,

$$\text{Volumetric Flow (Q)} = \text{Velocity} \cdot \text{Area}$$

$$\text{Area} = \frac{\text{Flow}}{\text{Velocity}}$$

$$\text{Area} = \text{Width} \cdot \text{Thickness}$$

$$\therefore \text{Width} = \text{Area} / \text{Thickness}$$

This is illustrated in Figure 23.

9.2.2.2 Thermal Front

The problem of defining the location of the thermal front between the injector-producer pairs involves solution of a hydrodynamic and heat transfer problem. Consider a stream tube with an injector at one end and terminating in a producer at the other end. As the injected brine flows through this quasi-linear system, there is conductive heat transfer from the fluid to the rock matrix and convective heat transfer in the fluid. The magnitude of each of these heat flux components depends on flow velocity, rock and fluid properties.

The governing equation for the temperature distribution is given by equation (10) with its attendant initial and boundary conditions.

$$k \frac{\partial^2 T}{\partial x^2} - \rho_w c_w v_x \frac{\partial T}{\partial x} = \{ \phi \rho_w c_w + (1-\phi) \rho_r c_r \} \frac{\partial T}{\partial t} \dots \dots \dots (10)$$

$$T(x, 0) = T_o(x) \qquad \text{initial conditions}$$

$$T(0, t) = T_i \qquad \text{inlet conditions}$$

$$-k \frac{\partial T}{\partial x} + H_1 T = H_1 T_1 \qquad \text{outlet conditions}$$

where:

H = heat transfer term

subscripts:

t = time

w = water (brine)

T = temperature

r = rock

k = thermal conductivity

x = x direction

ρ = density

i = inlet of streamtube (x=0)

c = heat capacity

l = length of streamtube

ϕ = porosity

v = velocity

This equation is solved along a stream tube to determine $T(x,t)$ between the injector and the producer. The resultant temperature profile allows the determination of the location of the temperature front. The thermal front is significantly affected by injection rate, which translates directly into flow velocity, reservoir characteristics, porosity values and rock and fluid thermal properties.

We cannot understate the need for good reliable information on the thermal front locations. A model which would provide these kinds of data will alleviate one of the fundamental problems involved in developing alternate injection strategies. The work by Tsang⁶ which is an extension of the work of Gringarten²¹⁸ et al. shows an elementary application of this technique. It must be extended even further to incorporate some of the peculiar characteristics of brine flow, particularly the thermodynamic changes and also to incorporate reservoir heterogeneities.

9.2.2.3 Hydrodynamic Front and Arrival Mixing of Fluids

This front is the actual location of the injected water in the system. It is readily determined by integrating the streamline velocity along the stream tube, for example:

$$\frac{dx}{dt} = v_x$$

from streamline data

$$x_n = x_{n-1} + v_x \Delta t$$

The streamline velocity is the velocity within the porous media given by the Darcy flow equation.

The interrelation between the thermal and hydrodynamic fronts are shown in Figure 24.

Associated with the hydrodynamic front is a corollary problem which could develop when two different waters are being used in the geothermal reservoir, e.g., Niland water (NW) and Salton Sea Water (SSW). Consider the situation where the Salton sea water is being injected into the reservoir and it displaces Niland water at its leading edge. Our assumption is that this displacement takes place in a piston-like manner and a hydrodynamic front exists at the SSW/NW interface.

As the displacement process occurs and the injected fluid moves towards the producers, the produced fluid will have initially all Niland water composition and an ever increasing fraction of SSW as the contributions from these stream tubes which have broken through increase. This is illustrated in Figure 25. Because of the longer paths taken by the fluids as they move under the pressure gradients, there would be different arrival times for the hydrodynamic front in each stream tube; this creates an "arrival mixing" of NW and SSW. As the SSW fronts arrive at the producer, there would be significant variation in the fluid chemical composition. This variation can be quantified by a predictive model which determines the arrival times and arrival rates for a given injector/producer system. The arrival sequence is shown in Figure 26. As the number of streamlines modeled increases, the graph will lose its discrete nature and become a continuous curve. The arrival mixing and resultant chemical composition of the produced fluid is routinely calculated by a simple material balance at the producer to add the contributing effects of each stream tube.

The location and definition of these hydrodynamic and thermal fronts can also be made by using the standard and geothermal reservoir simulators (finite difference models). However, we suggest the use of the streamline models here, because of their ease of use and relatively low cost when used in this type of routine reservoir analysis.

The streamline model allows us to look at localized well groups in the reservoir or any combination of these groups. The generalized geothermal reservoir simulator must always solve the whole reservoir problem everytime it is used. One cannot arbitrarily select a localized area for more detailed study. Another advantage of the streamline approach is that it allows this type of analysis to be done.

9.3 Specific Temperature Problems

The temperatures of the reinjected brine and reservoir deserve some more attention than outlined in the previous paragraphs. The injectivity of the reservoir and injectability of the brine are affected by temperature to a certain degree. Critical parameters of the brine such as brine viscosity, density and partial vapor pressures will effect the injection operations in a very obvious way. However, there are also other temperature related properties and problems which need to be evaluated in some detail.

9.3.1 Volume Deficiency Including Subsidence Problems

Cooling towers and other power plant operations can cause considerable losses of water. These water losses will lead to a water "deficiency" within the reservoir and will eventually cause pressure decreases in the reservoir. These water losses may also create the potential danger for subsidence. The authors of this present report have no expertise in determining the causes for any subsidence. However, two problems seem to be rather obvious:

- 1) Releasing the pressure from a geothermal reservoir is a precondition for subsidence.
- 2) Any subsidence caused by the operation of a geothermal field could spell disaster for the still infantile industry.

The volume deficiencies caused by temperature changes due to reinjection should also be determined and considered in any future large scale reinjection.

9.3.2 Temperature Dependent Permeability Changes

Weinbrandt and Remy²¹⁹ reported a considerable effect of temperature on the relative permeability of sandstones. Private communications with personnel at various research centers of major oil companies have indicated that some results of this work could not be duplicated. On the other hand, it has been noted in some reinjection wells (East Mesa Area) that a decrease of reinjection temperature was accompanied by a decrease of injection pressure at constant injection rate. The topic seems to be important enough to warrant more research efforts.

10.0 PRESSURE MAINTENANCE THROUGH IMPORTED MAKE-UP WATER

Theoretically, any water deficiency and its corresponding pressure drop in a geothermal reservoir could be overcome by importing water to the reinjection wells. If an accessible and cheap source of water is nearby, the process could offer considerable advantages. Besides pressure maintenance and avoidance of subsidence problems, the valuable condensate water could become a valuable commodity. It could be sold instead of using it as cooling water or reinjecting it into the reservoir. For example, injecting Salton Sea water into the Niland reservoir and recovering the condensate water could generate a number of benefits:

- 1) Valuable and desperately needed irrigation water could be sold to the agricultural industry.
- 2) The high salt content of the Salton Sea water and its dangerously rising level could be decreased.

Presently, the Salton Sea is considered the "sink of California". Using the excess water of Salton Sea for injection into geothermal reservoirs would not only solve environmental problems, it would also allow the recovery of additional heat reserves from the geothermal reservoirs. The economical, socioeconomic and political benefits from such an operation could be tremendous. However, there are also a number of problems expected to arise during reinjection of imported waters.

10.1 Chemical Water Incompatibility Problems: Scale Formation

Scale formation is one of the major potential problems generated by importing of waters into a geothermal reservoir. For example, some Niland brines contain large concentrations of barium and calcium ions, whereas the Salton Sea waters contain considerable concentrations of sulfate ions. It is rather obvious that BaSO_4 and CaSO_4 scale depositions could offer serious operating problems.

Injection of waters which are chemically incompatible with the native reservoir materials can lead to scale formation in a number of critical locations in the field. However, the authors feel that the problems generated through incompatible water injection can be handled if this injection is properly conducted. The advantages of this injection may outweigh its disadvantages.

10.1.1 Precalculations of Potential Scale Problems Caused by Injection of Incompatible Waters

The authors published in a recent paper²²⁰ (see Appendix) a reliable method to calculate the precipitation of BaSO_4 , SrSO_4 and CaSO_4 caused by the injection of incompatible waters. The new computer model (VESCAL II, see Appendix) allows this calculation. However, these calculations assume a thorough mixing of the injected brine and reservoir brine within the reservoir. An isotropic reservoir is assumed, i.e., no mixing close to or within the production wellbores is allowed. This mixing in or close to the production wellbores can lead to extreme scale problems within the production wellbores. Figure 27 shows this potential danger of mixing due to horizontal reservoir heterogeneities, whereas Figure 28 illustrates the effects of vertical heterogeneities.

In addition, this potentially dangerous wellbore mixing can also occur in an isotropic reservoir. Figures 25, 26 and 29 indicate the different arrival times of the various water mixtures in the producing wells. These different arrival times can lead to the detrimental mixing in the wellbores.

It is suggested to refine these calculations first for an isotropic reservoir and, then, extend them to an anisotropic reservoir, i.e., a reservoir containing extreme heterogeneities such as high permeability streaks (see Figures 27 and 28) and fractures.

The calculations for an isotropic reservoir could be performed by utilizing another new model. A precipitation simulator (e.g., VESCAL II, see Figures 3 and 4) could be combined with a conventional reservoir simulator. One of the possible combinations is a simple version VESCAL I (see Figure 5). Addition of a mixing simulator can lead to a more sophisticated version of VESCAL I (see Figure 6).

The calculations using the latter version of VESCAL I (see Figure 6) could be started immediately under Phase II of this present study. This basic work will describe the mixing of incompatible waters and its detrimental scale formation throughout the field if an isotropic reservoir is assumed.

A still more complicated combination of various simulators could be applied to reservoirs containing pronounced heterogeneities (VESCAL III, see Figure 30). However, the partial tracer data interpreter needed for VESCAL III requires a tracer study as outlined later in this report. The utilization of VESCAL III would decrease or almost eliminate the risk of generating unsurmountable scale problems caused by injecting of chemically incompatible waters into the geothermal reservoir. It simply means that a reservoir tracer study must be performed first to obtain the data required for calculating the potential risks involved in the injection of incompatible waters. This, in return, means that the injection of incompatible waters should not be commenced at the start of any full scale routine of reinjection operations but must wait for 2-3 years so that the necessary tracer information has been generated.

It is felt that this model development should be pursued under all circumstances. Parts of the proposed or already available models are not only needed for the injection of imported incompatible waters but also for other aspects of proper reservoir management as outlined in later portions of this report.

10.1.2 Dedicated Injectors for Different Brines

Mixing of imported water with reinjection brine within surface facilities and injection of the resulting mixtures does not seem to be the proper approach. For example, mixing of Salton Sea water with the heat-depleted brine produced in the Niland area can lead to tremendous scaling rates within the surface facilities and injection wells. The only alternative would be to designate certain injection wells for injection of imported water and other injectors for reinjection of the heat-depleted native brine. Proper location of the various dedicated injection wells within the field must be evaluated using the model considerations outlined above.

10.2 Physical Water Incompatibility

Injection of imported water is not only accompanied by chemical compatibility problems but also by physical injection difficulties. Suspended particles

in the imported water may have to be removed to ensure trouble-free operation of the dedicated injection wells. This particle removal may require techniques quite different from those needed for the particle removal in the heat-depleted native brine. The particles suspended in the imported water must be removed in an economically feasible way. Even simple particle removal techniques such as filtration and settling (see later in this report) may require large capital investments and operating expenses. This problem should also be evaluated in considerable detail before any of these pressure maintenance methods are seriously considered.

11.0 SUGGESTED SOLUTIONS TO INJECTION PROBLEMS: PREVENTIVE MEASURES

In this chapter we make an attempt to line out some of the ideas and thoughts which will aid in preventing major damage of geothermal reinjection wells and reservoirs. The suggestions resulting from this evaluation are concerned with reaching a better understanding of the critical injectivity and injectability problems through describing and modeling the most critical parameters. The better understanding of these parameters through modeling can then be applied in the field to constantly monitor the brine qualities and well injectivity. Finally, utilizing the brine quality data obtained in the field will permit the operator to take appropriate measures and adjustments in the field to prevent major damage anywhere in his operations.

11.1 Pre-Injection Brine Treatment: Particle Monitoring, Modeling and Removal

As mentioned before, suspended particles are one of the most critical parameters concerning the brine injectivity. Major efforts must be undertaken to study the particle characteristics and behavior in geothermal brines. Our only answers to the most complex problems caused by suspended particles are:

- 1) Particle monitoring techniques must be developed. These techniques must be applicable and affordable for daily routine field operations.
- 2) The interrelations between the properties of these particles and the porous medium (plugging) must be studied and described in fairly simple, field applicable models.
- 3) Guidelines for minimum brine qualities (regarding particles) must be established.
- 4) Particle removal techniques to obtain minimum brine quality must be found and applied in the field.

This work alone requires a major research effort. All concepts, methods and techniques developed must be evaluated in laboratory and field experiments.

11.1.1 Modeling of Relations Between Particles and Reservoir Injectivity

The Barkman-Davidson method¹⁸⁶ is presently the only accepted method to monitor and predict injector lifetimes as a function of some properties of the suspended particles. Unfortunately, it seems rather obvious that this method has some inherent disadvantages which are very difficult to overcome as mentioned in previous paragraphs.

The Barkman-Davidson approach uses a mass balance solution coupled with the experimental determination of several time dependent coefficients for the impairment process and formation of filter cake. It does not seem possible to directly utilize this technique in the geothermal industry for field operations because of the problems inherently present in the brines and the way in which the particles can develop (see previous paragraphs).

The problems could be alleviated to some degree by a combination of an improved laboratory technique, an improved reservoir representation and an improved approach in modeling the transport and filtration process.

Stanley²²² and Ives²²³ used radioactive tracer techniques to develop more comprehensive interpretations of the filtration process. The mechanisms which have customarily been believed responsible for plugging were physical, i.e., pore size, particle size, flow rate, and fluid properties have been shown to be insufficient to explain the degree of plugging and injectivity decline. Omilia and Crapps²²⁴ have included additional parameters based on chemical properties which have been recognized as contributing to the particle invasion and filtration process. These include surface properties, ionic and pH properties of the fluids. Several additional investigators²²⁵⁻²³⁰ have reported on the phenomena of particle transport and filtration in porous media. The bulk of their work refers to non-geothermal fluids and particles which are fixed in size. This work has to be extended to geothermal system and an approach to solving the problem must include the ability to represent both in the laboratory and in modeling the true nature of the particles and the reservoir rock.

It is obvious that a truly representative model will not be possible. However, it is feasible that a statistical approach can be formulated which would allow us to approximate more readily the problems which develop because of particle size and pore size distribution in the geothermal fluids and geothermal reservoirs. Figure 31 shows a representative particle size distribution. It is instructive to note that the work done to date -with one exception - does not allow the incorporation of the particle and pore size distributions into the analysis. Donaldson¹⁸⁸ et al. have published an elegant approach which can be modified to investigate the cake formation and deep plugging within the wellbore region of the geothermal injector. Using this approach we can develop

predictive equations and curves for the response of the injectors during plugging. These equations and curves are analogous to the Barkman-Davidson type information, but will present the data for a given particle distribution. This technique involves the use of a Monte-Carlo type approach coupled with a realistic representation of the porous medium in the region of the wellbore. The technology is present today to allow us to do this. Determining a priori the behavior of the geothermal formation to particle invasion and plugging should be achievable. For instance we can develop the expected growth in filter cake and the resultant pressure loss from this approach. This improved method will not require any additional information than that which is currently used in geothermal reservoir work and the new differential light scattering devices (see later in this report) can generate the in situ particle distribution as needed.

To overcome some of the reservoir problems imposed by the original Barkman-Davidson method, we must look at the reservoir in greater petrophysical detail and consider the properties and distribution of the particles in the injected fluid more analytically. The method must account for the variation in permeabilities and thicknesses in each zone (layer) which is taking fluid. To do this in a useful sense, we must be able to characterize the whole formation by a simple unique representative parameter which is related to the permeability-thickness distribution. A fruitful approach could be the use of a Dykstra-Parsons type correlation parameter "V" which allows the engineer to represent the permeability variation of the various layers. The technique involves plotting the logarithm of permeability versus cumulative percentage on probability paper - see Figure 32. The variation parameter is defined as:

$$V = \frac{k_{50} - k_{84.1}}{k_{50}}$$

It has already been indicated that actual core work should replace the millipore filters. The core samples should duplicate the actual permeability values expected in the field. These tests should be run on layered core samples to allow the distribution of the filter cake on the injection face to be ascertained.

11.1.2 Modeling Injectivity Decline Due to Suspended Particles

Injectivity decline is affected by several parameters in geothermal systems. Modeling injectivity decline is a factor which the geothermal industry must face in order to predict the future behavior of the reinjection wells and to design their total operating systems. It is our intention to point out some of the problems involved in modeling a real system and secondarily to suggest a possible approach to achieve a workable answer.

Geothermal reservoir formations, like any other porous and permeable strata, are comprised of distinct layers which have different petrophysical properties as shown in Figure 33. During a reinjection in the field, each of these layers will take varying quantities of fluid and, therefore, form a different type and size of filter cake (see Figure 34); in other words, the impairment process can occur in many different ways simultaneously. The engineer must be able to predict this behavior for real rock systems with real fluids. Secondly, the particle size and particle distribution will significantly affect the properties of the filter cake and collars formed by these particles. Finally, the flow rate generally encountered in geothermal systems is much larger than those encountered in oilfield systems; these large injection rates lead to higher specific injection rates per foot of section. The point of this discussion is that the complexity of the fluid/porous medium system necessitates a more far-reaching approach to obtain realistic answers than those put forward in the petroleum literature.

We are convinced that this problem can be modeled by a combination of novel reservoir engineering approaches and some precise laboratory techniques to produce field useable applications. It is our belief that the true petrophysical nature of the reservoir can be represented by a single parameter characteristically similar to the Dykstra-Parsons²²¹ correlation factor "V" which is so routinely used in oilfield waterflood work.

Furthermore, a laboratory core study utilizing cores representative of a wide range of rock conditions and fluids with suspended particles can provide the necessary data base to generate a workable set of predictive equations for injectivity decline. Equation (1) shows the type of predictive equation we consider applicable:

Equation 1: Injectivity Decline

$$ID = \frac{\sum h_i k_{fi}}{\sum h_i \left\{ \frac{\log (r_e/r_w)}{\frac{\log [(r_w \cdot e^{-\beta t})/r_w]}{k_c} + \frac{\log [r_e/(r_w \cdot e^{-\beta t})]}{k_f}} \right\}_i}$$

Where: h = layer thickness

k_f = permeability of individual layer

k_c = filter cake permeability

r_e = drainage radius

r_w = wellbore radius

β = composite term containing density, particle numbers and flow rate terms

i = individual layer index

ID = injectivity decline

The crucial portion of the solution to this problem is to provide a set of field curves which can then allow estimations of the decline of the reservoir injectivity. These curves will have a generic form as shown in Figure 35. They must include all normally measured parameters.

11.1.3 Particle Monitoring

Correct particle monitoring techniques in geothermal brines must be developed. A number of concepts and available instrumentation should be examined for their suitability to accomplish these important particle measurements in actual field operations.

Table 2 lists the more important particle properties to be used for reliable and useful particle monitoring. The actual methods or physical principles to be investigated for their suitability for particle monitoring in the field are listed in Table 3.

Proper instrumentation must be suggested after studying the various principles listed in Table 3. This instrumentation should allow on-line and instantaneous monitoring of all suspended particles which could impair the injectivity of geothermal wells.

Table 4 lists some of the requirements for any of these on-line instruments. Presently no such instrumentation exists in geothermal operations. A concentrated research effort has a good chance in resulting in the development of new instrumentation or in adapting presently available instrumentation with minor adjustments for geothermal field operations. The new or adapted instrumentation would provide constant particle monitoring for the highly desired brine quality control.

11.1.4 Particle Removal

Particle removal techniques must be evaluated. These techniques could involve physical removal by filtration or sedimentation. The filtration and/or sedimentation could also be aided by chemical additives. Previous work in this regard showed encouraging results in preventing injection wellbore and reservoir damage. For example, the reactor clarifier used in Magna's Niland operations seems to offer one of the technically and economically feasible methods. However, the fact that this reactor clarifier works with the Niland brine does not mean that this concept provides a workable solution to all particle removal problems in all geothermal operations and all geothermal areas.

A thorough investigation of various particle removal techniques for geothermal operations seems to be highly desirable at this present time.

The particle monitoring techniques mentioned in the previous paragraph can be used in the development and proper field application of all particle removal techniques. The combination of particle monitoring, particle/ reservoir modeling and particle removal techniques will guarantee an optimum reinjection method as far as wellbore and reservoir damage due to suspended particles is concerned.

11.1.4.1 Filtration - One of the methods to be studied in detail is filtration with and without chemical filter aids.²³³⁻²³⁵ Very recent publications concerning brine injectibility problems in oilfield operations stress the need for these investigations. A similar effort should be undertaken for the geothermal industry.

11.1.4.2 Flocculation - Flocculation methods²³³⁻²³⁵ may offer the best chance of removing the suspended particles from geothermal brines. These methods may have to be used in combination with filtration methods (see above) or sedimentation techniques (see below). Previous field tests with geothermal brines in the Westmorland area (unpublished results) showed extremely encouraging results. However, these techniques are very sensitive to over- and undertreatments with various types of chemicals.

Presently ongoing research efforts in our laboratories are concerned with the flocculation and flocculation mechanisms suitable for oilfield brines. Commercially available compounds are labeled with tritium to study their effects on the flocculation. It is strongly recommended to extend these laboratory studies to the treatment of high temperature geothermal brines. The mechanisms of flocculation of suspended particles in geothermal brines are expected to deviate greatly from those in oilfield brines due to the higher temperatures and thermodynamic instability of the geothermal brines. Without a thorough laboratory and field study of these flocculation mechanisms, all attempts in the field to

find and utilize commercially available flocculants may remain haphazard. It is economically and technically not feasible to evaluate these chemicals and processes in the field without previous laboratory experiments. Presently ongoing field tests may miss the potentially most valuable methods and chemicals due to sampling and side stream problems mentioned in previous reports.²³⁶ Laboratory evaluations similar to those described for scale inhibitors¹⁹⁹ should be applied to flocculants. These evaluations could include labeling of the tested chemicals with radioactive isotopes (tritium and C-14) and should involve the instrumentation proposed for monitoring of suspended particles (see previous paragraphs). Only this combined laboratory/field study will result in concrete and useful information for the geothermal industry.

11.1.4.3 Settling, Sedimentation and Related Processes

Filtration and flocculation methods employing sophisticated chemical techniques and mechanical equipment may not offer economically viable solutions to many problems generated by suspended particles. Settling and sedimentation methods in combination with filtration and/or flocculation may be the final answer. These techniques should be evaluated in Phase II of this presently ongoing research project on geothermal reinjection. These topics should be of top priority in the proposed combination of this work.

11.2 Pre-Injection Brine Treatment: Chemical Stabilization Through Scale Inhibition

To minimize particle formation, deposition of scale and injection well impairment, a chemical stabilization of the brine may be attempted. Some chemical brine alterations as previously suggested may have financial drawbacks²³⁶ and may not be affordable. However, using the vent gases (see earlier in this report) or chemical inhibitors at below stoichiometric ratios may offer a means of improving the brine injectability.

One method of preventing the formation of suspended particles and scale in geothermal reinjection systems is the utilization of scale inhibitors. Adding of scale inhibitors to any brine may not only show beneficial reactions (scale inhibition) but may also show detrimental effects^{199,200} because of brine/scale inhibitor and reservoir rock/scale inhibitor interferences. The formation of pseudo-scale can cause extreme injection problems. These pseudo-scales are the chemical reaction products between the added scale inhibitor and certain brine components (e.g., divalent ions such as Ca^{++} , Mg^{++} and Fe^{++}).

Previous scale inhibition studies have not been extended beyond 350°F (177°C). The inhibitor efficiencies²⁰⁰ should be determined above this temperature even though reinjection temperatures may never reach this high temperature. However, to make full use of the scale inhibitors, these chemicals should be added to the producing system of the geothermal operation to protect both production and reinjection wells.

The compatibility problems between scale inhibitors and reservoir rock and/or scale inhibitors and brine at various temperatures should also be studied in detail. The adsorption of the inhibitors on suspended particles or the rock material must be known. Finally, the interactions between scale inhibitors and various other types of chemical additives (flocculants, corrosion inhibitors, filter aids, etc.) can also lead to severe injection problems and undesired side reactions ("scavenging" of chemical additives) and, therefore, should be evaluated in detail.

All additives used in geothermal field operations should be tested as to their adsorption/desorption characteristics on the rock matrix in the reservoir. Any accumulation of these materials in the near wellbore regions of the reservoir can lead to a change of the rock-water contact angle (wettability) and with that to severe declines of the injectivity.

These investigations of the behavior of chemical additives used in or suggested for geothermal brines could employ proven laboratory and field techniques such as labeling of the compounds with radioactive isotopes to avoid the most common analytical problems encountered in studies of this nature.

11.3 Reservoir Verification, Monitoring and Management Through the Use of Tracers

In two recent papers on the use of tracers in geothermal injection systems,^{237,238} we outlined the advantages to be gained through the proper use of reservoir tracers. Reservoir problems existing distant from the injection or production wellbore cannot be evaluated in enough detail using conventional reservoir engineering techniques such as rate and pressure transient testing. Tracers, on the other hand, are ideally suited for investigating the reservoir at larger distances from the wellbores. This means that conventional reservoir engineering and sophisticated tracer technologies must compliment each other.

Unfortunately, no sophisticated tracer technology and interpretation methodology for tracer elution profiles exist today even though we know of quite a few recent attempts to use tracers in geothermal injection systems. One of the authors has used tritiated water extensively and, to some extent, silver 110 m in geothermal operations (unpublished, proprietary data). Through this work he has become thoroughly familiar with the present problems regarding various radioactive tracer techniques. It is our opinion that many of the most obvious problems regarding the utilization of tracers in geothermal operations, particularly in the reservoir, could be solved with relatively little effort. It is strongly suggested that DOE/DGE pursues this type of research to generate a technology of extreme value to the geothermal industry.

11.3.1 General Concepts of Using Tracers

Conventional (chemical) and radioactive tracers have been used extensively for reservoir tracer jobs in oilfield operations.²³⁹⁻²⁴⁶ Most of these publications are concerned with well-to-well tracer jobs designed to determine fluid flow characteristics within the reservoir. The basic concept of this technique is to add a tracer to the injected fluid and then assume that the added tracer follows the same flow pattern as the injected fluid. Determining the concentration of tracer in the produced fluid (elution profiles) will then permit conclusions to be drawn regarding the fluid flow patterns within the reservoir. By and large, the tracer will be added when a reservoir problem is suspected, i.e., when a problem is already evident.

Another concept favored by these authors is the use of one tracer (tritiated water, see next paragraph) for constant and routine reservoir verification and monitoring.^{237,238} As soon as this tracer indicates any problems in the reservoir an additional, more precise and detailed tracer study should be performed in the field.

Still other concepts include the tracer injection into a well and back-producing the fluids to investigate reservoir problems closer to the wellbore. This latter technique will allow "thief zones" and other unexpected reservoir heterogeneities closer to the wellbore to be determined.

Finally, the use of tracers in surface operations will allow the determination of various physical and chemical fluid characteristics within the geothermal flow systems within surface equipment. This technique is largely ignored by the geothermal industry. For example, flow regimes and the velocities of various fluid phases could easily be determined by this technique (see Figure 36). This type of work could be performed by using radioactive tracers and "through pipe measurements", i.e., a constant measuring of some critical fluid properties could be achieved by receiving, measuring and processing of signals (X-ray or γ radiation) by instrumentation mounted outside the surface installations. Velocities, flow regimes and phase behavior of the various phases (suspended particles, liquid brine and steam) could be determined depending upon (a) the location where the collimators and scintillation detectors are mounted and (b) the type of tracer injection (continuous or intermittent).

Another, somewhat different variation of this latter tracer technique, is the use of radioactive isotope tracers to determine various types of precipitation reactions in geothermal flow systems. For example, the precipitation of heavy metal sulfides and the formation of suspended solids can be fairly easily determined and monitored by using this technique. Previous experiments (unpublished, proprietary results) have indicated that an almost perfect mass balance between sulfides (a) dissolved in the brine, (b) suspended in solution, (c) attached to the pipe (scale) and (d) coprecipitated with other solids (e.g.,

silica) can be achieved. This work should be continued in studying the formation mechanisms of scale deposits in geothermal injection systems.

11.3.2 Use of Radioactive Tracers for Reservoir Monitoring and Verification

In previously-mentioned papers^{237,238} we described the importance of radioactive tracers for geothermal reservoir verification and monitoring. The basic idea is to add a tracer, preferably tritiated water, to the reinjected fluid at the time when routine injection is started. This tracer supposedly will follow the hydraulic front. Constant analyses of the produced brine for its tracer concentration will then allow various flow problems existing with the reservoir to be determined. Figure 37 shows the measured tracer profiles in two different wells. Profile I (see Figure 37) indicates at least four (4) high permeability streaks, whereas profile II represents a flow behavior in a more homogeneous reservoir with no extreme variations of the reservoir permeability.

We would like to stress the potential value of this technique for geothermal operations. Even a slight variation of the measured from the predicted sweep pattern of the reinjected brine, i.e., the measured vs. predicted hydraulic front break-through will have a large economical and technical impact on the operation of the reservoir.

Any severe channeling of the tracer from reinjection well to a producing well is a clear indication that this portion of the reservoir does not behave as expected by the reservoir engineer. Immediate changes in the well pattern and location must be made to prevent major temperature damage to the reservoir and to optimize energy recovery from the reservoir. Thus, this general tracer technique will provide an excellent means of reservoir monitoring and verification.

Only radioactive tracers should be considered for this type of tracer test. Chemical tracers are unsatisfactory because of the large volumes of geothermal fluid being handled and the lack of adequate analytical techniques required to detect the chemical tracers. Analytical techniques presently exist that can detect radioactive tracers at concentrations much lower than conventional chemical tracers. The authors believe that tritiated water is the logical selection for radiotracer monitoring.

If more detailed information about the flow behavior within the reservoir is required, a second and more specific tracer test can follow this first test. This second tracer test is tailored to the very site-specific situation in the field. A new concept for this more site-specific tracer test is described below.

11.3.3 Tracer Adsorption Chromatography for Specific Applications

Conventional tracer applications are concerned with the injection of single tracers into various wells within the field. Preferably, each well receives a different tracer. This means, a large number of different tracers may be required for a large-scale tracer study in a multi-well field. Figure 38 shows the minimum number of tracers necessary in a reservoir showing a geometric well pattern ("five spot"). Choice II (see Figure 38) shows that at least nine (9) different tracers should be considered if each neighboring injection well should receive a different tracer.

Unfortunately, each tracer (including tritium!) will exhibit certain adsorption effects when contacted by the rock phase within the reservoir (see Figure 39). Despite common belief among many reservoir engineers, adsorption must take place if any chemical (including radioactive isotopes) in solution comes in contact with the surface area of a solid phase. These adsorption characteristics will invariably cause retention of the tracer. The tracer will adsorb to a greater extent than the water to be traced. Thus, the tracer will show up in the producing wells at a later time than the water to be traced. This time delay will depend upon the adsorption/desorption characteristics of a given tracer under the given set of conditions within the reservoir. We must emphasize that this adsorption is due to chemical interactions between the rock and the radio labeled tracer. This adsorption would take place whether the tracer were labeled or not.

These time delays represent a major shortcoming in conventional tracer testing. The precise adsorption isotherms of various tracers (see Figures 40 and 41) under reservoir conditions are generally not known and are, therefore, ignored in most evaluations of tracer profiles.^{241,245,246} Even if these isotherms would be known in detail, some major data interpretation problems would still exist.

The authors suggest a new approach in reservoir tracer test work to overcome these problems caused by the specific adsorption characteristics of various tracers. Not one, but at least two tracers could be injected into each injection well. Figure 38 shows that the number of tracers required for a geometric well pattern would increase from nine (9) to eighteen (18) tracers unless one tracer is common for all injection wells (see Choice IV in Figure 38). This common tracer could again be tritiated water. The total number of tracers required would then be ten (10).

If the adsorption/desorption characteristics of these ten tracers are investigated in laboratory experiments, all major interpretation problems would be eliminated. The different time delays between the break-through of the different tracers are directly related to the surface area contacted

by the two tracers injected into each well. Figure 41 shows the adsorption isotherms of two chosen tracers, whereas Figure 39 illustrates the effects of different adsorption isotherms on the tracer elution profile in the produced brine. The relations "material adsorbed on the solid phase vs. material dissolved in the liquid phase" (see Figure 41) and "retention time of tracer A vs. retention time of tracer B" (see Figure 39) can now be used to calculate the actual surface area within the reservoir contacted by the two tracers.

Using two tracers having different adsorption characteristics in a reservoir and, in addition, showing three different fractures would yield a tracer elution profile similar to that shown in Figure 42. The resulting retention times (t_1 to t_6 ; see Figure 42) in combination with the adsorption isotherms (see Figure 41) can now be used for precise calculations of the contacted surface area as mentioned above.

It should be possible to use this tracer chromatography method to obtain fairly precise measurements of the contacted surface areas within the reservoir. This information would allow us to draw some accurate conclusions as to the porosity and, hopefully, permeability of the flow channels through which the tracers have travelled from the injection wells to the producing wells. In other words, major reservoir heterogeneities such as high permeability streaks and fractures could be determined in a quantitative manner.

11.3.4 Modeling of Tracer Elution Profiles

The flow of tracers in porous media has been the subject of many theoretical and experimental studies. There is a need to use this accumulated knowledge as a starting point in the solution of tracer flow problems in geothermal systems. As indicated earlier in this section, tracer technology is used as a design and a diagnostic tool. This approach can be very instrumental in reservoir verification if the operator can analyse the data which is produced in the form of elution profiles from these tracer tests.

Tracer flow can be modeled from two entirely different strategies. These approaches are based on:

- a. Mass balance laws
- b. Statistical techniques

The majority of investigators use the mass balance²⁴⁷⁻²⁴⁹ approach as opposed to the statistical approach.²⁵⁰ This technique conserves the dispersing material by equating net fluxes into and out of a control volume to the accumulation within the volume. The statistical approach uses a Monte Carlo approximation to the tracer particle behavior. A large number of particles are "injected" into the system to simulate

the tracer material and the trajectories are calculated by probability distributions which are determined independently. The mass balance approach is more easily applicable to geothermal tracer work. The fundamental tracer flow process is complicated by other naturally occurring phenomena which make it essential that adequate modeling of the elution profiles take these into account. These processes are:

- a. Adsorption-desorption
- b. Radioactive decay

The elution profile model involves a mathematical equation which completely describes the flow in porous media. These equations are then solved either numerically or analytically to produce useable interpretations. The simplest form of the tracer equation is:

$$\frac{\delta}{\delta x} \left[D \frac{\delta C}{\delta x} - \mu C \right] = \frac{\delta C}{\delta t} \quad \dots \dots \dots (1)$$

where C = concentration of tracer in produced water

μ = flow velocity

D = a complex coefficient which describes the dispersion of the tracer material

The dispersion coefficient is a composite term and its precise definition is not presently possible. However, empirical verification of values for the dispersion coefficient are mutually made. This process will involve a combination of laboratory work and numerical modeling techniques to allow a more precise value of "D". There are two possible ways that a tracer can be put into a system. First, as a continuous injection and secondly, as a single pulse injected over a relatively short period of time. The continuous injection process is not economically feasible since it involves a large volume of tracer material.

In geothermal systems there are two problems which complicate the tracer elution profile determination. These are viz: the adsorption-desorption phenomena and the accurate determination of the dispersion coefficient to be used in the mathematical modeling process. To make effective use of the tracer technology these two problems must be solved to allow the engineer to develop confidence in his analytical techniques; he must be confident that his tools used in elution profile analyses have the necessary precision to make judicious conclusions from field observation.

To accomplish the above objective there must be a coordination of modeling and laboratory studies to develop the tools. To date the laboratory

work on defining the tracer parameters, particularly the dispersion coefficient, have not looked at the information necessary to provide adequate data for geothermal work. Levenspiel and Smith²⁵¹ have discussed a technique for determining this coefficient "D" from experimental data. Their experiments used KMnO_4 solutions as the tracer material. Their approach is theoretically sound but extension to the geothermal fluids and temperatures must be made. Gupta and Greenkorn²⁵² elaborated on a method first published by Taylor²⁵³ which uses differential empirical data to determine the coefficient "D".

These empirical techniques have been widely used in groundwater hydrology and filtration work at low temperatures and high flow rates. The geothermal system require two departures from the above since our temperatures are higher and flow rates within the geothermal reservoir can be very different from the published conditions.

Considerable work has been done on adsorption-desorption in porous media. The development of the adsorption terms must be furthered for use in geothermal systems.

Once the definitive parameters have been set by experimental research the engineer must use these in his field work. The tracer models have to incorporate the additional terms necessary to describe these phenomena; this addition complicates the equation. For example, the adsorption term changes eq (1) to:

$$\frac{\delta}{\delta x} \left[D \frac{\delta c}{\delta x} - \mu C \right] = \frac{\delta c}{\delta t} + \frac{\delta C_a}{\delta t} \quad \dots \dots \dots (2)$$

where C_a = the mass adsorbed on the rock matrix.

This accumulation term is based on the adsorption-desorption isotherms and can have rather complicated forms as indicated by Lapidus.²⁵⁴

By including the radioactive decay of the tracer, the equation becomes:

$$\frac{\delta}{\delta x} \left[D \frac{\delta c}{\delta x} - \mu C \right] - \lambda C = \frac{\delta c}{\delta t} + \frac{\delta C_a}{\delta t} \quad \dots \dots \dots (3)$$

where λ = coefficient of radioactive decay

Numerical modeling of the tracer system is the only suitable way to account for most of the complications in a real geothermal system. The basic partial differential equations are solved numerically on a finite-difference grid. The technique involves a general weighted time centered scheme; the authors have used a similar approach²⁵⁵ in previous studies. Essentially the basic equation is discretized and an iterative technique used to solve the unknowns over a grid network.

Further research is needed to provide stable field useable models which are precise enough to allow good design and interpretation of field work and reservoir verification. This research must hinge around the stability problems in and adjacent to the concentration front and also compare the adequacies of the various levels of sophistication of the algorithms. A good model should provide the most useable information based on a minimum of good obtainable data. Some models are theoretically precise in terms of the academic definition of the problem but suffer serious drawbacks when used in the field because of lack of data or imprecise data. Tagamets and Sternberg²⁵⁶ have pointed out some of the possible problems that arise in modeling tracers for typical data ranges encountered in civil engineering work.

The analytical tools used by the geothermal engineer must be easily applicable to his problems and provide him with the kinds of results in the form that is instantly useable.

11.3.5 Need for Better Data Base

Precise knowledge of the adsorption/desorption characteristics of any chosen reservoir tracer is required. There is no data available as to these adsorption/desorption properties of potential tracers under the thermodynamic conditions encountered in geothermal reservoirs. Particularly the effects of temperature and type of rock material on the basic adsorption isotherms must be known.

In addition, the choice of presently available tracers for the high reservoir temperatures seems to be rather limited. Conventional chemical tracers such as organic materials and inorganic complexes have very little chance of being useful. The hydrolytic stability of these conventional tracers may not be sufficient to withstand the reservoir conditions.

Chemical tracers in general should not be seriously considered because of the extremely high flow rates unique for geothermal operations. The huge amounts of chemical tracer required for these tracer tests in geothermal reservoirs would be extremely expensive. In addition, the volume of material required would introduce logistic problems. Just the injection of the tracers into the stream of reinjected brine (on the order of 10,000 to 100,000 barrels per day) would require large and bulky tracer injection equipment. The volume of the tracer solution required would be on the order of 1,000 to 10,000 barrels per day.

Only radioactive tracers offer a chance of performing these required reservoir tests. Table 5 shows a comparison between a chemical and radioactive tracer for a reservoir supplying the brine (stream) for a 150 MW power plant. The volume of the radioactive tracer would not exceed 10 liters, whereas the volume of the chemical tracer (10% solution) would be on the order of ten million (10^7) liters.

Presently, the selection of radioactive tracers is rather limited because of the extremely high losses of the tracer due to various sorption effects in the reservoir (chemisorption and ionic exchange). Complex ions such as hexacyanocobaltates, etc., may offer the proper choice. However, very little is known about the hydrolytic stability of these complexes under geothermal reservoir conditions. Fairly simple and straightforward laboratory experiments could be designed and performed to select a reasonable number of potential candidates for these tracer tests. None of the required information could be found in the published literature.

11.4 High-Temperature Brine Reinjection

To avoid precipitation of silica and subsequent plugging of injection wells, some operators have attempted to reinject the brine at temperatures above the critical point at which silica precipitation starts. The authors do not believe that this approach offers a viable solution to the injection problems caused by silica precipitations.

According to Fournier²¹ the maximum solubility of quartz in geothermal brines falls into the range of approximately 600-700 mg/liter. The solubility decreases with decreasing temperature. The dissolved silica will not precipitate as quartz but as amorphous silica which shows a "solubility-temperature" relation quite different from that of quartz. Assuming the reservoir temperature is on the order of 300°C (572°F) and no flash occurs, the solubility of amorphous silica is exceeded if the brine temperature drops below 150°C (302°F). This means, amorphous silica will precipitate at or below this temperature. If the temperature drop is accompanied by a steam flash the remaining solution will be more concentrated in respect to the dissolved silica and, therefore, the precipitation will start at a higher temperature. Weres¹⁵¹ calculates in an example taken from the Cerro Prieto geothermal brine that silica precipitation can even occur at a reinjection temperature of 160°C (320°F).

It should be self-understood that the minimum temperature at which silica precipitation occurs will depend upon (a) the reservoir temperature, (b) brine composition and (c) percent flash. This means, this minimum temperature will vary from field to field and, possibly, even from well to well. As a rule, this minimum silica precipitation temperature will be the higher the higher the reservoir temperature and the larger the degree of flash before brine is reinjected.

It is our opinion that this high temperature reinjection does not solve the silica problem in a technically and economically feasible manner. In order to totally prevent the silica precipitation, the reinjection temperature must be increased the higher the reservoir temperature. This means the temperature span useable for energy extraction would become small for all geothermal operations, i.e., not only the high temperature resources but also the fairly low temperature reservoirs will be affected by this decreased span of useable energy.

This high-temperature reinjection would render geothermal energy highly noncompetitive with other types of energy sources. The number of producing wells will have to be increased for a given power output. This alone should be a deterrent for the high temperature reinjection because of the high cost of drilling and completing these extra wells. In addition, the useable energy extractable from a given reservoir would be greatly decreased compared to the recovery using the more common low temperature injection. The extra span of temperature in low temperature reinjection will almost double (in many instances) the energy recoverable from a geothermal reservoir. Finally, other types of scale such as heavy metal sulfides will cause scale problems which are, in many instances, worse than the silica problem. High temperature injection means that these sulfides will not completely precipitate in the surface installations where they can be removed with a profit. They will now be carried over into the injection wells where their removal becomes costly and annoying.

We believe that the prevention of silica precipitation in injection wells through high temperature injection should not be pursued because of technical and economical reasons. The authors feel that low temperature injection and proper silica removal will offer a much better chance of making geothermal energy an energy competitive with other energy sources.

12.0 SUGGESTED SOLUTIONS TO INJECTION PROBLEMS: REMEDIAL AND STIMULATION MEASURES

Up to this point the discussion has been limited to the extent and causes of injection problems in geothermal systems. The need for a fairly extensive research program to evaluate some potentially workable and operational methods to prevent future damages has also been discussed. In addition, there is still a definite need for properly designed wellbore stimulation procedures for a number of reasons:

- 1) Wellbore damage caused by drilling and completion practices
- 2) Naturally low permeability close to the injection wellbore
- 3) Particles suspended in the brine and not eliminated through proper particle removal processes
- 4) Scale and scale-related depositions

Any remedial or stimulation procedures must, of course, be tailored to the damage (type, extent, location) and the very site-specific conditions such as type of completion, wellbore geometry, temperature, remaining permeability (skin), chemical and physical structure of rock material, etc.

Each set of parameters (damage properties and site-specific conditions) requires its own work-over method, i.e., each individual stimulation job must be individually designed or engineered. On the other hand, there are some general rules for stimulation jobs due to problems which are not necessarily related to a specific geothermal site but which are more or less common for most geothermal injection systems. Some common features of stimulation jobs may be caused by these common damage parameters:

- 1) Huge rates of fluids and dissolved solids are required to be reinjected (see Tables 6 and 7) per field and even per well. Due to these huge injection volumes, even extremely small damages caused per liter of reinjected brine can lead to extremely massive damages as a function of injection time. This means, large quantities of stimulation fluids may be required in each job.
- 2) The thermodynamic instability of the reinjected brine causes a very unique set of damages in geothermal reinjection operations. This brine stability related damage can be found anywhere in the injector wellbore and can penetrate the formation over a large distance from the wellbore.
- 3) The high temperatures of the producing wells and the large temperature differential between producing and reinjection wells causes the precipitation of high temperature modifications of salts (scale) for which no readily available solution exists. Some of these crystal modifications may not even be known.
- 4) Work-over fluids commonly known from oilfield operations cannot be used in geothermal operations without extensive precautions because of the high temperatures. These work-over fluids may not be stable enough at these temperatures, i.e., they may decompose and cause secondary damages which can be worse than the primary damage these unstable work-over fluids were supposed to remove. Some of these work-over fluids, particularly acids, do not react at the high temperature with these deposits (damage) as assumed by extrapolation from their low temperature behavior. Recent field experiments (unpublished, proprietary information) have shown that reinjection wells can easily decline further after attempting stimulation jobs which are highly effective at lower temperatures.

- 5) Many stimulation methods used in oilfields cannot necessarily be applied in geothermal operations because of a temperature problem unique for geothermal fields: Any accelerated and localized penetration of cold fluids into the reservoir may cause severe temperature decreases in the producing wells, thus leading to an intolerable situation and heavy financial losses. For example, fracturing between the producing and injection wells in the direction from the injectors to the producers will invariably lead to the loss of otherwise recoverable energy reserves. These losses caused by "temperature damage" can easily amount to a large percentage of the potentially recoverable energy and with that to very large percentages of the total investment. Any accelerated advance of the hydraulic and temperature fronts (see Figures 22,24 and 25) due to inadequately designed stimulation methods can lead to financial disasters as indicated in Table 8.

It becomes obvious that new work-over (stimulation) techniques are needed for geothermal injection wells.

12.1 Damage Evaluation

Quite often, one of the more difficult problems of any wellbore stimulation job design is the determination of the damage itself. The design of the job and its probability of success strongly depend upon this damage. Wellbore logging may be very helpful in this damage determination. However, logging is expensive and hardly any logging tool will give us all the required information on the very critical properties of the materials causing the damage unless these materials are accumulated only within the wellbore. A bottomhole sample ("bailer") may also be required to retrieve a sample of the damaging materials to determine their chemical nature. This sample may provide the basis for the selection of the work-over fluid if it is determined that chemical stimulation offers the highest potential for the required stimulation procedure.

Frequently, the design of a stimulation job is based on assumptions instead of concrete information. In some instances, the cost for a work-over (stimulation) is lower than the cost for accumulating the proper information.

The authors suggest a different tool for accumulating the proper information about the damage itself and specific design features required for a successful chemical stimulation of geothermal reinjection wells:

A stimulation job could be designed by basing its main features on proper laboratory data and all information retrieved from the field. This may still be an inadequate design as mentioned above. The job,

with all its potential shortcomings, is then performed in the field. However, instead of displacing the spent stimulation fluids into the reservoir as commonly done in the field, these spent fluids will be produced back under careful monitoring of their volumes, rates and chemical composition (as function of cumulative volume and rate). The chemical composition and the chemical material balance between injected and produced fluids can now be used as an excellent tool in evaluating most chemical reactions within the well. Previous experimental field jobs of this nature allowed us to determine a large number of reactions between damaging materials and stimulation fluids. Various types of additives (corrosion inhibitors, foaming agents to lighten the fluids, etc.) were evaluated. Actually, in one specific job (unpublished, proprietary data) we were able to determine even the corrosion inhibitor film life on the steel downhole and the high temperature reaction mechanism of hydrofluoric acid on the formation material as a function of temperature.

Tracers of various types can be added to allow an even more sophisticated evaluation of the chemical reactions during this stimulation job. In a sense, this type of "diagnostic stimulation" procedure can be considered a squeeze job²⁵⁷ with simultaneously ongoing chemical reactions. The addition of at least two tracers may result in tracer elution profiles as indicated in Figure 43. For example, the amount of rock material (formation rock) contact by the fluids could easily be evaluated by this diagnostic stimulation.

The main problem in using this tracer technique is the fact that precise laboratory data on the adsorption/desorption characteristics of the applied tracers must be obtained prior to the actual field job. Another feature of these tracers could be to use a single tracer which decomposes into known fractions (e.g., an ester will hydrolyze into an acid and an alcohol). The tracer return profile would now show a number of additional tracers based on this decomposition reaction. The defined decomposition products and their return profile could be used as additional information to determine the surface area of all solids contacted by the stimulation fluid. This technique would be a special application of the adsorption tracer technology mentioned earlier in this report.

The mathematical treatment required for the interpretation of these tracer return profiles are fairly simple. The entire method is quite similar to that published by Dalton²⁵⁸ who used tracer "partition chromatography" to determine residual oil whereas we want to determine physical rock and damage properties by using tracer "adsorption chromatography".

It should be self-understood that this stimulation design is not necessarily a routine operation but only a special diagnostic tool to:

- 1) Determine the type and distribution of damaging materials in the well and
- 2) Evaluate the possibility of various features of a stimulation method to remove these damaging materials.

The information from these experimental field jobs can then be used to design routine jobs for the stimulation of geothermal injectors in various areas and wells.

12.2 Laboratory Evaluations

Stimulation fluids frequently used in oilfield operations may not be very useful in geothermal operations for the reasons outlined before. For example, recent attempts in using mud acid, i.e., various mixtures of HCl and HF (proprietary, unpublished data) revealed that the HF or its reaction products were not produced back as opposed to the HCl and its reaction products. The result of these experimental work-overs was heavy damage caused by the mud acid. It is our opinion that the high temperature reservoir rock and the damaging materials in geothermal operations act quite differently with common stimulation fluids than those common for oilfields.

The argument may arise that the reinjection temperature in geothermal fields may be even lower than the temperature of many producing oil and gas wells. Therefore, the stimulation fluids used successfully in high temperature oil and gas wells should also be applicable in geothermal reinjection wells with their relatively low wellbore temperatures. The authors feel that this argument is not very well taken. The reasons are fairly simple:

- 1) The rock material, even though cooled by the reinjected brine, was previously under high temperatures and, therefore, has a different composition and reactivity than those in the "high" temperature oil and gas wells.
- 2) The damaging materials found in geothermal reinjection wells are quite different from those experienced in oil and gas producing wells.

The main conclusion drawn by the authors is the fact that little or no information on the reactivity of various potential stimulation fluids with various rock and damaging material retrieved from geothermal reinjection wells is available in the open literature. These data must be obtained in the laboratory within the shortest possible time. These laboratory experiments and data should be considered top priority in evaluating the various types of stimulation fluids available at the present time.

12.3 Proposed Laboratory and Field Experiments for Injection Wellbore Stimulation

A program is required to evaluate:

- 1) Injector wellbore damage

- 2) Potential value of various stimulation fluids in removing this wellbore damage
- 3) Various diagnostic tools to monitor experimental stimulation jobs and to determine the down-hole physical and chemical reactions during and after these experimental jobs
- 4) A number of field stimulation experiments should be performed to develop the required new stimulation technology for geothermal injection wells. Fracturing of wells should be considered but not overemphasized because of the potential dangers involved in this technique. Emphasis should be placed on chemical stimulation techniques.

13.0 PROPOSED PHASE II OF THIS PRESENT STUDY

This present report outlines the major problems encountered and to be expected during the reinjection of geothermal brines. The authors suspect that there may be a number of additional problems not mentioned in this present report. These additional problems must be uncovered in the follow-up work of this study, namely PHASE II.

PHASE II of this present study is mainly concerned with problem solving as opposed to PHASE I (present report) which is concerned with the definition of the problems.

The proposed basic program for PHASE II includes:

- 1) Developing of brine injectability standards with heavy emphasis on particulate monitoring and chemical brine behavior.
- 2) Preventive brine treatments before reinjection to avoid injection wellbore damage.
- 3) Reservoir monitoring and verification techniques using tracers to allow maximum energy recovery from a given reservoir and to prevent temperature damage to the reservoirs.
- 4) Stimulation techniques to increase wellbore injectivity.
- 5) Reservoir pressure maintenance through imported injection water to increase the potential recovery of energy in place and to avoid subsidence problems.

This proposed basic program for PHASE II involves:

- 1) Theoretical evaluations
- 2) Extensive laboratory test work

- 3) Experimental work with brine and surface facilities in various geothermal installations
- 4) Field experiments with a number of geothermal injection wells

The proposed program will find the approval of the private operators of geothermal fields. Oral and written commitments from private operators were obtained to insure the availability of field test sites.

The main problems regarding the execution of PHASE II are expected to be timing and cost. Presently, there are no continuous and routine operations of reinjection wells within the United States. This means, all field work must be tied in with experimental and intermittent operations of injection wells. This may cause timing problems. The cost of PHASE II may be larger than originally assumed by DOE/DGE.

The authors feel that there is only one alternative to avoid problems caused by timing and excessive cost. The proposed PHASE II must be tied into the presently ongoing stimulation program for geothermal producers and reservoirs. This ongoing program is also funded by DOE/DGE (Contract No. DE-AC32-7910563, prime contractor: Republic Geothermal, Inc.). Fortunately, both authors and their respective organizations are participating in this stimulation work of geothermal producing wells. Both authors are principal investigators in the proposed PHASE II of this present study and also in the ongoing stimulation of geothermal producers (Contract No. DE-AC32-7910563).

Many laboratory and field experiments proposed for both studies are very similar in nature and involve similar techniques. The time and cost savings achieved by conducting both studies through the same principal investigators will be substantial and will allow PHASE II of this present study to be conducted within the budget allocated by DOE/DGE.

TABLE 1

SCALE FORMING COMPOUNDS

A. NATURAL

1. SILICA
2. SULFATES ~ Na, Ba, Ca, Mg
3. SULFIDES ~ Fe, Zn, Pb, Cu, Ag, Sb
4. SILICATES
5. CARBONATES ~ Ca, Fe
6. HALIDE
7. MIXED PHASES
8. "EXOTICS I"

B. MAN - MADE

1. SULFATES
2. SILICATES
3. CLAYS
4. SULFIDES ~ As
5. VARIOUS ~ ORGANICS
6. "EXOTICS II"

TABLE 2

IMPORTANT PROPERTIES OF PARTICLES SUSPENDED IN GEOTHERMAL BRINES

- 1.) Particle Geometry**
 - a.) Size**
 - b.) Size Distribution**
 - c.) Shape**
 - d.) Population**
- 2.) Chemical Composition**
- 3.) Density**
- 4.) Optical Properties**
- 5.) Electrical Properties**
- 6.) Rheological Properties**

TABLE 3

PHYSICAL PRINCIPLES EMPLOYED TO SENSE SIZE AND MONITOR SUSPENDED PARTICLES

- 1.) Classification
 - a.) Elutriation
 - b.) Hydrocyclones
 - c.) Sedimentation
- 2.) Fluid Flow Characteristics
 - a.) Permeametry
 - b.) Non-Newtonian Rheological Properties
 - c.) Nozzles
- 3.) Electrical Resistance Changes
- 4.) Image Replication
- 5.) Light Scattering
- 6.) Radiation Attenuation
 - a.) Light
 - b.) Ultrasonic
 - c.) β , γ And X-Ray
- 7.) Hot Wire Anemometry
- 8.) Electrostatic Ion Capture

TABLE 4

DESIRED INSTRUMENTATION PARAMETERS FOR ON-LINE PARTICLE MEASUREMENT

- 1.) Automatic And Continuous Operation
- 2.) Response Time Nearly Instantaneous
- 3.) Accurate And Precise Information
- 4.) Detecting And Measuring Of A Wide Spectrum Of Particle Properties
- 5.) Determine The Shape Factor
- 6.) Operational With Various Particle Concentrations
- 7.) Instrumentation And Sensor Must Be Rugged, Corrosion And Errosion Resistant
- 8.) Must Not Disturb The Flow Pattern Of Particulate And Fluid Phases
- 9.) Low Capital, Operational And Maintenance Cost

TABLE 5

TRACER REQUIREMENT (150 MW GEOTHERMAL POWER PLANT)

ASSUMPTIONS:

- 1.) Reinjection: 1.31×10^8 Lt/Day
- 2.) 10^{-2} % Of Reinjected Brine Must Be Found In Produced Brine
- 3.) Tracer Slug: 24 Hours
- 4.) Analytical Sensitivity:
 - A.) Tritium: 2 DPM/ml
 - B.) Chemical: 1 mg/Lt
- 5.) Cost / Unit:
 - A.) Tritium: \$ 50.-/Curie
 - B.) Chemical: \$ 0.30/Kg

TRACER JOB:

- 1.) Required Amount Of Tracer:
 - A.) Tritium: 2.62×10^{15} DPM = 1178 Curies
 - B.) Chemical: 1.31×10^6 Kg
- 2.) Total Cost Of Tracer:
 - A.) Tritium: \$ 58,900.-
 - B.) Chemical: \$393,000.-

REQUIRED REINJECTION FOR 150 MW GEOTHERMAL POWER PLANT

ASSUMPTIONS:

- 1.) 20 Lbs Steam Per Hour
- 2.) 20 % Flash
- 3.) Density Of Rejected Brine: 1.2 Kg/Lt

REQUIRED REINJECTION:

- 1.) Steam (Not Rejected): $20 \times 150 \times 1000 \times 24 = 7.2 \times 10^7$ Lbs/Day
- 2.) Rejected Brine: $7.2 \times 10^7 \times 4 \times 1.2 = 3.46 \times 10^8$ Lbs/Day
= 1.57×10^8 Kg/Day
= 1.31×10^8 Lt / Day

FLOW RATES OF SUSPENDED AND DISSOLVED SOLIDS

	APPROXIMATELY	
	METRIC TONS PER YEAR	POUNDS PER DAY
MISSISSIPPI RIVER	1.13×10^8	6.82×10^8
1000 MWe* (GEOTHERMAL)	9.77×10^7	6.15×10^8
3000 MWe**(GEOTHERMAL) PROJECTED FOR 1985	2.93×10^8	1.85×10^9
20,000 MWe** (GEOTHERMAL) PROJECTED FOR 2000	1.95×10^9	1.23×10^{10}

* ASSUMING: 1.86×10^9 LITERS OF BRINE PER DAY, 150,000 MG/LITER TDS

** ASSUMING: DOE ESTIMATION IN 1977

TABLE 7

FINANCIAL LOSS DUE TO PREMATURE BREAK-THROUGH

1.) NO PREMATURE BREAK-THROUGH

a.) Calc. Recoverable Reserves:	\$10 ¹⁰ (Assume: 1000 MW; \$ 0.038/KW hr)
b.) Hydraulic Front:	20 Years
c.) Temperature Front:	30 Years

2.) PREMATURE BREAK-THROUGH

Hydraulic Front	Temperature Front	Recoverable Reserves	Non-Recoverable Reserves
20	30	100% = \$ 1.0 x 10 ¹⁰	\$ 0
15	2.5	75% = \$ 7.5 x 10 ⁹	\$ 2.5 x 10 ⁹
10	15.0	50% = \$ 5.0 x 10 ⁹	\$ 5.0 x 10 ⁹
5	7.5	25% = \$ 2.5 x 10 ⁹	\$ 7.5 x 10 ⁹

TABLE 8

IN-SITU DETERMINATION OF Ba^{++} CONCENTRATION THROUGH SPECIFIC CONDUCTIVITY

FIGURE 1

Ag₂S SOLUBILITY

(20 °C; IONIC STRENGTH: 1.0; TOTAL S: 0.02 MOL/L)

FIGURE 2

SYSTEM DIAGRAM FOR BASIC THERMODYNAMIC SCALE RESERVOIR MODEL (VESCAL II)

FIGURE 3

**BASIC THERMODYNAMIC PRECIPITATION SIMULATOR (VESCAL II)
(MIXING OF INCOMPATIBLE WATERS)**

FIGURE 4

SYSTEM DIAGRAM FOR BASIC THERMODYNAMIC SCALE RESERVOIR MODEL (VESCAL I)

FIGURE 5

BASIC THERMODYNAMIC MODEL FOR PREDICTION OF SCALE AND ITS EFFECT ON RESERVOIR (VESCAL I)

FIGURE 6

FIGURE 7

THERMODYNAMIC MODEL FOR FLASH IN $H_2O - CO_2$ SYSTEM

P_i = Partial Pressure Of i^{th} Component

X_i = Mole Fraction Of i^{th} Component In Liquid

Y_i = Mole Fraction Of i^{th} Component In Vapor

$\phi = \frac{U}{F}$ Fraction Of Flash

$\frac{L}{F} = 1 - \phi$

F = Rate Of Feed

L = Rate Of Liquid After The Flash

U = Rate Of Vapor After The Flash

FIGURE 8

CO₂ AND H₂O FLASH IN 64 MW POWER PLANT

FIGURE 9

CO₂, N₂ AND H₂O FLASH IN A 64 MW POWER PLANT

FIGURE 10

CO₂ VENTING IN 64 MW POWER PLANT

FIGURE 11

CO₂ VENTING IN 64 MW POWER PLANT

(FEED : 320 °F; 1070 ppm CO₂ OR 0.00044 MOL CO₂ PER MOL H₂O)

SCHEMATIC DIAGRAM OF SINTERED METAL FILTER ARRANGEMENT

FIGURE 13

FILTER PERMEABILITY:
FILTER I < FILTER II < FILTER III

FILTER ARRANGEMENT TO DECREASE TEMPERATURE LOSS

FIGURE 14

FILTER ARRANGEMENT FOR MINIMUM TEMPERATURE LOSS

FIGURE 15

"EFFICIENCY-TIME" RELATIONSHIP (SAME INHIBITOR AND SCALE; DIFFERENT CONDITIONS)

FIGURE 16

FIGURE 17

WELLBORE MODELING

EXISTING MODELS

VR/PTTS MODEL

FIGURE 18
RESERVOIR SYSTEM

FIGURE 19
RESERVOIR CROSS SECTION

FIGURE 20
RESERVOIR BOUNDARY CONDITIONS

TEMPERATURE CONTOURS

FIGURE 21

TEMPERATURE AND HYDRAULIC FRONT AT A GIVEN TIME

FIGURE 22

STREAMTUBE ELEMENT

FIGURE 23

STREAMTUBE REPRESENTATION

FIGURE 24

DISPLACEMENT OF RESERVOIR WATER BY INJECTION WATER

FIGURE 25

FIGURE 26

MIXING DUE TO VARIATION IN ARRIVAL TIMES OF INJECTION WATER

MIXING THROUGH HORIZONTAL HETEROGENEITIES

FIGURE 27

MIXING THROUGH VERTICAL HETEROGENEITIES

FIGURE 28

MIXING PROBLEMS THROUGH DIFFERENT ARRIVAL TIMES

FIGURE 29

BASIC THERMODYNAMIC MODEL FOR PREDICTION OF SCALE AND ITS EFFECTS ON RESERVOIR (VESCAL III)

FIGURE 30

PARTICLE SIZE DISTRIBUTION

FIGURE 31

DEFINITION OF PERMEABILITY VARIATION FACTOR

FIGURE 32

FIGURE 33

LAYERING IN RESERVOIR SECTION

VARIATION OF FILTER CAKE THICKNESS AND kh PRODUCTS

FIGURE 34

**INJECTIVITY DECLINE FOR GIVEN RESERVOIR
GEOMETRY (r_D) AND PARTICLE DISTRIBUTION (N)**

FIGURE 35

FLOW DETERMINATIONS BY RA TRACERS

FIGURE 36

UR

TRACER BREAK-THROUGH DATA
(TYPICAL ELUTION CURVES IN WELL TO WELL TRACING)

FIGURE 37

TRACER SELECTION FOR FIELD WITH GEOMETRIC WELL PATTERN

○=INJECTION WELL

●= PRODUCTION WELL

CHOICE I (1 TRACER)

CHOICE II (9 TRACERS)

CHOICE III (18 TRACERS)

CHOICE IV (10 TRACERS)

FIGURE 38

DUAL TRACER ELUTION PROFILE

FIGURE 39

TYPES OF ADSORPTION ISOTHERMS (LIQUID - SOLID SYSTEMS)

FIGURE 40

ADSORPTION ISOTHERMS

FIGURE 41

**DUAL TRACER ELUTION PROFILE FROM THREE DIFFERENT FRACTURES
(SAME FRACTURE CONDUCTIVITY DIFFERENT PATH LENGTHS)**

FIGURE 42

BASIC MECHANISMS OF A SQUEEZE

(DUAL ISOTOPE METHOD)

FIGURE 43

→ ppm

→ DAYS

UR

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APPENDIX

THE PREDICTION OF SCALE PROBLEMS DUE TO INJECTION OF INCOMPATIBLE WATERS

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ABSTRACT

Prediction methods for chemical water compatibilities in waterflood operations are described. Injecting of water incompatible with the reservoir water can lead to major production problems during the flood depending upon the water compositions, degree of mixing, pressures and temperatures.

Various types of calculations to predict precipitations of scale-forming compounds are outlined. VESCAL II uses a comprehensive data base of actually measured solubilities in fairly complex oilfield and geothermal brines at various temperatures but low pressures. The pressure effects on the solubilities and precipitations are calculated. First, the precipitation of the most insoluble salt (e.g., BaSO_4) is computed. Then, the precipitation of the next most insoluble salt (e.g., SrSO_4) is calculated. This will remove more common ions from the solution than assumed in the first calculation of the most insoluble salt (e.g., BaSO_4). Next, some of the previously precipitated salt is redissolved until both salts are in thermodynamic equilibrium with the resulting solution. This entire process is repeated for all salts which will precipitate under the given conditions. VESCAL II will automatically calculate the amount of precipitation (scale) formed in various locations such as reservoir, skin, wellbore and surface equipment.

The model has been used to calculate the coprecipitations of BaSO_4 , SrSO_4 and CaSO_4 by mixing of two different injection waters with two different reservoir waters under an assumed set of field conditions. The results of these calculations using VESCAL II are compared with the values resulting from a previously used model.

INTRODUCTION

Two of the more difficult problems in designing a proper waterflood operation are: (1) The predetermination of chemical incompatibilities of the waters used in the flood and (2) the forecast of these incompatibility effects on future field operations. This

forecast should cover the type, extent and location of all future damages due to chemical incompatibility problems.

No damage of any kind would occur if all reservoir materials were chemically compatible with the injected water. However, hardly any source water available in large enough quantities is fully compatible with all materials in the reservoir to be flooded.

The water native to the reservoir to be flooded is in chemical equilibrium with the rock, the hydrocarbons and any other materials present in the reservoir (e.g., CO_2 , N_2 , H_2S , etc.). In contrast, the water considered for injection was in equilibrium with its own environment which is normally quite different from that in the reservoir to be flooded. Any injection automatically leads to a readjustment of most chemical parameters as soon as the injection water enters the reservoir. The newly injected water must reestablish its own and new thermodynamic equilibrium with respect to all solids and fluids present in the reservoir to be flooded.

In conventional reservoir engineering and waterflood design, the fluids and rock phases are considered to be chemically inert, i.e., these liquid, gaseous and solid phases have physical properties which can have large effects on the flow properties but which do not actively participate in any chemical reaction. In reality, this is not true at all. Any injected water having an origin different from the reservoir to be flooded will chemically interact with the fluids and solids in the flooded reservoir. These interactions, of course, will depend upon the chemical compositions of all participants in these interactions (liquid, gaseous and solid phases), the degree of mixing, the flow paths, and the temperatures and pressures at various locations within the flooded reservoir.

To complicate the situation even further, the reservoir water (i.e., the produced water) may be produced at thermodynamic conditions again different from those within the reservoir. For example, dissolved CO_2 and H_2S may break out of solution when the water is produced together with the hydrocarbons. This loss of reactive gases will change the composition and pH

References and illustrations at end of paper.

of the water, thus generating a possible compatibility problem when the produced water is reinjected. This means, compatibility problems can occur, at least theoretically, even during reinjection of produced water originating in the reservoir to be flooded.

Ignoring the chemical reactions between injected waters and reservoir materials can lead to the disasters often experienced in the field. The formation of scale in the producing wells is the most obvious result of the frequently encountered compatibility problems. In this paper we describe some of the pre-flood considerations necessary for a proper flood design. Basic model considerations are presented which allow one to forecast many of the scale problems due to the injection of incompatible waters. An attempt is made to forecast the location and extent of various damages due to scale formation. The model or precipitation simulator (VESCAL II) is based on thermodynamics only. Time elements, i.e., reaction kinetics, are not considered in this paper; they are subject to further scale model development.

THE PREDICTION OF SCALE PROBLEMS DUE TO INJECTION OF INCOMPATIBLE WATERS

Quite frequently, waterfloods are started up without considering the resulting scale problems. The main reason for "ignoring" the potential scale problems is the lack of an accurate model to predict the scale problems stemming from the incompatibility of the injected water with the native reservoir materials. Thus, waterflood operations are frequently started without a proper risk analysis.

The literature contains an extremely large number of references describing the formation of major oil-field scales as a function of various water compositions and thermodynamic conditions.^{1,2,3,4} However, none of the available "scale prediction methods" is suited for the evaluation of water compatibility problems encountered in a large-scale waterflood. Presently known "scale prediction models" have major shortcomings which make them unsuitable for a thorough and accurate evaluation of all scale problems to be expected in a waterflood.^{5,6}

What is needed is a new model that takes into account the major parameters leading to scale formation at various locations within the reservoir, wells and surface equipment. This model must consider all possible water compositions before, during and after mixing of the various aqueous phases in any field location during flood operations. It must also include the very site-specific pressure and temperature histories of various points within the reservoir, wells and surface equipment. Finally, this model must also accommodate the various changes of the many parameters leading to damage by scale formation over the entire life of the flood.

A newly developed model (VESCAL II) and one of its applications is described below. The model has been used for the prediction of three different sulfate scales: BaSO₄, SrSO₄, and CaSO₄. Subroutines for other types of scales such as carbonates or sulfides can easily be added.

The water compositions and field conditions described in this paper are fictitious and have been chosen so as to illustrate the type of considerations necessary for the evaluation of water compatibility problems.

ACCURATE WATER ANALYSES COME FIRST

Accurate chemical analyses of all waters produced and considered for injection are of prime importance. This may sound trivial. However, experience in many fields has shown that water analyses are sometimes difficult to perform and quite often, the reported data show extreme inconsistencies. A recent research study supported by the U.S. Department of Energy has shown that even well-equipped laboratories using very sophisticated analytical techniques are quite error-prone if these laboratories do not specialize in water analyses.⁷ Only experienced laboratories using modern equipment and techniques should be used for the analytical work prior to the application of any precipitation simulator and comprehensive scale prediction. All necessary analytical data must be measured. Calculating the concentration of various components (e.g., Na⁺) should not be allowed.

Collecting proper water and gas samples is another major problem directly related to the precise analytical determination of the water compositions. The use of correct sampling methods becomes of extreme importance when it comes to the prediction of carbonate and sulfide scale problems.^{7,8}

Any error in determining the correct water compositions will be carried throughout the calculations and can lead to quite erroneous results of any incompatibility or scale prediction.

PREVIOUS SCALE PREDICTION AND ITS SHORTCOMINGS

In previous papers,^{5,6} the major problems of modeling the scale formation in subterranean reservoirs have been outlined. Even the prediction of single component scales^{2,3} has many shortcomings.

Most of the previously and presently used scale prediction models are more or less proprietary and are not referenced in this paper. Many of these prediction methods ignore the extremely critical effect of pressure on the scale formation.⁹⁻¹³ Others, including two published treatments by one of the authors,^{5,6} do not consider the problems caused by the simultaneous precipitation of scale-forming compounds containing more than one scale component. These are scales with common ions such as CaSO₄/SrSO₄/BaSO₄ or CaCO₃/SrCO₃/FeCO₃ or CaCO₃/CaSO₄. For example, BaSO₄ having normally the smallest solubility product (K_{sp}) of the three sulfates (CaSO₄/SrSO₄/BaSO₄) will precipitate first, thus partially removing some of the sulfate ions from the solution during the BaSO₄ precipitation. Ignoring this resulting decrease of the sulfate ion concentration in calculating the ionic products for the subsequent CaSO₄ and SrSO₄ precipitations will result in large errors throughout the entire scale prediction. Figure 1 illustrates this common but basically wrong approach.

A great improvement is achieved when the precipitation of the various sulfates is not considered to take place simultaneously and independently as shown in Figure 1 but sequentially as shown in Figure 2.

The scale component having the smallest K_{sp} (e.g., BaSO₄) precipitates first, thus removing some SO₄²⁻ ions from the solution. This precipitation of BaSO₄ is followed by the precipitation of the second component having the next larger K_{sp} (e.g., SrSO₄). The ionic product required for calculating this new

precipitation is adjusted for the previous BaSO_4 precipitation. Finally, the last component of this series (CaSO_4) will precipitate. Here again, the composition of the solution will be adjusted before the CaSO_4 precipitation occurs but after the BaSO_4 and SrSO_4 precipitations have taken place. The entire process is repeated for each set of thermodynamic conditions at which any precipitation can occur.

Even though this improved model can be used successfully in some instances, it is not generally applicable. In nature, the scale components do not precipitate sequentially and independently of each other but more or less simultaneously particularly at higher degrees of supersaturation. In nature, the concentration of the common ion and with that the true amount of scale per liter of solution is automatically and instantaneously adjusted during all precipitation reactions. This adjustment must be accomplished in any precipitation simulator to duplicate mathematically the natural phenomenon.

The improved version of a scale prediction model (see Figure 2) allows only a limited degree of adjustment. If the K_{sp} value of one precipitate (e.g., CaSO_4) is fairly small and the K_{sp} value of the other precipitate is even smaller by an order of magnitude (e.g., BaSO_4) the principal errors of this method may be small and tolerable. However, if the difference between the K_{sp} values becomes fairly small, e.g., by introducing SrSO_4 into the $\text{BaSO}_4/\text{CaSO}_4$ system, and/or if more than two scales can form out of the same water, the errors become large and intolerable. Therefore, a series of new scale prediction models was developed. The VESCAL II precipitation simulator is only one of these models.

THE SCALE PREDICTION MODEL OR PRECIPITATION SIMULATOR VESCAL II

VESCAL II will predict precipitation rates of scale-forming compounds as a function of:

- 1) Mixing ratios of various waters.
- 2) Compositions of source (injection) and reservoir waters.
- 3) Temperatures at any point or location in the field.
- 4) Pressures at any point or location in the field.

The basic model VESCAL II is described in Figure 3. This simulator will first determine how much precipitate will be formed if two incompatible waters having a given (measured) composition are mixed under a given set of field conditions. These field conditions include temperature, pressure and mixing ratio at the locations of mixing the two waters. After calculating the amount of precipitation per liter of mixture (of the two waters), the simulator calculates the composition of the remaining clear water. As this remaining clear water moves to a location having a different set of thermodynamic conditions (pressure and temperature) the simulator will now calculate how much new precipitate will form in the new location. It will also calculate the composition of the remaining solution after this second precipitation occurs. Then, this remaining water is moved again to a location with different pressures and temperatures where the entire process is repeated. This cycle is repeat-

ed until, finally, the remaining water will be moved to a location where no further changes of the thermodynamic conditions occur or where the remaining water is either reinjected or mixed with a different type of water. If mixing with a different type of water is performed, the simulator stops. It can be started again with the composition of the new waters (which are now mixtures if this new water is reinjected) as the required input information.

The pressures in the field may vary greatly with the location (see Figure 4). Each time a pressure and/or a temperature change is indicated anywhere in the field, the simulator will automatically start a new calculation cycle for any of these changes.

This simulator (VESCAL II) does not calculate ionic products and solubilities based on fundamental thermodynamic quantities or functions such as free energies, enthalpies, etc. This has been tried before with many problems and with extremely little success. In order to calculate solubilities based on basic thermodynamic functions, one must have access to measured basic data and then calculate the actual ion activities. This can be done by using specially developed codes for calculating activity coefficients.¹⁴ The previously-mentioned codes⁸⁻¹³ use this type of computational method. One of these codes¹⁰ takes an extremely long computational time and calculates a great number of different kinds of scale without taking the pressure effects into account. The other code⁹ requires even larger computational power and times. Both codes were developed for geological situations and will predict many precipitations and scale formations in oil and gas fields that will have very little effect on the well productivity or formation damage. Ignoring the pressure effects, of course, will not permit one to predict skin and many wellbore damages due to scales which are formed by pressure drops at constant temperatures. These scales normally form the most severe wellbore and formation damages.

VESCAL II uses a totally different, more practical approach. This simulator is not tailored to geological considerations but to oilfield and geothermal field operations where large pressure and temperature drops can occur within fairly short times. Large pressure drops on the order of 10 to hundreds of atmospheres can occur within hours or days.

VESCAL II works with ion concentrations and not with activities. This may sound surprising and non-scientific. However, the data base used for VESCAL II contains actually measured saturation concentrations (solubilities) of the scale-forming salts at various temperatures in solutions containing the various major components of oilfield and geothermal brines. Any entry into the data base comes either from the open literature or is generated in the laboratory using radioactive tracers for precise solubility measurements. Data from the open literature are constantly verified and gaps in the data base are constantly filled. Some applications of VESCAL II may require the filling of small gaps in the measured solubilities. This can normally be accomplished within one to four weeks in the laboratory. The present data base is nearly complete for major oilfield scales, thus decreasing the required laboratory work for each consecutive application of the simulator.

The measured solubilities as a function of temperature and ionic composition of the aqueous solutions contain the activities. This eliminates

the need for complicated, time-consuming and error-prone activity calculations.

VESCAL II calculates first the "corrected" NaCl concentration of any mixture of two waters. The data base takes into account that the solubility of many scale-forming compounds at a given temperature but at low pressure (1 atmosphere up to 100°C and steam saturation pressure at temperatures larger than 100°C) is not simply a function of the true NaCl concentration. On the other hand, this solubility is also not a function of the "total ionic strength" as assumed in other codes^{9,10} but it is a function of the complex chemical composition of the brine. This has been shown by Davis and Collins¹⁵ and is also indicated in our own laboratory studies.¹⁶ This means, not the ionic strength but the actual chemical composition of the solution (water) determines the solubilities of sparingly soluble salts. Presently accepted theories on thermodynamics often contradict these actually measured data and assume that the total ionic strength determines the solubility. The main reason why we do not trust this theory is the commonly made assumption that none of the ions in solution (commonly present in oilfield brines) can form complexes (coordination compounds) of unknown composition. This means, if basic thermodynamic functions are used and unknown complexes exist in solution, the codes will predict precipitations quite different from those measured in the actual solubility studies predicted by VESCAL II and often experienced in the field.

The most critical portion of VESCAL II (see Figure 3) is the Subroutine ADJ. Other codes using basic thermodynamic functions may utilize a questionable approach to accommodate the simultaneous precipitation of more than one salt having a common ion (e.g., BaSO₄/SrSO₄/CaSO₄). These codes contain a subroutine which calculates a minimum of the free energy of the entire system at which all precipitations stop. Here again, this would be correct if the free energies of all the compounds (including complexes) were known. In addition, the computational power required for this subroutine is considerable, thus boosting the cost for each run of such a code. This means, running one of these codes not only may give erroneous predictions, it may also be very costly.

VESCAL II uses again a different approach. It first calculates the amount of scale for the salt having the lowest solubility product (e.g., BaSO₄). Because sulfate ion has been removed from solution, the calculations of SrSO₄ and CaSO₄ precipitations are thrown "out of balance". This is corrected by adjusting the concentration by redissolution of some BaSO₄ to account for ions lost from solution. New ionic products and solubilities are now calculated. The entire process is repeated and continuous redissolution and precipitation of all scale-forming compounds (BaSO₄, SrSO₄, and CaSO₄) is taken into consideration until the correct balance is approached. By using an iteration technique to calculate precipitations and dissolution until the ratios of K_{sp} to K_{sp} become constant and equal for all three compounds (BaSO₄, SrSO₄, and CaSO₄), the precise and correct balance is achieved.

USE OF VESCAL II IN A SPECIFIC EXAMPLE

To illustrate the power and workability of VESCAL II, the results of an actual sample calculation are presented below. The assumed water compositions are given in Table 1:

- 1) Reservoir water No. 1
- 2) Reservoir water No. 2
- 3) Source water No. 1
- 4) Source water No. 2

The corresponding ionic composition of these four waters are given in Table 2. The only difference between the two reservoir waters is their CaCl₂ content (see Table 1). This is reflected in the Ca⁺⁺ and Cl⁻ ion composition of the two waters (see Table 2). The analyses of the four different waters show immediately that both injection waters are highly incompatible with both reservoir waters. Heavy scale formation can be expected if any of the two source waters is injected into any of the two reservoirs.

A waterflood is to be started in both reservoirs containing "reservoir water No. 1" and "reservoir water No. 2". The pertinent pressures and temperatures of the field are given in Table 3. Only the two described source waters are available for flooding the reservoirs No. 1 and No. 2. The questions are:

- 1) Where and to what extent can one expect major scale problems in the field by using either one of the two source waters in either one of the two reservoirs?
- 2) Which one of the two source waters is more suitable for injection into any of the two reservoirs?

The General Idea of Damage Prediction.

In order to predict the various types of potential damages, both source waters (injection waters) are combined with either one of the two reservoir waters in various proportions. The general idea is that any injection water will eventually become mixed with the reservoir water at any proportion at various locations in the field.

The first problem arising is the determination of the location where this mixing will occur. Various types of mixing of the two waters (injection and reservoir water) can occur practically anywhere in any location in the field. Depending upon the heterogeneities in the reservoir, the mixing can be expected in the reservoir, skin, wellbore or surface equipment. This degree of mixing and the location of mixing will have a pronounced effect on the degree and location of damage.

The effects of different arrival times of injection waters (homogeneous reservoir) and of the reservoir heterogeneities (vertical and horizontal such as high permeability streaks and fractures) will be described in a future publication. In this present paper, we describe only the scale prediction in an isotropic reservoir.

It is assumed that mixing of the injection and reservoir waters starts at the injection wellbore and will be completed in the reservoir.

Upon mixing, the first scale will form due to the incompatibility of the two waters under reservoir conditions (pressure and temperature). After precipitating the various types of scale-forming solids,

the now saturated mixtures will flow toward the producing wells. The pressure will constantly drop as the saturated mixture approaches the producing well. A drastic pressure drop will occur close to the sand-face of the producer. This pressure drop (see Table 3) will have a pronounced effect on the solubility of the various scale-forming compounds in the saturated mixture. As a result, more salt will precipitate and a skin will form.^{2,3} This means, the mixtures of injection and reservoir water will be even more depleted in their content of scale-forming compounds.

These partially depleted mixtures now enter the wellbore and flow toward the surface. In this process, the pressure will drop even further. At the same time, a temperature decrease will be experienced. Consequently, more scale may form in the wellbore, thus further depleting the mixtures in their potential tendency to form scale.

Finally, the resulting mixtures flow through the X-mas tree into the surface facilities. Here again, pressure and temperature decreases (see Table 3) may cause the formation of more scale.

The approach taken in this paper is straight forward. The old prediction model (see Figure 2) and the new model (VESCAL II, see Figure 3) are rigorously applied for the various mixtures of the two injection and two reservoir waters for the four distinct locations in the field. All data are plotted in Figures 5-20.

Reservoir Scale Prediction.

The numerical data obtained from the various computer runs using conditions outlined in Tables 2 and 3 and the two injection and reservoir waters are plotted in Figures 5 to 7. The solid symbols represent the data obtained by using VESCAL II, whereas the open symbols show the data obtained by applying the old prediction model (see Figure 2).

Most of the scale will form in the reservoir no matter which one of the two source waters is injected into either one of the two reservoirs. It must be noted that source water No. 1 causes more reservoir scale than source water No. 2 in either reservoir; Figures 9 and 11 show a different scale on the ordinate than Figures 10 and 12!

It is interesting to note that the predictions deviate from each other to various degrees using either one of the two methods depending upon the original water compositions. Both methods show almost identical results if source water No. 2 is injected into reservoir No. 2 (see Figure 8). However, there are some important differences in the predicted scale formation using the other injection/reservoir combinations. Both prediction methods yield almost identical BaSO_4 data in all four cases which was expected. The largest and most important deviations occur in the SrSO_4 prediction (see Figures 5 and 6). VESCAL II predicts much less SrSO_4 scale in the reservoir than the old method. This can be theoretically explained.

Skin Formation.

Figures 9-12 show the composition of the scale in the skin. Source water No. 1 and reservoir No. 1 (Figure 9) shows no BaSO_4 or SrSO_4 precipitations in

the skin. Only CaSO_4 precipitates in this location. Source water No. 1 and reservoir No. 2 will also generate an almost pure CaSO_4 skin according to the data obtained by using VESCAL II. The old method predicts also a SrSO_4 skin. SrSO_4 and CaSO_4 skins are predicted for the remaining source water/reservoir combinations (see Figures 11 and 12).

The "amazing" fact is that none of the source water/reservoir combinations show any BaSO_4 skin. This is a critical factor for actual field operations. Scale inhibitors and wellbore stimulations must be based upon the type of scale and the scale tendency. The new predictions, therefore, will suggest a totally different type work-over and scale inhibition program than previously recommended.

Scale Prediction for Wellbores.

Figures 13-16 show the scale prediction for the producing wellbores. Both old and new prediction methods show almost identical results: Only BaSO_4 scale will be formed. We can think of water compositions (source or reservoir waters) where multi-component scale can be formed in the wellbores. However, the composition of the chosen waters (see Tables 1 and 2) are so that (a) only BaSO_4 forms and (b) both prediction methods yield more or less accidentally the same data.

The predicted data shown in Figures 13-16 illustrate one of the "pitfalls for the unwary". Any solid samples retrieved from these wellbores would have indicated only BaSO_4 scale. The conclusion of the unwary operator could have been, that only BaSO_4 scale is his problem in the reservoir and skin. Any selection of stimulation and scale inhibitor methods would have been based on the wrong conclusion.

Scale Prediction for Surface Equipment.

Figures 17-20 show the predicted data for the surface equipment. Here again, only BaSO_4 will precipitate in the equipment. A situation similar to that described for the wellbores will exist in the surface equipment (see previous paragraph).

Injection Water No. 2 Offers Only Slight Benefits Over Injection Water No. 1.

The formation of reservoir scale per se does not mean that an incompatible water is unfit for injection purposes. The precipitation of solids and the resulting plugging in high permeability streaks may even show some beneficial effects on the sweep efficiency. In a sense, one can consider this scale formation as a tertiary oil recovery process.

The critical problem starts with the formation of a skin in the producing wells. Skin formation by scale is one of the most annoying effects encountered in daily routine operations of waterfloods.

Two factors are most important for any evaluation of this type of scale:

- 1) The type of scale formed in the skin.
- 2) The amount of scale formed per volume unit of produced fluid.

Judging from the data plotted in Figures 9-12,

injection water No. 1 causes more skin damage in either reservoir than injection water No. 2. However, the differences in expected skin damage are only minor despite the large differences in the original water compositions (see Tables 1 and 2). This may be surprising. However, these small differences in skin damage can be explained by the fact that both injection waters have lost most of their scale-forming power in the reservoir.

Based on the type of scale in the skin, injection water No. 1 is actually more suitable for injection because only CaSO_4 scale will form in the skin. This scale can easily be removed chemically, thus providing a chance for effective stimulation methods. A SrSO_4 skin is formed with injection water No. 2 which is much harder to remove.

The scale formation in the wellbore and surface equipment is approximately equal in type and rate for all source water/reservoir combinations.

CONCLUSIONS

- 1) A new scale prediction model has been developed. This new model (VESCAL II) can be applied to predict scale precipitations in waterflood operations. Water compositions, pressures and temperatures are taken into account.
- 2) The new model (VESCAL II) allows a more reliable damage forecast than an older model. In some instances, the results obtained by using both models do not differ very much. In some other instances, the deviations can be critical.
- 3) A comparison between the old and new model has been performed by using two different injection waters and two different reservoir waters.
- 4) Application of the new model has shown that various types of scale can form in different field locations. It is not possible to collect solid samples in surface equipment or producing wellbores and draw any conclusions regarding scale in the reservoir or skin based on these collected samples.
- 5) The new model (VESCAL II) calculates the precipitation of scale-forming compounds under the most pertinent field conditions.
- 6) The amount of precipitate formed under field conditions will greatly depend on the mixing ratio. As a "rule of thumb", the formation of scale depends upon the concentration of injection water in the produced fluid. The scale formation rate and the composition of the scale will vary greatly and predictably as more and more injection water is produced.

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TABLE 1

WATER COMPOSITION USED FOR MODEL CALCULATIONS
(IN MG/LITER)

WATER COMPONENT	RESERVOIR WATER		SOURCE WATER	
	NO. 1	NO. 2	NO. 1	NO. 2
NAHCO ₃	500	500	1000	200
NaCl	250000	250000	180000	1000
Na ₂ SO ₄	<1.0	<1.0	3000	1000
KCl	1000	1000	<1.0	<1.0
MgCl ₂	2000	2000	1500	500
MgSO ₄	<1.0	<1.0	400	300
CaCl ₂	60000	6000	5000	800
SrCl ₂	2000	2000	<1.0	<1.0
BaCl ₂	750	750	<1.0	<1.0
FeCl ₂	1100	1100	<1.0	<1.0

TABLE 2

WATER ANALYSES USED FOR MODEL CALCULATIONS
(IN MG/LITER)

WATER COMPONENT	RESERVOIR WATER		SOURCE WATERS	
	NO. 1	NO. 2	NO. 1	NO. 2
Na ⁺	98512	98512	72076	772
K ⁺	524	524	<.5	<.5
Mg ⁺⁺	511	511	464	188
Ca ⁺⁺	21663	2166	1805	289
Sr ⁺⁺	1106	1106	<.5	<.5
Ba ⁺⁺	495	495	<.7	<.7
Fe ⁺⁺	485	485	<.5	<.5
Cl ⁻	192190	159276	113483	1490
SO ₄ ⁻⁻	<1.5	<1.5	2348	915
HCO ₃ ⁻	363	363	726	145.2
PH (RESERVOIR)	6.5		6.5	6.8
PH (SURFACE)	4.1		7.5	7.2

TABLE 3

PRESSURE AND TEMPERATURE
CONDITIONS IN FIELD

STATIC RESERVOIR PRESSURE	200 ATM
FLOWING BOTTOMHOLE PRESSURE	160 ATM
FLOWING WELLHEAD PRESSURE	10 ATM
SURFACE FACILITY PRESSURE	1 ATM
RESERVOIR TEMPERATURE	100°C
BOTTOMHOLE TEMPERATURE	100°C
WELLHEAD TEMPERATURE	70°C
LOWEST TEMPERATURE IN SURFACE FACILITIES	25°C

PREVIOUS SCALE PREDICTION MODEL (MULTIPLE COMPONENT SCALE WITH COMMON ANION)

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FIGURE 1

FIGURE 2

IMPROVED SCALE PREDICTION MODEL
(MULTIPLE COMPONENT SCALE WITH COMMON ANION)

UR

BASIC THERMODYNAMIC PRECIPITATION SIMULATOR (VESCAL II) (MIXING OF INCOMPATIBLE WATERS)

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FIGURE 3

PRESSURE HISTORY IN WATERFLOOD OPERATIONS

FIGURE 4

FIGURE 5

SCALE PREDICTION FOR RESERVOIR (RESERVOIR NO. 1/INJECTOR NO. 1)

FIGURE 6

SCALE PREDICTION FOR RESERVOIR (RESERVOIR NO. 1/INJECTOR NO. 2)

FIGURE 7

SCALE PREDICTION FOR RESERVOIR (RESERVOIR NO. 2/INJECTOR NO. 1)

FIGURE 8

SCALE PREDICTION FOR RESERVOIR (RESERVOIR NO. 2/INJECTOR NO. 2)

FIGURE 9

SCALE PREDICTION FOR SKIN (RESERVOIR NO. 1/INJECTOR NO. 1)

FIGURE 10

SCALE PREDICTION FOR SKIN (RESERVOIR NO. 1/INJECTOR NO. 2)

FIGURE 11

SCALE PREDICTION FOR SKIN (RESERVOIR NO. 2/INJECTOR NO. 1)

FIGURE 12

SCALE PREDICTION FOR SKIN

(RESERVOIR NO. 2/INJECTOR NO. 2)

FIGURE 13

SCALE PREDICTION FOR WELL BORE (RESERVOIR NO. 1/INJECTOR NO. 1)

FIGURE 14

SCALE PREDICTION FOR WELL BORE (RESERVOIR NO. 1/INJECTOR NO. 2)

FIGURE 15

SCALE PREDICTION FOR WELLBORE (RESERVOIR NO. 2/INJECTOR NO. 1)

FIGURE 16

SCALE PREDICTION FOR WELL BORE (RESERVOIR NO. 2/INJECTOR NO. 2)

FIGURE 17

SCALE PREDICTION FOR SURFACE EQUIPMENT (RESERVOIR NO. 1/INJECTOR NO. 1)

FIGURE 18

SCALE PREDICTION FOR SURFACE EQUIPMENT (RESERVOIR NO. 1/INJECTOR NO. 2)

FIGURE 19

SCALE PREDICTION FOR SURFACE EQUIPMENT

(RESERVOIR NO. 2/INJECTOR NO. 1)

FIGURE 20

SCALE PREDICTION FOR SURFACE EQUIPMENT

(RESERVOIR NO. 2/INJECTOR NO. 2)