

Innovative MIOR Process Utilizing Indigenous Reservoir Constituents

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ABSTRACT

This research program was directed at improving the knowledge of reservoir ecology and developing practical microbial solutions and technologies for improving oil production. The goal was to identify and utilize indigenous microbial populations which can produce beneficial metabolic products and develop a methodology to stimulate those select microbes with nutrient amendments to increase oil recovery. This microbial technology has the capability of producing multiple oil-releasing agents.

Experimental laboratory work in model sandpack cores was conducted using microbial cultures isolated from produced water samples. Comparative laboratory studies demonstrating in situ production of microbial products as oil recovery agents were conducted in sand packs with natural field waters using cultures and conditions representative of oil reservoirs. Increased oil recovery in multiple model sandpack systems was achieved and the technology and results were verified by successful field studies.

Direct application of the research results has lead to the development of a feasible, practical, successful, and cost-effective technology which increases oil recovery. This technology is now being commercialized and applied in numerous field projects to increase oil recovery. Two field applications of the developed technology reported production increases of 21% and 24% in oil recovery.

EXECUTIVE SUMMARY

This project was an experimental laboratory and field study designed to improve the understanding of reservoir ecology, and to establish methods of manipulating indigenous microorganisms that utilize naturally occurring water soluble organic acids in the reservoir to produce beneficial oil recovery agents. The objectives of this research program were to demonstrate in-situ production of oil recovery agents in reservoir waters by indigenous microbial populations, and to enhance and control the content and concentration of the bioproducts by the selective addition of low concentrations of inorganic salts as an alternate electron acceptor system. The described research project was designed as a three-year experimental study starting October 1, 1999. A one-year, no-cost extension was granted on the project to continue data collection on the field projects.

The research program centered on the development of a defined microbial system that could function at realistic reservoir conditions for a large number of oil fields which are potential candidates suitable for microbial oil recovery technology. Laboratory conditions were established which were designed to mimic expected conditions in the reservoir and to reduce the need for expensive nutrient additions. This goal of developing a feasible, practical, and cost-effective technology for increasing oil recovery was pursued through the laboratory phase of the investigations and the results were verified by application of the developed technology in field tests.

The research program was divided into a series of tasks that were designed to determine the feasibility of developing an effective in-situ microbial system for increasing the effectiveness of oil-recovery agents in oil reservoirs. Research in this program was focused on stimulating in situ microbial products and metabolic processes to enhance oil recovery. Experimental work on the project began in Task 1 with selection of suitable microbial strains and development of test procedures for subsequent studies. Samples of produced water were obtained from actively producing fields and enriched for selective microorganisms. Several promising strains of microbes were isolated and were used for experimental work. Microcosm scale sand-packed columns were designed and tested for developing selected cultures by nutrient stimulation. Experimental design of flooding regimes was conducted to test the effects of nutrient stimulation on oil recovery in physical models. Research in Task 2 has developed physical models which have been used to quantify improved oil production in porous media. The objective of Task 3 was to demonstrate that nutrient amendments can be used to selectively stimulate microbes to produce oil-releasing agents. Results from Tasks 1 through 3 were applied to Task 4 for inclusion into an increased oil recovery system for field testing which comprised a significant portion of the test program and involved demonstrating and optimizing the effectiveness of the oil recovery biosystem. Data from experimental work has been correlated and integrated for the effects of the biosystems on oil recovery and reported in a form for technology transfer to the oil industry for commercial applications. Work was directed toward applying the new technology to field studies, situations, and operations. This approach provided rapid introduction and evaluation of technology developed by this program.

The laboratory investigations successfully demonstrated that significant increased oil recovery could be achieved by a technology which manipulated the reservoir ecology through the use of

an introduced alternate electron acceptor inorganic salt which complemented the naturally occurring water soluble volatile fatty acids present in the reservoir waters. The new and predominant microbial population developed from the indigenous microflora was established which efficiently and effectively produced multiple products which enhanced oil recovery. The laboratory data were verified by field projects, which utilized the technology developed and which resulted in reported increased oil production in two oil fields of 21% and 24%. This technology has been transferred to the oil industry by multiple presentations and has resulted in its acceptance as a commercial oil recovery technology. Numerous field projects are now ongoing which confirm the success of the technology as an oil recovery process.

Introduction

It was first credited to Beckman in 1926 that microorganisms can survive and multiply in and under reservoir conditions, and have the potential to significantly influence oil practices and production. It has been proposed by many investigators^{1,2} that microorganisms can definitely exert a powerfully positive effect on oil production, especially trapped residual oil. In spite of numerous investigations and field studies³ which report successful results, the application of Microbial Enhanced Oil Recovery (MEOR) technology has not become a widely accepted and practiced oil recovery methodology by the oil industry. The objective of this investigation was to develop and demonstrate a new technology which had the potential to significantly increase oil recovery and which would be accepted by the oil industry due to its practical, cost-effective, and demonstrable effects.

In this investigation, reservoir microflora were deliberately manipulated and controlled by means of specific nutrient amendments to demonstrate increased mobilization and production of oil in laboratory sand packs. Oil release and recovery occurs through the dynamic in situ interactions of reservoir oil/water constituents by targeted indigenous microbes and the production of microbial metabolic reactions and byproducts such as N₂ and CO₂ gases, biopolymers, surfactants, and solvents derived from nutrient utilization.

It has been shown that the introduction and presence of inorganic nutrients can control reservoir ecology, and that adding such nutrients as alternate electron acceptors can stimulate distinct groups of bacteria⁴⁻⁷. Several discoveries resulting from our pioneering work, which lead to an understanding of altered reservoir ecology to control, reduce, and prevent the formation of biogenic sulfide by sulfate reducing bacteria, were of key importance for the present research project.⁸⁻¹² This work also addressed questions which had been a concern on previous MEOR projects.¹³ The basis of this new microbial oil recovery technology is:

1. The presence of volatile fatty acids (VFA) such as acetate, which are naturally present in reservoir brines, supplies the necessary carbon energy source for many indigenous reservoir microbial populations.
2. Low concentrations of selected nitrogen salts stimulate populations of indigenous denitrifying microbes,
3. Such expanded denitrifying populations are heterotrophs known to produce copious amounts of oil-mobilizing chemicals and gases at reservoir conditions,
4. These beneficial microbial populations can be established and maintained within the reservoir by various application protocols involving the use of low-cost nitrogen salt formulae.

Although the present research began using so-called light oils, i.e., oil in excess of 20° API gravity, an opportunity to secure oil and water samples from a well known California heavy oil

field also presented itself early on in the program. Thus, the original line of investigation was expanded in the present research program to include:

1. An increased understanding of the methodology to use low-cost inorganic nutrient amendments that stimulate indigenous beneficial microflora to utilize natural reservoir constituents and cause the release of trapped residual oil, and,
2. To conduct laboratory bench top experiments to determine if trapped 13° API gravity residual oil could similarly be mobilized for production by microbial mechanisms and byproducts that are the result of innovative low-cost nutrient amendments.
3. To demonstrate the developed increased microbial oil recovery technology in field tests.

The three-year research project began in October 1999 and was subsequently granted a one-year, no-cost extension in order to accommodate the term of actual light oil recovery field tests.

Physical models were used to test the concept of controlled microbial ecology for an improved residual oil recovery system. Many long-term sand pack floods were utilized in this project. The research effort was concentrated on oil recovery in sandpack floods, followed by subsequent and complementary results from the oil recovery field trials.

The report has been formatted into four main sections of which the first section provides a description of experimental laboratory procedures, techniques, and methodologies followed by the section reporting the individual laboratory experimental results. These laboratory studies and results provided the data which guided and were necessary to initiate and conduct the field tests of the developed technology. It must be recognized that during the course of the research and field projects as results from either study became available such findings would be incorporated into both the overall laboratory or field project, which allowed the program to be centered and directed to achieve the goal of demonstrably increasing oil recovery. However, in some cases such as in the long sandpack column flooding experiments, the extended duration of such tests caused and allowed changes in the flooding protocols to be adjusted to take advantage of the new findings from laboratory or field tests. Thus, as the individual results were determined, or as different oil reservoir waters were obtained, tested, or considered for field trials, the laboratory tests were modified to take advantage of such opportunities. In addition, as limitations to the process were identified, the test program would be adjusted to circumvent, or new approaches would be directed, to overcome the observed problems. Admittedly this could cause possible abrupt changes in the beginning or an end to individual test series but it also allowed new findings to be rapidly incorporated into the test program. As a consequence the individual tests must be viewed in the context of their interaction and their interrelationship leading to the development and testing of a field ready technology.

Background

Oil reservoirs contain diverse microbial populations, including species introduced during drilling and production activities, and species native to the reservoir environment.^{14,15} Although the origin of the oilfield microflora may remain unknown and subject to speculation, it is known that an extensive and diverse microbial population can be found in most oil reserves and, except in cases of extreme biological constraint (i.e., temperature, salt, etc), indigenous microbial communities are established that adapt to the prevailing reservoir conditions. Some microbial species within these complex microbial communities exhibit the metabolic capabilities to produce known oil recovery agents such as gas, surfactants, solvents, and polymers.

Furthermore, the indigenous communities are in dynamic equilibrium with their environment and one another, but the microflora can be restructured and manipulated in a directed way to favor production of beneficial products. The calculated addition of inorganic nutrients that serve as alternate electron acceptors stimulate distinct groups of bacteria and alter reservoir ecology.¹⁶ As a consequence, the in situ metabolic activity of these select bacteria results in several bioproducts that effectively release trapped residual oil.

This research program focused on developing an understanding of a methodology to use low-cost inorganic nutrient amendments that stimulate selected indigenous microflora to utilize natural reservoir constituents to produce beneficial products. In order to assess effects that the distinct physiological groups have on oil mobilization, it was necessary to develop procedures to measure the multiplicity of effects with emphasis on increased oil recovery as the major determining measurement. Experimental work on the project included the selection of suitable microbial strains and development of test procedures for subsequent studies which demonstrated increased oil recovery.

Previous investigations of oilfield waters have endowed us with an extensive culture collection of oilfield microflora. Numerous cultures have been isolated from a wide range of field waters and facilities, including primary production wells and waterflooded fields, ranging from fresh waters to highly saline formation waters, and at various reservoir temperatures.

The cultures have been isolated on varied media, and in particular the standard API acetate-lactate SRB (sulfate reducing bacteria) medium used widely by the oil industry. The culture collection has been supplemented with isolates from several other environmental sources including activated sewage sludge, polluted marine waters and sediments, naturally attenuated remediation sites, and historically contaminated production sites. Selected cultures from the collection were used as a primary source of inocula for enrichments which were later amended with cultures grown by enrichment from the targeted field for field tests.¹⁷

The role of volatile fatty acids (VFA) as a key component^{18,19} that leads to the biogenic formation of sulfide in reservoirs was pioneered at GMT. These investigations led to the discovery of a novel technology that uses the naturally occurring VFA in a beneficial role to prevent and remove sulfide in the reservoir.^{20,21} This patented technology¹² causes the replacement of the detrimental sulfate reducing bacteria (SRB) with a beneficial microbial

population by the addition of a proprietary mixture of inorganic salts (Maxwell treatment) that act as an alternate electron acceptor.

The technology—termed “BioCompetitive Exclusion” (BCX)—is based on the presence of VFA in the reservoir and its preferential use and removal by targeted indigenous anaerobic denitrifying bacteria (DNB) when stimulated by the inorganic salt formulae.²¹ As such, there is no requirement for the addition of so-called “laboratory” microorganisms since all reservoirs contain an indigenous DNB population. Several variations of this basic successful BCX technology for the prevention and removal of biogenic sulfide are now being reported in laboratory and field studies²²⁻²⁵ and show that SRB can be suppressed by the introduction of alternate electron acceptor salts. However, reports of these alternate sulfide suppression systems remain silent as to the synergistic benefits which result from the Maxwell treatment. In the Maxwell system the proliferation of the DNB population has the added potential of increasing oil recovery by the production of their metabolic products, including gases (N₂ and CO₂), biosurfactants, biosolvents, and biopolymers.

This past work of experiments, field data, and results has identified the critical role of VFA in oil field brines and shown its impact on reservoir souring and corrosion, as well as the potential for increased oil recovery. Such research provides strong background information on VFA in reservoir fluids, and was coupled with the ongoing studies of VFA and the added stimulation induced by the alternate electron acceptor nitrate salt to enhance microbial interaction in oil reservoirs to offer a unique information base contributing to the successful completion of the program.

Experimental Methodologies and Protocols

Culture Studies

Initial cultural studies centered on the isolation and development of predominantly polymer producing cultures with the potential to function as mobility control agents.²⁶ As the program proceeded the cultural techniques were expanded to develop and enrich for organisms that had demonstrable oil recovery capabilities by multiple product formation as determined by sandpack and field results.

Bottle Tests

The initial objective of the culture studies was to select high polymer producing cultures from natural microbial consortia and to determine and develop conditions which encourage maximum polymer production. Produced water samples were collected from production fields in Washington County Oklahoma, Coleman County Texas, Ector County Texas, and Natrona County Wyoming.

Water samples were added directly to liquid selective culture media and incubated anaerobically at 40°C. Selective media enriched environmental samples for denitrifying bacteria (DNB) and general anaerobic bacteria (GAB). Enrichment media formulations are listed in Tables 1 and 2.

Table 1. Composition of denitrifying bacterial (DNB) medium.

	g/liter
Na ₂ HPO ₄ •7H ₂ O	1.5
KH ₂ PO ₄	1.5
NH ₄ Cl	0.3
MgSO ₄ •7H ₂ O	0.1
Trace minerals	2.0
Na Acetate	1.64
NaNO ₃	1.7
NaCl	7.5
YE	0.5

Table 2. Composition of general anaerobic bacterial (GAB) medium.

	g/liter
Sea Salts	22.0
MgSO ₄ •7H ₂ O	0.1
Na ₂ HPO ₄ •7H ₂ O	0.45
KNO ₃	0.6
Yeast Extract	3.0
HEPES	0.5
EDTA Disodium Salt	0.75
Glucose	10.0
Cysteine HCl	0.5
Agar	17.5

Mixed cultures enriched in the liquid medium were transferred to solid medium and incubated at 40°C in an oxygen-free atmosphere containing 5% CO₂, 10% H₂, and 85% N₂. Isolates were picked by colony appearance from streak plates of the enrichment cultures. Cultures were maintained on solid media at 25°C in an anaerobic environment. Isolates were partially characterized using general physiological and cell morphological characteristics.

Representatives from the stock culture collection and recent isolates were enriched and used as composite inocula for growth studies. The primary base medium, Medium A, was a derivative of seawater salts amended with microbial nutrients (Table 3). The use of Medium A allowed for the rapid preliminary screening of numerous cultures and isolates. All growth studies were run at room temperature (~23°C), 40°C, and 55°C, under anaerobic conditions in 10-ml serum vials sealed with butyl rubber septa. Control tests were run with select cultures under aerobic conditions.

Table 3. Compositions of primary screening and growth media.

Nutrient	Amount (per liter)	
	Medium A	Medium G
Instant Sea Salts	35 g	35 g
Sodium acetate	1000 mg	2000 mg
Sodium nitrate	100 mg	200 mg
Sodium phosphate (dibasic anhydrous)	25 mg	25 mg

As the screening program progressed, Medium A was modified and supplemented to establish and isolate the most active cultures. Media B through G were composed of Medium A fortified with rich supplements including ammonium nitrate, yeast extract, glucose, or defined media including NIH thioglycollate, DNB medium, or API acetate-lactate SRB medium. However, because of the requirement for media composition consistent with nutrient levels in reservoir

brines, and which would be realistic for field brines, the addition of rich nutrient supplements was restricted and a reformulated sea salts base medium, Medium G, was established (Table 3).

Sandpack Development Studies

At the same time that the media compositions were modified, the sandpack column systems were developed, employed, and refined to demonstrate the growth, activity, and potential of the candidate cultures.^{27,28} Numerous variations of the slim tubes, batch reactors, and sandpacks were tested for versatility, applicability, and ease of assembly and operation while maintaining conditions which represented field environments. Fluid-filled sandpack columns were employed and led to the development of a modified microcosm scale sand-packed column which had the attributes of both a sand pack while maintaining the advantages of a small-scale bottle test procedure.

The early decision to use sandpack columns in place of oilfield or Berea cores was considered as desirable to be able to run the large variety of nutrient formulations, cultures, oil conditions, etc., that would be anticipated in building a base of information to develop a practical system for widespread field usage. The ease and rapid construction of the various configurations of the sandpacks, including being able to scale such packs to large sizes, in this case to 10 ft lengths, had great advantages for running many series of duplicate, parallel, or sequential tests at various temperatures, flooding rates, different waters or oils, etc. Such versatility and advantages would not have been possible with cores. At any rate, these sandpack tests which were designed as a guide and a pathfinding system for future core studies and were found to be a very successful system for developing field treatment. However, the sandpacks do not duplicate some characteristics of cores such as tight sands, low permeability, heterogeneity, etc., but do measure microbial growth through a homogeneous sand. Surprisingly, the general reproducibility of sandpack characteristics such as permeability, etc. was better than had been expected and results in a series of tests could be compared. Furthermore, their use for multiple tests of anaerobic growth in a reservoir environment shows them to be extremely responsive and changes in the reservoir ecology can be easily demonstrated and related to oil recovery. Therefore, in spite of the limitations of the sandpack methodology the systems are unsurpassed in their versatility, data generation, and ease of operation for the proposed test program.

Microcosm Scale Sandpack Column

The initial preferred system which met the criterion and offered practical and controlled test conditions centered on the use of a sand-packed slim tube constructed from 6 mm ID glass tubing (Figure 1). A 7.5 cm section of the tube was packed with washed Mill Creek sand confined with glass wool plugs to yield a sand-packed column with a bulk volume of 2 cm³ and a void mixing volume of approximately 2.66 cm³ on each end. The sand-packed slim tubes were saturated with growth medium, sealed on each end with butyl rubber septa to maintain anaerobic conditions, and mounted vertically. Inocula and treatments were injected into this system by a syringe through the lower septum.

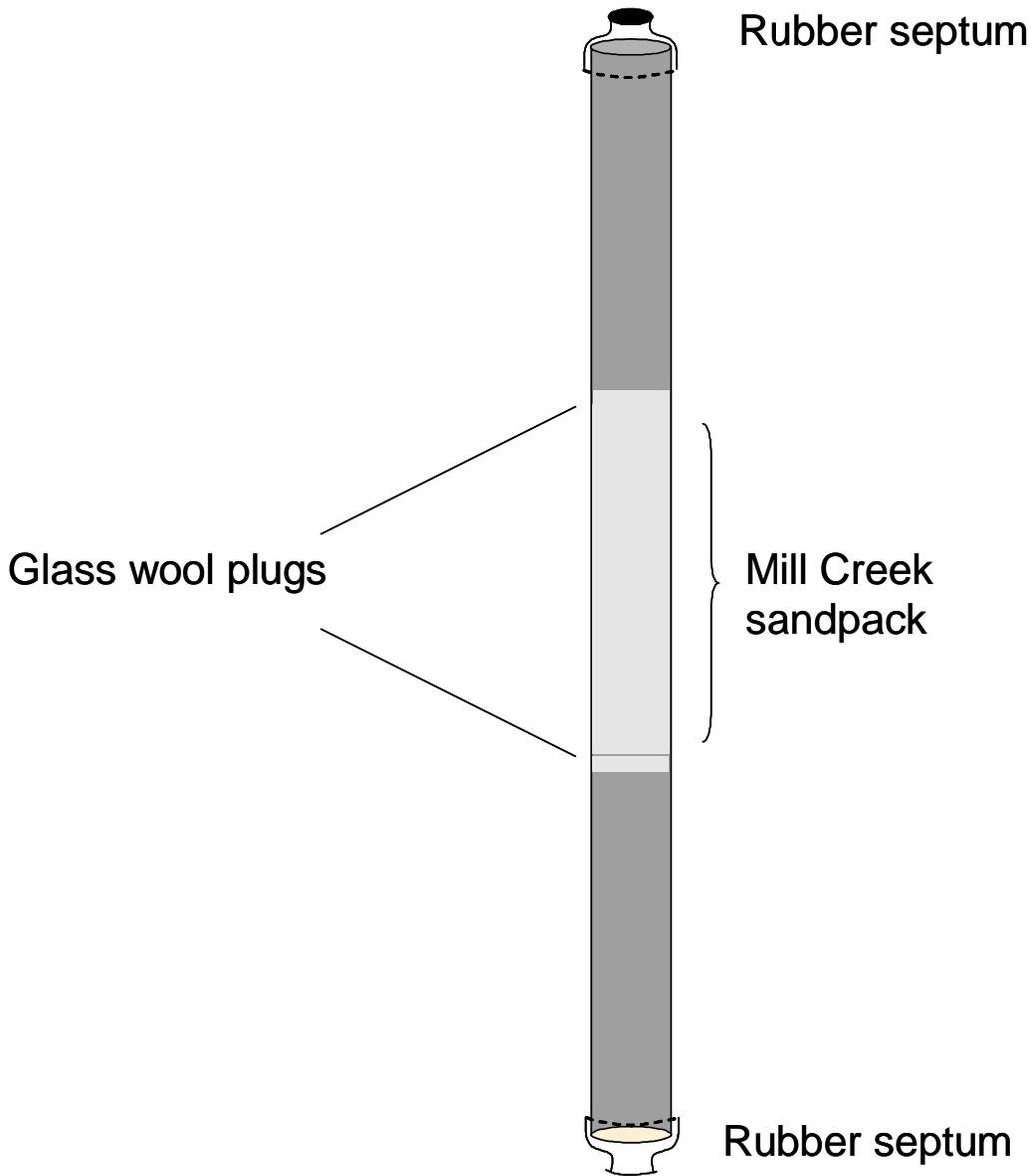


Figure 1. Sand-packed slim tube (6 mm ID).

This test system offered the advantages of visual observations of both the bottom (influent) and top (effluent) separated by the porous medium. The presence of the sand-packed zone reduced exchange of cells throughout the column and required that cells penetrate the sand while nutrients were readily exchanged. The columns were maintained anaerobically and incubated at room temperature, 40°C, and 55°C. Samples were withdrawn periodically from influent and effluent mixing zones by syringe and new medium was added as required. The sand-packed slim tube system fulfilled all the requirements for rapidly and effectively identifying and growing cultures which showed potential of being candidates for further testing.

Four strains were selected for further study. Initial characterization of these strains is shown in Table 4.

Table 4. Strains selected for experiments.

Isolate	Gram Reaction	Description
Circle 1	ND	ND
AA	+	Mixed culture, rods
41A	ND	ND
33	+	very short large rods

ND = not determined

The strains were grown on DNB (denitrifying bacteria) media (Table 1) for viscosity measurements on a Brookfield viscometer. Cells were harvested and suspended in a 25% glycerol solution for cryostorage.

Nutrient Studies

Experiments were run using various nitrogen formulae and sources. The strains were grown in anaerobic Hungate tubes containing the media listed in Table 5, plus various nitrogen sources, at pH 7.2. The cultures were incubated 7 days at 40°C.

Table 5. Media for nitrogen source experiment.

Component	Amount per liter
Na ₂ HPO ₄ •7H ₂ O	1.5 g
K ₂ HPO ₄	1.5 g
MgSO ₄ •7H ₂ O	0.1 g
Hutner's trace minerals	20 ml
Na Acetate	1.64 g
NaCl	7.5 g
Yeast extract	0.5 g

Experiments were run using various carbon sources. The strains were grown in anaerobic Hungate tubes containing the media listed in Table 6, plus various carbon sources, at pH 7.2. The

carbon sources were added at concentrations of 0.1%, 1%, and 10%. The cultures were incubated 8 days at 40°C.

Table 6. Media for carbon source experiment.

Component	Amount per liter
Na ₂ HPO ₄ •7H ₂ O	1.5 g
K ₂ HPO ₄	1.5 g
NH ₄ Cl	1.3 g
MgSO ₄ •7H ₂ O	0.1 g
Hutner's trace minerals	20 ml
NaNO ₃	1.7 g
Yeast extract	0.5 g
NaCl	7.5 g

The objective of the continuing culture studies was to select cultures from natural microbial consortia that will utilize natural reservoir constituents to produce beneficial products for oil mobilization. Strains isolated from produced water samples were tested with various nutrient combinations. The nutrient amounts are shown in Table 7. It should be noted that no expensive complex nutrient supplements such as yeast extract were added in future media compositions or flooding systems.

Table 7. Nutrient components.

Component	g/L	ppm
Sodium acetate	1.64	1180 acetate
NaNO ₃	1.70	1240 nitrate
Na ₂ HPO ₄	0.75	1050 phosphate
KH ₂ PO ₄	1.50	1050 phosphate
MgCl ₂ •6H ₂ O	0.10	12 magnesium
NaNO ₂	1.70	1140 nitrite

Eight different nutrient combinations were used, and named Nutrient 1 through Nutrient 8, as shown in Table 8.

Table 8. Nutrient compositions.

Component	1	2	3	4	5	6	7	8
Sodium acetate	X	X	X	X	X	X	X	X
NaNO ₃	X	X	X	X	X	X	X	X
Na ₂ HPO ₄	X	X	X		X			X
KH ₂ PO ₄	X	X		X		X		X
MgCl ₂ •6H ₂ O	X		X	X			X	X
NaNO ₂								X

Examination of Field Waters and Flooding Culture Consortium Development

Brines and oils were obtained from several oil field sites in Oklahoma. The leases were designated as Hominy, Shidler, and the Naval Reserve. The brines were analyzed for sulfate, TDS (total dissolved solids), iron, and acetate. The brines were also checked for microbial activity, and to determine whether microbes from our collection would grow in them. Results of analysis of oil field brines are shown in Table 9.

Table 9. Analysis of oil field brines.

Brine sample	Sulfate (ppm)	Iron (ppm)	TDS (%)	Acetate (ppm)
Hominy	0	12	18.2	7
Naval Reserve	0	11	18.0	10
Shidler	0	10	8.0	3

As Table 9 shows, all three Oklahoma brines had a much higher salt content than the enrichment media used. Anaerobic bacteria were present in the Shidler brine, but were not identified in the other two brines. However, growth was observed in the Hominy brine, when amended with acetate and nitrate. Based on these results, it was determined that reservoirs with a lower salt concentration, such as 3.5% NaCl, would be the focus of the investigations.

Samples were obtained from a wastewater treatment plant to attempt to isolate denitrifying bacteria and other bacteria which may be suitable for this project.

In addition, brines from California oilfields suggested for field testing of the developed oil recovery systems were analyzed (Table 10).

Table 10. Brine analysis of California Field Waters.

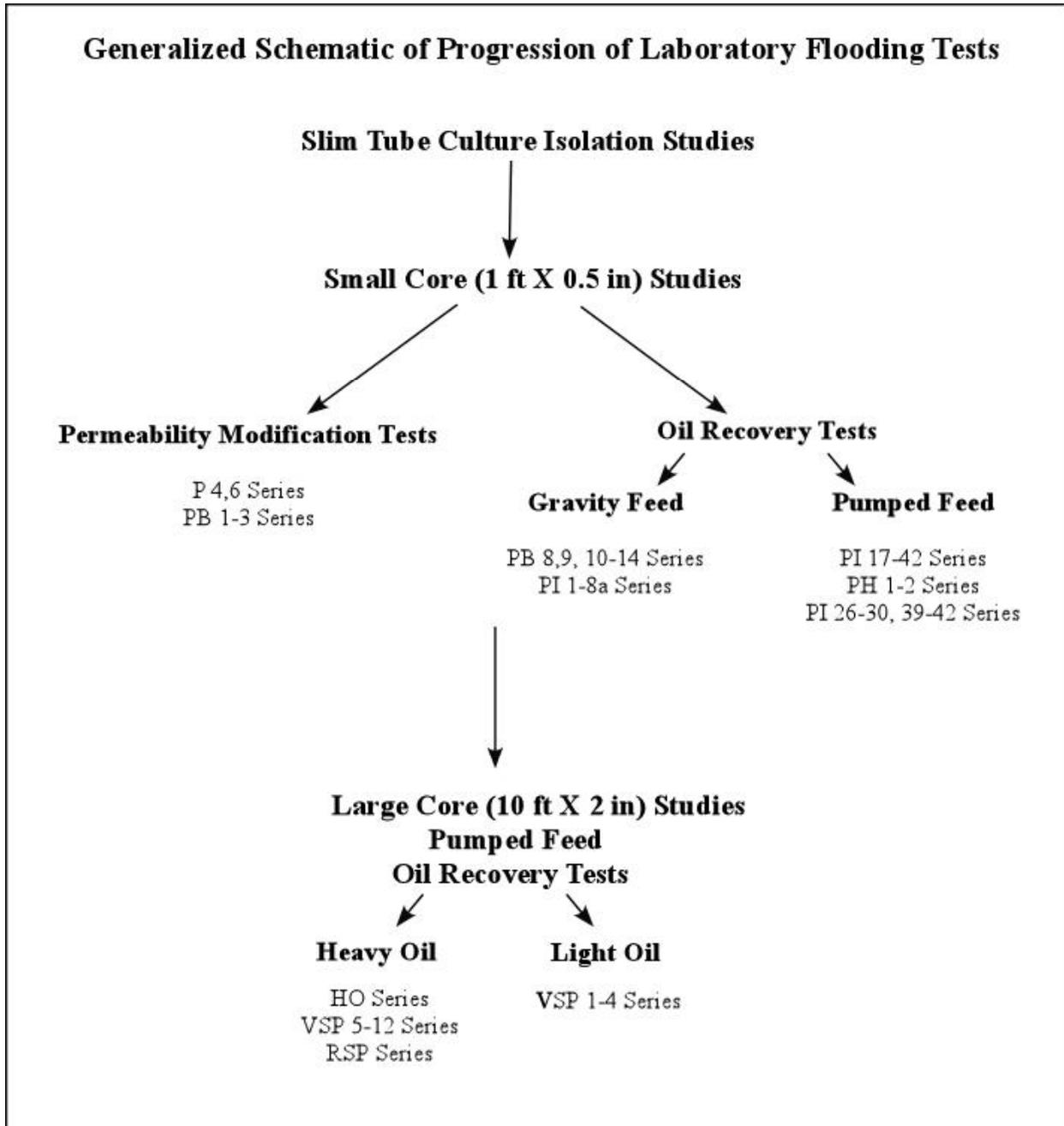
Brine	pH	Total Dissolved Solids (%)	Iron (ppm)	Sulfate (ppm)	Microbial Counts (log cells/ml)			VFA (ppm)
					SRB	DNB	GAB	
Tulare produced	6.5	1.2	5	234	2	0	3	14
Tulare aquifer	7.1	1.7	2	33	4	5	3	0.5
Diatomite	7.0	3.0	9	0	4	1	3	29
Ventura	7.1	1.9	7	3	2	3	2	734

Nutrient T

A new proprietary nutrient composition, referred to as Nutrient T, was developed which was composed of a formulation of complex carbon-based supplements. This supplement was obtained in an untreated liquid form and was used directly in this liquid state. In the liquid form the product proved difficult to store and was subject to microbial deterioration. To solve this problem, the liquid product was air-dried to preserve the product and prevent loss of the active nutrient components. The dry form was reconstituted to same solids concentration as in the liquid form prior to testing. Bottle tests were conducted to test the system at different temperatures and with different oilfield brines from California. Water analysis for the brines is shown in Table 9. The system was also tested to compare a liquid version of the nutrient with a dry version. The tests were done in 50 ml anaerobic serum bottles containing 20 ml nutrient mixed with brine. The tests were run at 35° C and 55° C. The bottles were checked periodically for gas production, which is a major product of this new biosystem.

Sandpack Floods

Multiple series of sandpack tests were conducted to demonstrate the effects of changing the composition and quantity of various nutrient additions. A generalized schematic of this progressive series of flooding tests is outlined in the following diagram:



Cultures used as inocula for core tests PI, PB, and PH were composite consortia from the culture collection and from bottle and slim tube studies. Culture inocula for large core studies were obtained from enrichments of the microflora of the target (Tulare, Ventura, Diatamite) fields.

These series of tests were run for various periods of time, at various conditions, and the observed changes in permeability, culture response, and rates and quantity of oil recovered were measured. The test series of sandpacks were identified as PI, PB, and PH. The composition of flood waters in the PI series of tests was based on an Instant Ocean formulation. The composition of all the flood waters in the PB series of tests was based on the Velma rural water (Table 13) and was a synthetic field brine. The composition of the flood waters in the PH series of tests used field brine from the Hominy field in Oklahoma.

Table 11. Base Brines for Sand Pack Studies

Test Series	Base Brine Formulation
<i>Small cores</i>	
PI	Instant Ocean Brine (3.5% NaCl)
PB	Velma Synthetic Brine (2% NaCl)
PH	Hominy Field Brine
P	Synthetic brine (0.75% NaCl)
<i>Large cores</i>	
HO	Tulare Field Brine
VSP 1-2	Ventura Field Brine→Instant Ocean (2% salt)*
VSP 3-4	Diatamite Field Brine→Instant Ocean (3% salt)*
VSP 5-12	Tulare Field Brine→Instant Ocean (1.5% salt)*
RSP	Tulare Synthetic Brine→Instant Ocean (1.5% salt)*

* The Instant Ocean formulations were matched to the VFA content identified in brine analysis (Table 10).

Flooding Tests

The cultures which were identified in the preliminary screening program were further developed by altering medium composition to stimulate growth and polymer production. Additional screening tests were conducted to continue identifying new cultures that merited further development. The sandpack flooding tests were designed to utilize various sized sand-filled

columns which were incubated horizontally or vertically. The flooding media was injected into the core by gravity feed or by pump from a reservoir. A schematic of the system is shown in Figure 2. The feed could be added daily or at longer intervals and could be amended as needed for testing individual components. The system was not sterilized to conform to expected field practices but contamination was minimal due to the restrictive nutrient composition, anaerobic conditions, salt content, and temperatures of incubation. In addition, the use of the preconditioned microbial consortium used as inoculum favored the development of the selected microflora.

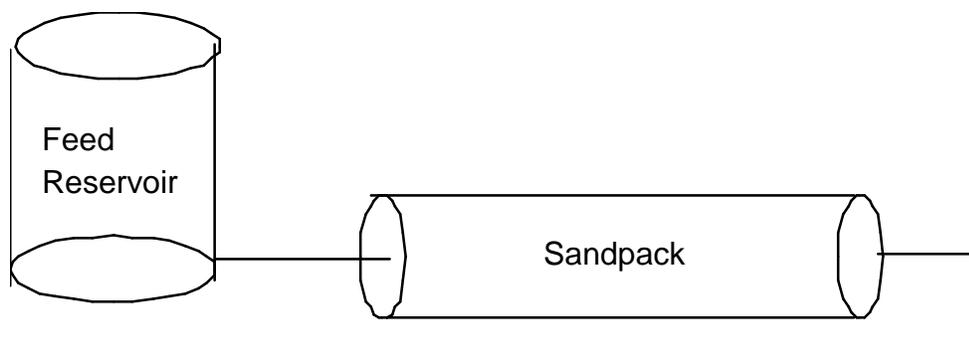


Figure 2. Sandpack flooding schematic.

Polymer Flooding Studies

Sandpack flooding experiments to demonstrate production of polymer in-situ were conducted using synthetic brine based on Velma rural water. Brine composition is shown in Table 13. Several floods were run to develop the procedure and apparatus. After the technique was developed, a successful flood was completed. Sandpack, PB-2, was 25.3 cm in length and 1.27 cm in diameter. It was packed with Mill Creek sand. The initial permeability was 10.4 darcies. The sandpack was inoculated with 1 PV of culture 33 grown in DNB broth, then flooded with additional DNB broth with no nitrogen source at 40° C (composition found in Table 1, except that no NaNO₃ was added).

Sandpack, PB-3 was 25.8 cm in length and 1.27 cm in diameter and was packed with Mill Creek sand. The initial permeability was 12.6 Darcies. The sandpack was inoculated with 1 PV of culture 33 grown in DNB broth, then flooded with additional DNB broth at 40° C (see composition in Table 1).

Another flooding experiment was done with the addition of sucrose. Sandpack PB-1 was 26.8 cm in length and 1.27 cm in diameter, also packed with Mill Creek sand. The initial permeability was 11.1 darcies. It was inoculated with 1 PV of culture 33 grown in DNB broth, then flooded with additional DNB broth (See Table 1) containing 10% sucrose to determine if sucrose would stimulate polymer production more than the addition of nitrate alone. This flood was also tested at 40° C.

Sandpack flooding experiments to demonstrate production of polymer in-situ were conducted using synthetic brine (0.75% NaCl). These experiments were conducted at ambient temperature. The sand pack columns were made of glass, and were 1.27 cm in diameter. Mill Creek sand was used to pack the columns. After brine saturation, the packs were inoculated using gravity feed with four PV inoculum. Pack P-4 was inoculated with culture A1 grown in DNB broth. Pack P-6 was inoculated with culture 1 grown in DNB broth. These cultures were isolated from oilfield brines. The packs were then flooded with fresh DNB media, shut in, and incubated at ambient temperature. Pack P-4 was incubated for 10 days. Pack P-6 was incubated for 13 days. After incubation, the post-treatment permeability was measured.

Sand pack floods were conducted to measure flow rate reduction due to biopolymer production. The experiment was conducted at room temperature. Sand packs PI-29 and PI-32 were saturated with Instant Ocean synthetic seawater brine. PI-29 was inoculated with a bacterial solution and an acetate/nitrate nutrient broth. Both packs were shut in for nine days. Flooding was then started with Instant Ocean amended with nitrate and acetate. Flow rates were measured periodically. Sand pack flooding experiments were conducted to determine the effects of various nutrients and flooding regimes. The sand pack columns were made of glass, and were in lengths ranging from 24 to 28 cm, and were 1.27 cm in diameter. Mill Creek sand was used for the sand packs.

Small Sandpack Oil Recovery Tests

PI-1 through PI-8a Corefloods

Many sand pack flooding experiments were conducted to determine the effects of various nutrients and flooding regimes on oil recovery. All experiments were conducted at 40° C unless otherwise noted. The sand pack columns were made of glass, and were 1.27 cm in diameter. Mill Creek sand was used for the sand packs. The packs were saturated with Instant Ocean synthetic brine (PI).

After brine saturation, the packs were inoculated using gravity feed with one (PV) of a mixed culture grown in DNB broth. The packs were then flooded with thioglycollate-reduced synthetic brine with 1.64 g/l sodium acetate (1180 ppm acetate) added (RAB) to wash out the broth. The packs were incubated for three days. The packs were then saturated with Skiatook-11 crude oil. PI-8a was inoculated after oil saturation. Details for each pack are reported in Table 12.

Table 12. Sand packs PI-1 through PI-8a. (Instant Ocean Brine)

Sand pack #	Length (cm)	PV (ml)	OOIP (ml)
PI-1	25.5	13.1	9.0
PI-3	26.5	12.4	10.3
PI-4	25.5	12.4	13.0
PI-5	25.5	13.2	10.6
PI-7	25.4	12.9	11.2
PI-8	25.4	13.4	10.9
PI-8a	25.6	13.9	12.0

The packs were flooded with reduced acetate brine (RAB) to residual oil saturation. Nutrient treatments were then started by adding sodium nitrate and/or sodium acetate to the brine. The packs were flooded continuously over a period of several days and were not shut in.

PB-8 through PB-14 Corefloods

Additional sand pack flooding experiments were conducted to determine the effects of various nutrients and flooding regimes on oil recovery. All experiments were conducted at 40° C unless otherwise noted. The sand pack columns were made of glass, and were 1.27 cm in diameter. Mill Creek sand was used for the sand packs. The packs were saturated with synthetic brine based on the composition of Velma rural water, which was used for a previous field test. Brine composition is shown in Table 13.

Table 13. Composition of Velma synthetic brine.

Component	g/L
NaCl	20.000
CaCl ₂ •2H ₂ O	0.35
MgCl ₂ •6H ₂ O	0.25
Na ₂ SO ₄	0.20
NaHCO ₃	0.075

After brine saturation, the packs were inoculated using gravity feed with one pore volume of a microbial culture named A1 grown in DNB broth. The packs were then flooded with reduced synthetic brine with 1.64 g/l sodium acetate (1180 ppm acetate) added (RAB) to wash out the broth. The packs were re-inoculated to ensure good transport of the bacteria, then flooded again with RAB. The packs were saturated with Skiatook-11 crude oil. Details for each pack are reported in Table 14.

Table 14. Sand packs PB-8 and PB-9.

Sand pack #	Length (cm)	PV (ml)	K (D)	OOIP (ml)
PB-8	24.7	11.1	9.1	10.6
PB-9	16.8	12.7	9.9	9.8

The packs were flooded with RAB to residual oil saturation. Nitrate treatment was then started by adding sodium nitrate (1240 ppm nitrate) to the RAB. This treatment is referred to as RANB. The packs were flooded over a period of several days, and were shut in each night. Sand packs PB-10 through PB-14 were prepared using the same procedure as PB-8 and 9, except the packs were inoculated with bacteria only once. Details for each pack are shown in Table 15.

Table 15. Sand packs PB-10 through PB-14.

Sand pack #	Length (cm)	PV (ml)	K (D)	OOIP (ml)
PB-10	26.4	12.2	9.8	9.6
PB-11	25.0	12.9	10.6	9.6
PB-12	24.5	12.7	9.9	10.5
PB-13	25.6	12.3	11.0	9.6
PB-14	25.7	12.7	11.5	9.6

The packs were flooded with RAB to residual oil saturation. Nutrient treatments were then started by adding sodium nitrate alone or sodium nitrate and sodium phosphate to the brine. The packs were flooded continuously over a period of several days and were not shut in.

PI-17 through PI-24 Corefloods

Sand packs PI-17 through PI-24 were prepared using the same procedure as PB-10 through 14 except that Instant Ocean synthetic brine was used. The inoculum was suspended in brine and injected rather than being injected with DNB broth. A roller pump was used instead of gravity feed to maintain a more constant flow rate. Details for each pack are shown in Table 16.

Table 16. Sand packs PI-17 through PI-24.

Sand pack #	Length (cm)	PV (ml)	OOIP (ml)
PI-17	25.2	14.0	10.0
PI-18	26.4	13.9	10.6
PI-19	24.6	13.7	10.8
PI-20	25.1	14.4	10.8
PI-21	25.4	13.8	10.6
PI-22	26.3	14.2	10.9
PI-23	25.6	13.9	10.8
PI-24	25.3	13.7	11.2

PI-26 through PI-42 Corefloods

After brine saturation with Instant Ocean synthetic brine, oil saturation with Skiatook-11 crude oil obtained from an Oklahoma oil field, and waterflooding to residual oil saturation, packs PI-26 through PI-30 and PI-39 through PI-42 were inoculated using gravity feed with one PV of a mixed microbial consortium. The packs were shut in overnight. Flooding was then begun with Instant Ocean brine amended with acetate and/or nitrate. Details for each pack are reported in Table 17.

Table 17. Sand packs PI-26 through PI-30 and PI-39 through PI-42.

Sand pack #	Length (cm)	PV (ml)	OOIP (ml)
PI-26	25.4	14.0	10.8
PI-27	24.5	14.1	11.2
PI-28	27.1	12.2	9.2
PI-29	24.5	14.4	12.0
PI-30	25.0	14.2	11.2
PI-39	26.7	12.6	10.0
PI-40	24.4	13.3	10.9
PI-41	25.7	13.6	11.0
PI-42	26.0	13.6	11.4

PH Corefloods using Field Brines

Sand packs PH-1 and PH-2 were prepared using the same procedure as PI-26 through PI-30 except that Hominy field brine and oil (obtained from an Oklahoma oil field) were used. Details for each pack are shown in Table 18. Both packs were inoculated with microbial culture A1 combined with bacteria isolated from Hominy brine. PH-1 was a control, with no nutrient added. PH-2 was treated with Max-Well Waterflood Treatment, a proprietary nutrient formula.

Table 18. Sand packs PH-1 and PH-2.

Sand pack #	Length (cm)	PV (ml)	OOIP (ml)
PH-1	24.7	15.6	11.4
PH-2	24.6	16.2	12.2

The oil recovery results in the small sandpack columns indicated that increased oil recovery occurred; but the short residence time and small volumes of oil release made it difficult to measure the increases. In addition, in some cases the production of large volumes of gases, while improving oil recovery, proved difficult in operation of the systems. For these reasons a larger sandpack system was desired and the use of 10 ft long 2 inch in diameter plastic PVC pipe sandpack columns was initiated. This large flooding system required larger pumps which could control flow rates and volumes more accurately and constantly.

Large Sandpack Flooding Tests

The initial large sandpack flood was conducted in a 10-foot long plastic tube with an inner diameter of 1.5 inches. The tube was packed with Mill Creek sand and saturated with Belridge produced water (from a California field). The pack was then saturated with Skiatook-11 crude oil, and waterflooded to residual oil saturation. The test was conducted at 37° C. After waterflooding, the pack was inoculated with a microbial consortium and treated with Max-Well

2000 Waterflood Nutrient. Maxwell 2000 nitrate-based product formulae are composed of various patented synergistic component blends. The formulae are specifically designed as a nutrient for beneficial denitrifying bacteria that produce several bioproducts that cause the release and mobilization of trapped residual oil. Additionally, Maxwell treatments are very effective in eliminating H₂S in sulfide control programs.

Heavy Oil (HO) Corefloods

As favorable results of the flooding tests with light oil were obtained, an increased interest by California operators on the use of the technology for heavy oils became an important consideration.²⁹ As a result of such interest the program was expanded to include tests with heavy California crude oils and the brine formulation was changed together with the introduction of cultures isolated from the targeted fields. The information and technology developed for the light oil process was modified and adapted for studies to develop a technology for heavy oil reservoirs.

Three sand pack flooding experiments were conducted to determine the effects of various nutrients and flooding regimes on heavy oil recovery. All experiments were conducted at 100° F (37.8° C). The sand pack columns were made of plastic, and were 2 inches (5.08 cm) in diameter and 10 feet (3 m) in length.

After saturation with Belridge field brine, oil saturation with Belridge heavy oil (viscosity 152 centipoise at 150° F) obtained from a California oil field, and waterflooding to residual oil saturation, the packs were inoculated with a microbial consortium. The packs were shut in. Treatment was then begun with customized Max-Well 2000 nutrient mixed with Belridge brine. After oil production ceased with this nutrient treatment, the sand packs were treated with the new Nutrient T biosystem. Details for each pack are reported in Table 19.

Table 19. Heavy Oil Sand packs. (HO Series)

Sand pack #	PV (ml)	OOIP (ml)
HO-101	2250	1643
HO-102	2000	1130
HO-103	2100	1930

VSP and RSP Corefloods

Repetitive sand pack flooding experiments were conducted to determine the effects of various nutrients and flooding regimes on oil recovery. All experiments were conducted in the temperature range of 38 to 50 degrees Centigrade. Sand pack columns were made of PVC plastic, and were 2 inches (5.08 cm) in diameter by 10 feet (3 m) in length.

Sand packs VSP-1 and VSP-2 were saturated with field brine and Ventura light oil. VSP-3 and 4 were saturated with Diatomite brine and oil, while VSP-5 through 12 were saturated with Tulare

brine and Tulare “heavy” 13 API gravity oil., all obtained from a well-known California oil field. After water flooding to residual oil saturation, the packs were inoculated with a microbial consortium that had been isolated from the field brine, then shut in for an incubation period. Water flooding was then resumed with various types of nutrients as amendments. The nutrients included the proprietary formulation nutrient T and a second-generation proprietary formulation, nutrient MORG.

The RSP cores were prepared with fine unwashed sand, packed into 2” diameter, 10 ft. long PVC plastic coreholders, placed in a vertical orientation. The cores were then saturated with 1.5% Instant Ocean artificial brine inoculated with Tulare reservoir bacterial cultures from DNB, GAB, and SRB media. The cores were then partially saturated with heavy oil from the Tulare reservoir in order to approximate a waterflooded reservoir with approximately 33% of OOIP, based on earlier waterflood results. The cores were oriented for bottom to top flow and incubated at 45°C, and nutrient treatment was begun.

Core RSP-C was flooded continuously with Nutrient T. Core RSP-E was flooded continuously with Nutrient T and 100ppm Maxwell formulation (MW). Core RSP-F was flooded with the same Nutrient T + 100ppm MW, but on a once a week injection schedule, with 6 days of shut-in between injections, until one PV of treatment was reached. At this time, flooding was changed to the continuous schedule. After 138 days of treatment, flooding for all cores was switched to eight hours on, 16 hours off to increase residence time. After 167 days of treatment, because the oil recovery had reached a plateau, the nutrient concentration for RSP- E and F was changed to Nutrient T + 1000ppm Maxwell.

Table 20. Nutrient Amendments and Flooding Protocols for VSP and RSP Series Sandpacks.

Core Number	Nutrient	Oil Type	Orientation of flow	Flooding Protocol
VSP-1	MW	Light	Horizontal	Continuous
VSP-2	MORG+MW	Light	Horizontal	Continuous
VSP-3	MW	Light	Horizontal	Continuous
VSP-4	MORG+MW	Light	Horizontal	Continuous
VSP-5	Nutrient T	Heavy	Horizontal	Continuous
VSP-6	Nutrient T	Heavy	Horizontal	Continuous
VSP-8	MORG	Heavy	Horizontal	Continuous
VSP-9	MW	Heavy	Horizontal	Continuous
VSP-10	MORG	Heavy	Horizontal	Continuous
VSP-11	Nutrient T	Heavy	Vertical	Continuous
VSP-12	MW	Heavy	Vertical	Continuous
RSP-A	MW	Heavy	Vertical	Continuous
RSP-B	MW	Heavy	Vertical	Intermittent
RSP-C	Nutrient T	Heavy	Vertical	Continuous
RSP-E	Nutrient T+MW	Heavy	Vertical	Continuous
RSP-F	Nutrient T+MW	Heavy	Vertical	Intermittent
RSP-G	MORG	Heavy	Vertical	Continuous
RSP-H	MORG	Heavy	Vertical	Intermittent

Laboratory Results and Discussion

Bottle Tests

This research program was initiated after a review of the currently available literature, and previous studies of the microflora and biochemical constituents of oil field waters. The review identified areas that could be targeted to offer the greatest potential for developing and improved oil recovery system and technology. Techniques for the identification of the capabilities of isolated cultures were developed and tested in the preliminary screening program. The modified sand-packed slim tube system proved to be a versatile and easily handled apparatus for employing screening methodologies.

Enrichment cultures from all production fields sampled in this period yielded consortia which grew anaerobically at 40°C. Undefined consortia from liquid cultures were streak plated on solid culture media and probable polymer-producing strains were selected by colony appearance. Promising polymer-producing strains produced copious volumes of biomass when grown on solid medium and had slimy or mucoid colony appearance.

The most promising polymer-producing strains from each location are listed in Table 21. Utilization of alternate carbon sources for growth was examined in isolates by cross testing for growth on both DNB medium and GAB medium. Isolates from three of the locations were able to utilize both acetate (DNB medium) and glucose (GAB medium) as growth supporting carbon sources. The isolates also grew aerobically at 40°C and 55°C when tested. The polymer-producing strain isolated from the Ginnings Lease did not exhibit growth on GAB medium or aerobically on GAB or DNB medium in these tests.

Table 21. Polymer-producing isolates enriched from produced water samples.

Source	Growth					
	DNB	GAB	Anaerobic	Aerobic	40°C	55°C
Marco Lease, Washington County, Oklahoma	+	+	+	+	+	+
Ginnings Lease, Coleman County, Texas	+	-	+	-	+	/
NPU Lease, Ector County, Texas	+	+	+	+	+	+
NPR-3 (Teapot Dome), Natrona County, Wyoming	+	+	+	+	+	+

+ Growth confirmed

- Growth not confirmed

/ Not tested

The initial test period successfully established a collection of cultures which are able to grow and show activity at conditions which are representative of many reservoir waters. Growth conditions employed consisted of supplying a minimal carbon source (acetate) combined with the use of nitrate as an electron acceptor in a seawater base medium. This restricted growth medium limited the number of cultures able to survive and grow (Table 22). Results show that several cultures produced good growth and polymer production (i.e., flocculant appearance) within a period as short as 48 hours. The identified inocula included cultures able to grow anaerobically at room temperature, 40°C, and 55°C. Results also identified the presence of sulfate reducing bacteria (SRB) which are indicative of the anaerobic conditions that exists within the conditioned columns. Grey to black coloration of the white sand indicated the presence of sulfide generation. In several cases the top of the slim tube developed more growth than the bottom, suggesting that a sulfide-utilizing population was being encouraged when rich media in the absence of nitrate were employed. This was expected with several cultures which had been isolated from sulfide-containing waters and had been maintained in this condition.

The cultural and growth tests demonstrated that a varied and extensive population of all types of indigenous microorganisms was present in oilfield environments. While specific predominant species could be selected by nutrient modification and the number of types could be increased by the use of a rich media composition, the use of a “lean” medium still provided a very diverse population which was representative of populations in an oil reservoir. Since these results confirmed that most reservoirs contain diverse and prolific natural microflora and such organisms could be developed on minimal media the objective of using natural microbial consortium populations was considered very feasible and practical for oil recovery studies. However to demonstrate these specific points of culture selection by nutrient modification an example is presented of polymer production enhancement. This stage of investigation was complemented by directed development of a mixed anaerobic microbial consortium which had oil releasing capabilities but would proliferate with minimum nutrient requirements.

Table 22. Growth and appearance of selected mixed and composited cultures in sand pack columns.

Culture #	Medium	Inocula	Room Temp			40 ° C			55 ° C		
			Top	Sand	Bottom	Top	Sand	Bottom	Top	Sand	Bottom
1	B	Mixed	+	-	+/-	+/-	grey	+/-	+/-	-	+/-
2	C	Mixed	+	-	+/-	+/-	grey	+/-	+/-	-	+/-
3	C	20 cultures	+	grey	+	+/-	black	+	+/-	black	+/-
4	C	Mixed	+/-	grey	+	+	black	+	+/-	black	+
5	F	Composite	+	grey	+/-	++	black	+	+/-	grey	+
6	G	Composite	+	grey	+/-	++	black	+	+/-	grey	++
7	H	Composite	+	grey	+/-	++	black	+	+/-	grey	+
8	G	Composite	+	grey	+/-	+/-	-	+ floc	+/-	-	++ floc
9	G	T1	+	-	+	+/-	-	+	+/-	-	+ floc
10	G	T2	+	-	++	+	-	+ floc	+/-	-	+
11	G	D1	+/-	-	+/-	+	grey	++	+/-	-	+/-
12	G	D2	+/-	grey	+	+	grey	++	+/-	-	+/-
13	G	D3	+/-	-	+	+/-	grey	+	+/-	-	+
14	G	D4	+	-	+	+/-	-	+/-	+/-	-	++ floc
15	G	Polybac	+/-	-	+/-	+/-	grey	+/-	+/-	-	+ floc
16	G5	D5	+/-	-	+	++	-	+	+/-	-	+ floc
17	DNB	D5	+	-	++	+++ floc	grey	+++	+++ floc	-	+++ floc
18	NIH	D5	n/a	n/a	n/a	++	grey	++	+++	-	++
19	G5	D6	+/-	grey	+	+/-	-	+	+	-	+
23	G5	D7	+/-	-	+	+/-	grey	++	+/-	-	+
24	G5	D8	+/-	-	+	+	-	+	+/-	-	+ floc
25	G5	D9	+/-	-	+/-	+/-	-	+	+/-	-	+
26	G5	D10	+/-	-	+/-	+/-	-	+	+/-	-	+
27	G5	D11	+/-	-	+	+/-	-	+	+/-	-	+
28	G5	456	+/-	-	+	+/-	-	++ floc	+/-	-	+ floc

-: No growth
 +/-: Slight growth (turbidity)
 +, ++, +++: Growth (turbidity)

grey, black: Coloration of sand
 floc: Particulate or stringy growth

Culture Studies

Viscosity and polymer production results are shown in Table 23. Culture 33 had the highest viscosity, hence the most polymer production.

Table 23. Viscosity and polymer description of isolates.

Isolate	Product	Viscosity (cP)
Circle 1	Biomass	1.6
AA	Flocculent	1.2
41A	Polymer	5.6
33	Polymer	14.7

Nitrogen Sources

Results for the nitrogen source experiment are shown in Table 24. The AA culture exhibited the best growth with most of the nitrogen sources and was used for further tests.

Table 24. Growth of strains with various nitrogen sources.

Nitrogen source	33	Circle 1	41A	AA	None
None	- p	- p	- p	+/- p	- p
NH ₄ NO ₃	-	+	-	+ sp	- p
NaNO ₃	-	+	- p	+ sp	- p
NH ₄ Cl	-	+	-	-	- p
NaNO ₃ •NH ₄ Cl	-	+	+/- p	+ sp	- p
NaNO ₂	-	-	+/- p	+ sp	- p
Urea	+ rp	+	+ rp	+ rp	- p
Alanine	-	+	+/- p	+	- p

+ = growth
 = no growth
 rp – ropy-looking precipitate
 +/- = may be growth or chemical precipitate
 p = precipitate
 sp = sticky precipitate

The use of nitrate as the representative nitrogen source was selected for flooding studies since it functioned successfully as the alternate electron acceptor salt. Although only nitrate was used in many of the tests, the use of the Maxwell formulations, which provides both the synergistic action of sulfide suppression coupled with increased oil recovery, was shown to provide a greater beneficial effect in field tests.

Carbon sources

Results for the carbon source experiment are shown in Table 25.

Table 25. Growth of strains with various carbon sources.

Carbon source	33	Circle 1	41A	AA	None
Acetate 10%	-	-	-	+	-
Acetate 1%	-	+ p	-	+	-
Acetate 0.1%	-	+ p	+/- p	+ sp	-
Lactate 10%	-	-	-	-	-
Lactate 1%	-	+	+/- p	+	-
Lactate 0.1%	-	+	+ p	+	-
Glucose 10%	+ sp	-	-	+ sp	-
Glucose 1%	+	+ sp	+	+ sp	-
Glucose 0.1%	-	+	+ rp	+	-
Sucrose 10%	+++ rp	+	+++ sp	+++ sp	-
Sucrose 1%	+ rp	+	+ sp	+	-
Sucrose 0.1%	-	+	+/- sp	-	-

+ = growth
 = no growth
 rp – ropy-looking precipitate

+++ = very good growth
 p = precipitate
 sp = sticky precipitate

+/- = may be growth or chemical precipitate

The addition of 10% sucrose increased growth of the cultures considerably, nevertheless acetate and lactate also supported growth at the lower concentrations expected in the reservoir brines. As a consequence, acetate was selected to be used for flooding tests since it had been identified as the major natural carbon component in field waters and would be most representative of the carbon source expected to be present and used at field conditions and operations.

Nutrient Studies

Good microbial growth (see Table 26) was observed in Nutrients 1, 2, 3, 5, and 7, whose composition is identified in Table 8. Variations based on these nutrients were used and the concentrations reduced to determine the minimum amounts needed for growth and production of desired microbial products.

Table 26. Growth results.

	First series	Second series
Nutrient 1	slightly turbid, tiny white particles, lots of rods	slightly turbid, no particles, lots of rods
Nutrient 2	slightly turbid, tiny white particles, lots of rods	slightly turbid, precipitate, small white particles, lots of rods
Nutrient 3	slightly turbid, small white particles, no bacteria	precipitate, small white particles, lots of rods
Nutrient 4	clump of biomass? no bacteria	precipitate, small white particles, no bacteria
Nutrient 5	slightly turbid, small white particles, lots of rods	precipitate, small white particles, lots of rods
Nutrient 6	not turbid, no particles, no bacteria	precipitate, small white particles, no bacteria
Nutrient 7	slightly turbid, lots of rods	precipitate, some small white particles, some rods, not as many as the other nutrients
Nutrient 8	not turbid, no bacteria	precipitate, small white particles, no bacteria

Flooding Culture Consortium

The majority of flooding tests used a California reservoir microbial consortium due to this population’s capacity to clearly use and need only the acetate as the carbon source. Many of the other cultures required additional nutrient fortification. However this is not to imply that the reported results occurred only with this consortium of microorganisms, since many other isolated indigenous cultures performed equally as well and similar results would be expected in most reservoir indigenous microflora systems.

Nutrient T

The addition of Nutrient T to California brines resulted in the production of large quantities of gas which increased with time. Results for the 55° C bottle tests, which gave better results than the 35° C tests, are shown in Figures 3-6. The data shown is cumulative gas production over time. Sampling for the liquid bionutrient T system was discontinued after one month because the dry system had a greater increase in gas production. It should be noted that gas production occurred in many of the most successful oil recovery tests and indicated that gas production is one mechanism that would be beneficial for increased oil recovery. The high gas-producing potential of Nutrient T strongly suggests that its addition, especially to heavy oil reservoirs, would encourage increased oil recovery and would indicate, as observed with the example of polymer production, that a microbial population can be directed to produce a predominant oil recovery agent. However, in the reservoir the effects of all microbial products can be expected and should function as in a combined system to increase oil release and recovery.

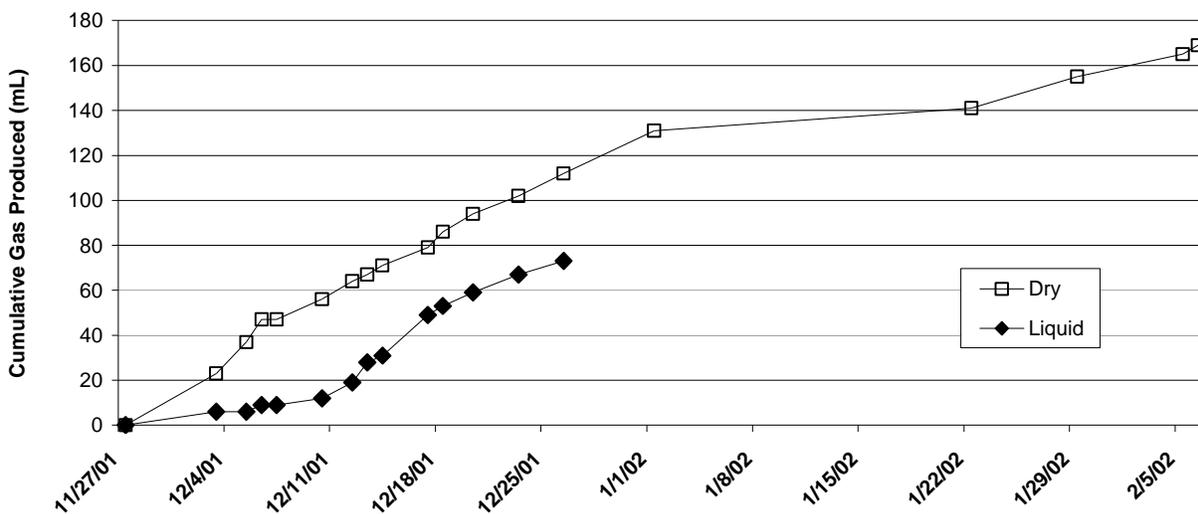


Figure 3. Comparison of gas production of dry vs. liquid Nutrient T in Tulare produced brine.

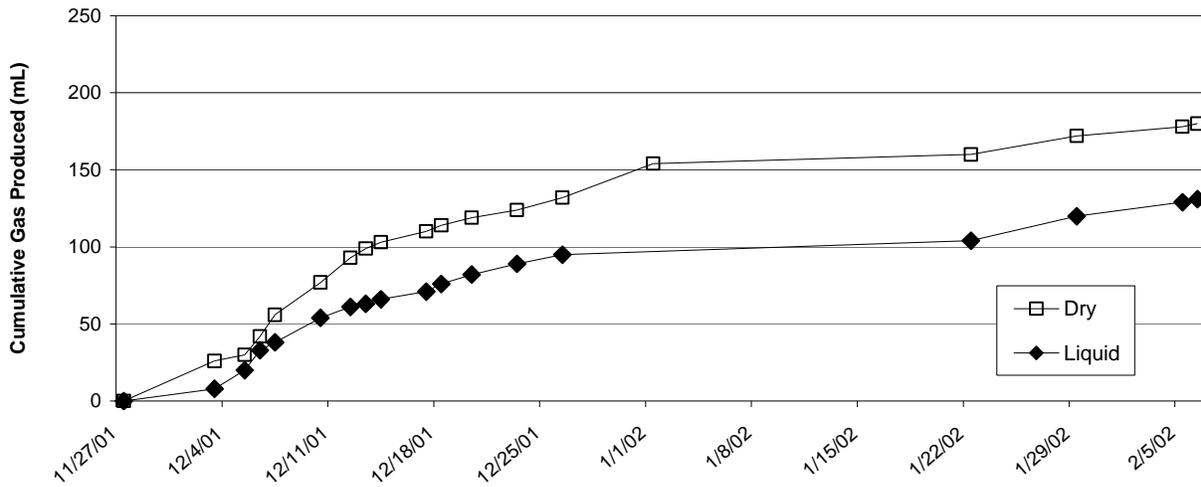


Figure 4. Comparison of gas production of dry vs. liquid Nutrient T in Tulare aquifer water.

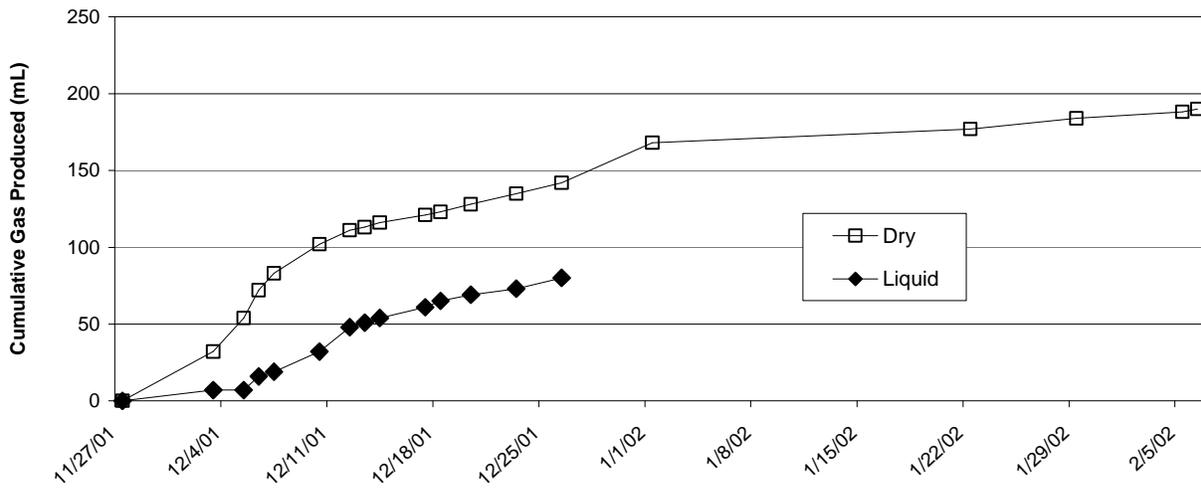


Figure 5. Comparison of gas production of dry vs. liquid Nutrient T in Ventura brine.

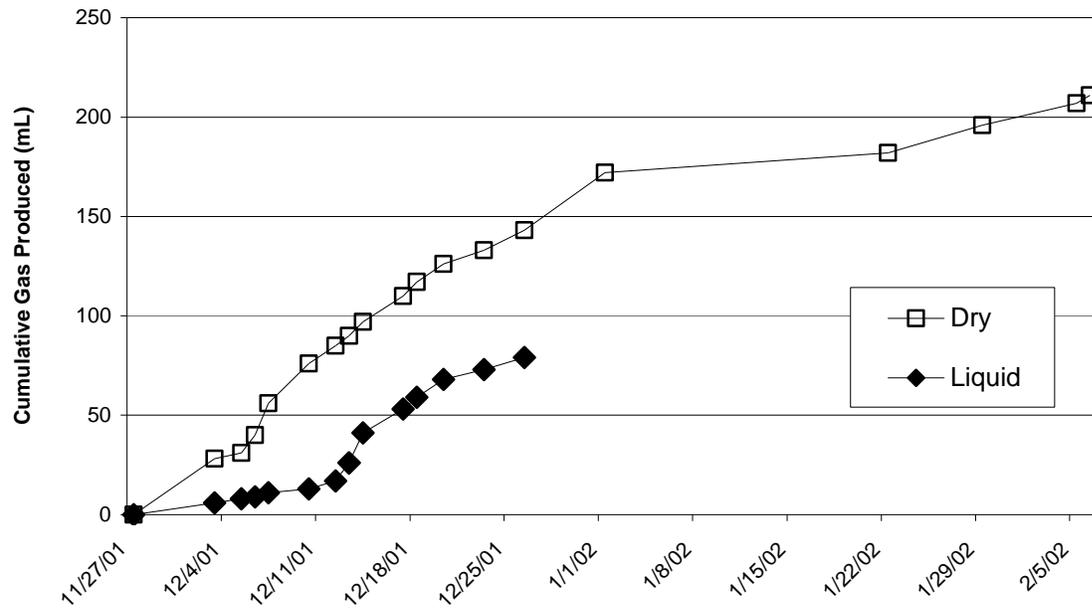


Figure 6. Comparison of gas production of dry vs. liquid Nutrient T in Diatomite brine.

Flooding Tests Results

A series of multiple sandpack columns was tested for reduction in permeability due to various nutrient formulations. These sandpacks were also tested for increased oil recovery.

Treatment with DNB broth without nitrate stimulated polymer production which reduced the sandpack permeability from 10.4 darcies to 8.1 darcies, as shown in Figure 7.

Treatment with DNB broth stimulated polymer production in PB-3 which reduced the sandpack permeability from 12.6 darcies to 0.6 darcies, as shown in Figure 8. This demonstrates that the addition of nitrate stimulated polymer production, as compared with the flood in which no nitrate was added, as shown in Figure 7.

Treatment with DNB broth containing 10% sucrose also stimulated polymer production in PB-1, reducing the permeability from 11.1 darcies to 5.5 darcies, as shown in Figure 9.

The results show that the addition of nitrate increased the reduction in permeability which would favor oil recovery significantly. The addition of sucrose resulted in earlier formation of the polymer as determined by PV measurements.

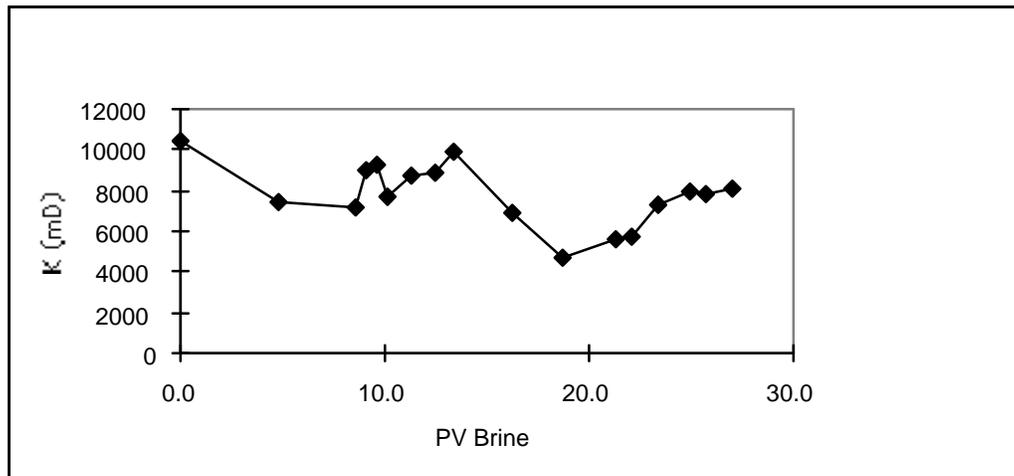


Figure 7. Permeability Reduction in Sandpack PB-2 treated with DNB without nitrate.

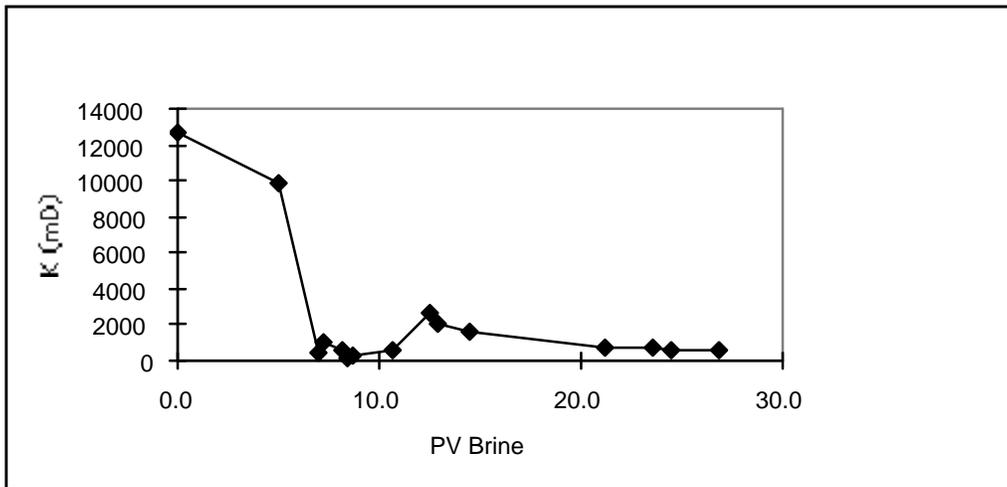


Figure 8. Permeability Reduction in Sandpack PB-3 treated with DNB broth containing nitrate.

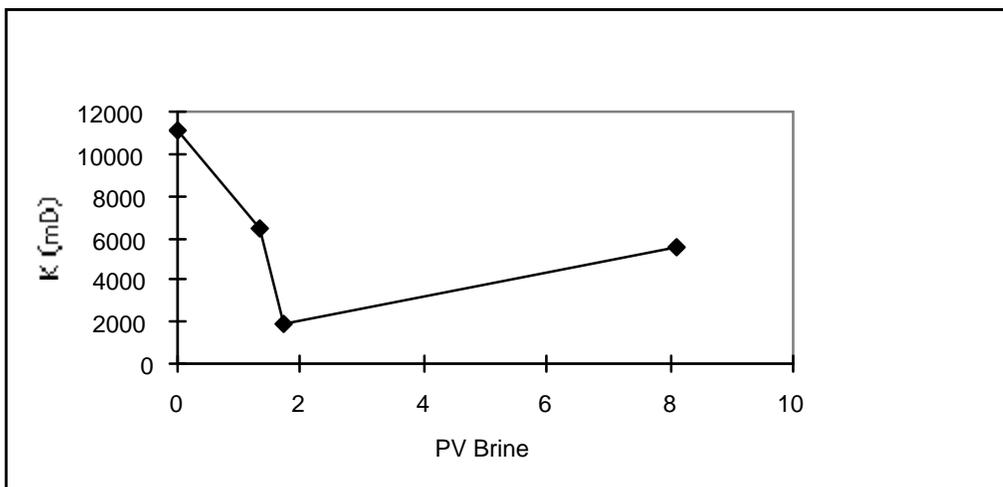


Figure 9. Sandpack PB-1 treated with DNB broth containing nitrate and sucrose.

P-4 and P-6 Sandpack Results

The permeability of both packs was reduced substantially by in-situ polymer production by the injected microbial cultures, as shown in Table 27. The permeability in P-4 was reduced by 41%, and the permeability in P-6 was reduced by 38%. It is postulated that the nitrate media stimulated polymer production and permeability reduction could be one effective mechanism for increased oil recovery. These results emphasize that the culture inoculum is critical in the formation of the polymer and permeability reduction observed in the flooding tests. Thus, while culture A1 and 1 reduced the permeability about 40% with nitrate present, culture 33 with nitrate had a much greater effect.

Table 27. Permeability reduction.

Sand pack #	Inoculum Culture	Treatment	Original Permeability (D)	Final Permeability (D)	Reduction in Permeability (%)
PB-1	33	DNB medium+ sucrose	11.1	5.5	50
PB-2	33	DNB medium without nitrate	10.4	8.1	22
PB-3	33	DNB medium	12.6	0.6	95
P-4	A1	DNB medium	3.9	2.3	41
P-6	1	DNB medium	6.6	4.1	38

These results were confirmed by a parallel sand pack flood as shown in Figure 10. The flow rate for the nitrate treated pack, PI-29, was substantially reduced due to polymer production by the injected bacteria.

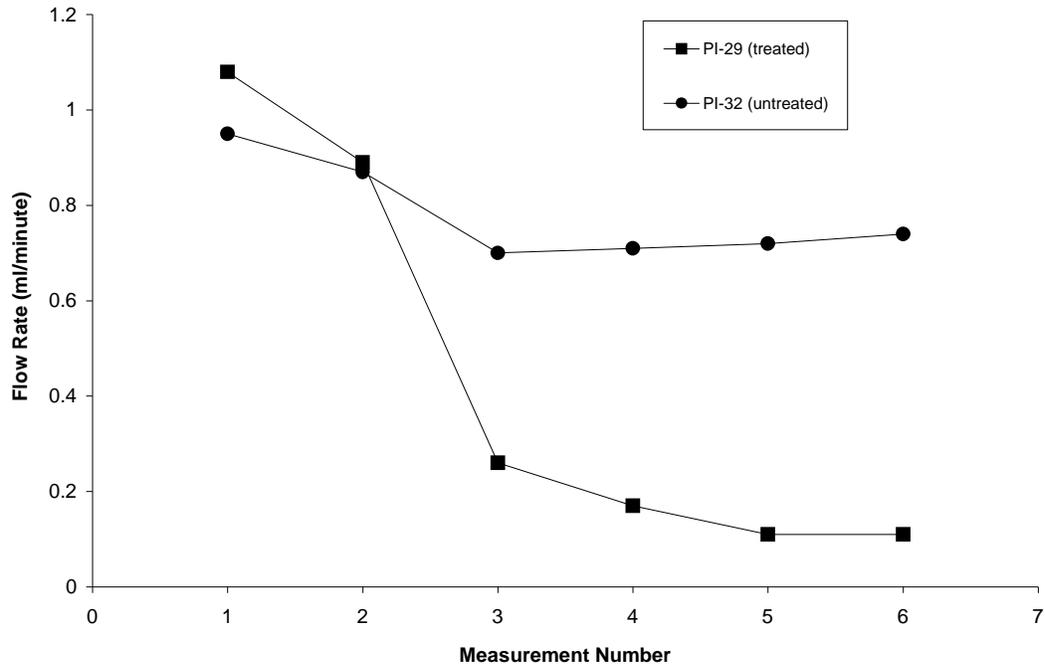


Figure 10. Flow rate reduction due to biopolymer production

Oil Recovery Tests

PI-1 through PI-8a Corefloods

The effect of nitrate and acetate supplementation to floodwaters and their effect on oil recovery demonstrated that the presence of both compounds gave increased oil recovery with the best recovery increase in sandpacks which had the most potential for increased recovery. Table 28 shows the oil recovery results. In this experiment, no additional oil was produced without the addition of both nitrate and acetate, demonstrating that these nutrients are essential for oil recovery in this system.

Table 28. Sand packs PI-1 through PI-8a oil recovery results.

Sand pack #	Waterflood Recovery (%)	Treatment Type	Treatment Recovery (%)
PI-1	104.4	0 ppm acetate 0 ppm nitrate	0.0
PI-3	67.0	500 ppm acetate 0 ppm nitrate	0.0
PI-4	45.4	1000 ppm acetate 0 ppm nitrate	0.0
PI-5	85.8	0 ppm acetate 100 ppm nitrate	0.0
PI-7	67.0	500 ppm acetate 100 ppm nitrate	18.7
PI-8	96.3	1000 ppm acetate 100 ppm nitrate	9.2
PI-8a	69.2	1000 ppm acetate 100 ppm nitrate	7.5

PB-8 through PB-14 Corefloods

PB-8 produced an additional 3 ml of oil, for a final oil recovery of 94.3%. PB-9 produced an additional 1.65 ml of oil, for a final oil recovery of 98.5%. Results are shown in Table 29 and in Figures 11 and 12. This experiment demonstrates that the addition of nitrate stimulated the bacteria to produce additional oil.

Table 29. Sand packs PB-8 and PB-9 oil recovery results.

Core #	Waterflood Recovery (%)	Treatment Type	Treatment Recovery (%)	Final Recovery (%)
PB-8	75.5	1180 ppm acetate 1240 ppm nitrate	18.8	94.3
PB-9	81.6	1180 ppm acetate 1240 ppm nitrate	16.9	98.5

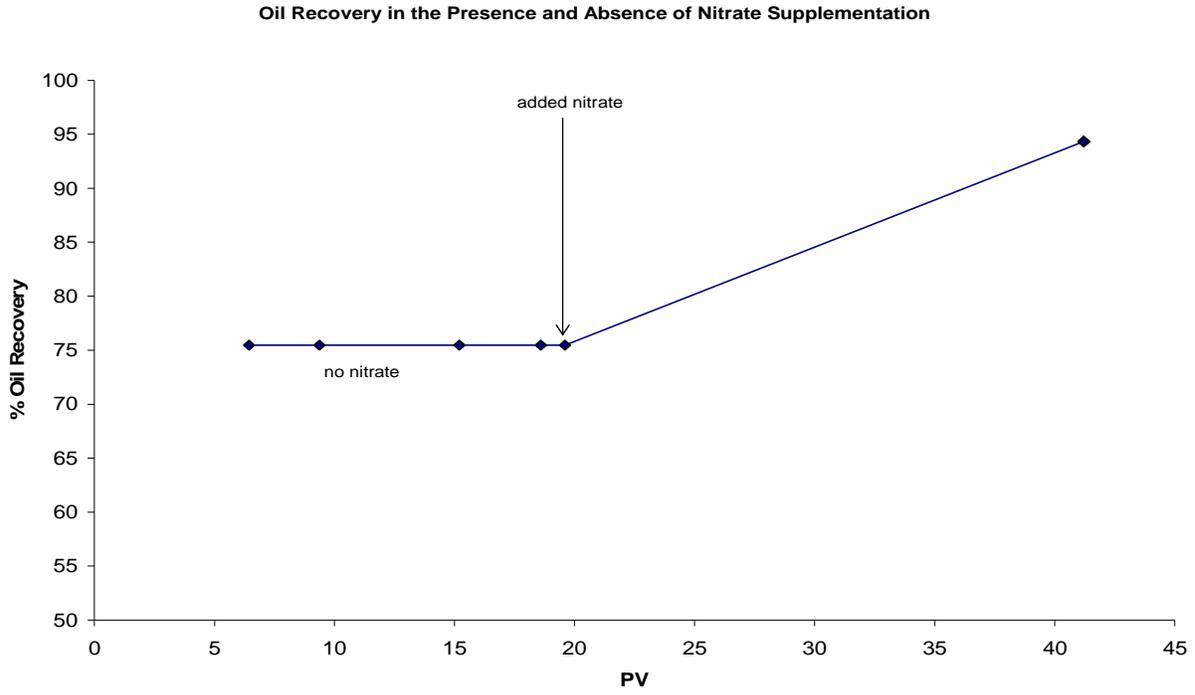


Figure 11. Sand pack PB-8 treated with nitrate.

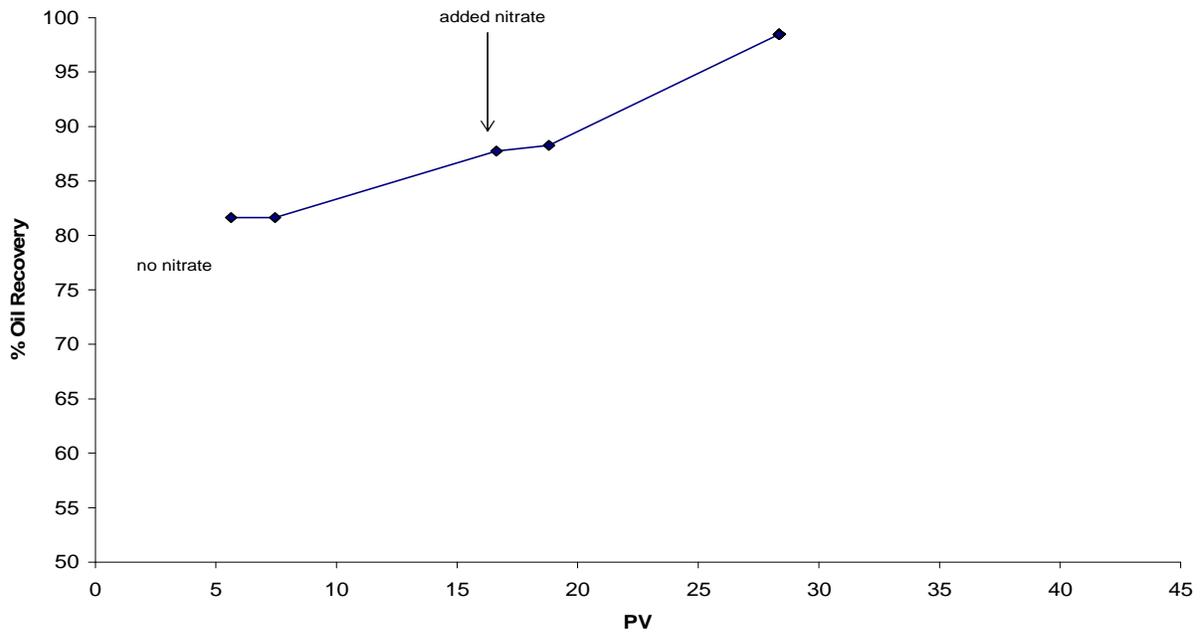


Figure 12. Sand pack PB-9 treated with nitrate.

Table 30 and Figure 13 show the oil recovery results for PB-10 through PB-14. The addition of phosphate along with nitrate stimulated the bacteria to produce additional oil.

Table 30. Sand packs PB-10 through PB-14 oil recovery results.

Sand pack #	Waterflood Recovery (%)	Treatment Type	Final Recovery (%)	Treatment Recovery (%)
PB-10	85.9	1180 ppm acetate	85.9	0.0
PB-11	66.1	1180 ppm acetate 100 ppm nitrate 100 ppm phosphate	80.7	14.6
PB-12	61.0	1180 ppm acetate 1000 ppm nitrate 100 ppm phosphate	80.0	19.0
PB-13	75.0	1180 ppm acetate 100 ppm nitrate	75.0	0.0
PB-14	62.5	1180 ppm acetate 1000 ppm nitrate	63.5	1.0

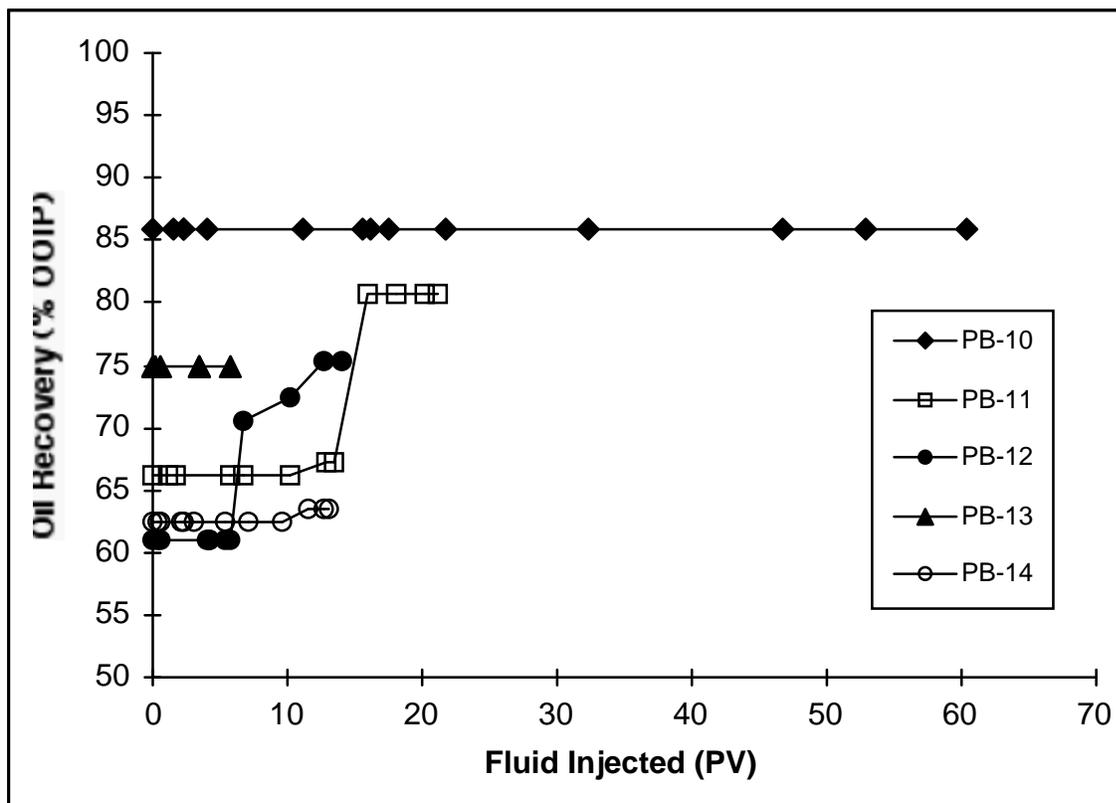


Figure 13. Sand packs PB-10 through 14 oil recovery results.

PI-17 through PI-24 Corefloods

Results for PI-17 through PI-24 are shown in Table 31. Oil recovery is not as high with this inoculation strategy as it was when DNB broth was used. This set of packs did not give consistent results.

Table 31. Sand packs PI-17 through PI-24 oil recovery results.

Sand pack #	Waterflood Recovery (%)	Treatment Type	Final Recovery (%)	Treatment Recovery (%)
PI-17	81.6	0 ppm acetate 0 ppm nitrate 100 ppm phosphate	82.1	0.5
PI-18	66.2	100 ppm acetate 0 ppm nitrate 100 ppm phosphate	70.9	4.7
PI-19	65.0	500 ppm acetate 0 ppm nitrate 100 ppm phosphate	65.5	0.5
PI-20	68.1	1000 ppm acetate 0 ppm nitrate 100 ppm phosphate	72.7	4.6
PI-21	67.9	0 ppm acetate 1000 ppm nitrate 100 ppm phosphate	67.9	0.0
PI-22	73.2	100 ppm acetate 1000 ppm nitrate 100 ppm phosphate	75.5	2.3
PI-23	68.5	500 ppm acetate 1000 ppm nitrate 100 ppm phosphate	74.1	5.6
PI-24	67.6	1000 ppm acetate 1000 ppm nitrate 100 ppm phosphate	70.3	2.7

In most of the floods that were conducted, the addition of acetate and nitrate was necessary to stimulate microbial activity and increase oil production. Some results were inconsistent, and further study was needed to determine optimum nutrient concentrations and injection protocol.

PI-26 through PI-42 Corefloods

Sand packs PI-26 through 30 and PI-39 through 42 were shut in overnight, then waterflooded with Instant Ocean mixed with the nutrients listed in Table 32, which shows the oil recovery results for the sand packs. Results for PI-39 through 42 are also shown in Figure 14.

Table 32. Sand packs PI-26 through 30 and PI-39 through 42 oil recovery results.

Sand pack #	Waterflood Recovery (%)	Treatment Type	Final Recovery (%)	Treatment Recovery (%)
PI-26	66.2	0 nitrate, 100 acetate	71.8	5.6
PI-27	63.4	100 nitrate, 0 acetate	64.3	0.9
PI-28	71.7	100 nitrate, 100 acetate	72.8	1.1
PI-29	65.8	100 nitrate, 500 acetate	67.5	1.7
PI-30	58.0	100 nitrate, 1000 acetate	58.9	0.9
PI-39	70.0	0 nitrate, 0 acetate	72.0	2.0
PI-40	66.1	1000 nitrate, 0 acetate	70.7	4.6
PI-41	70.0	0 nitrate, 1000 acetate	70.9	0.9
PI-42	64.0	1000 nitrate, 1000 acetate	78.5	14.5

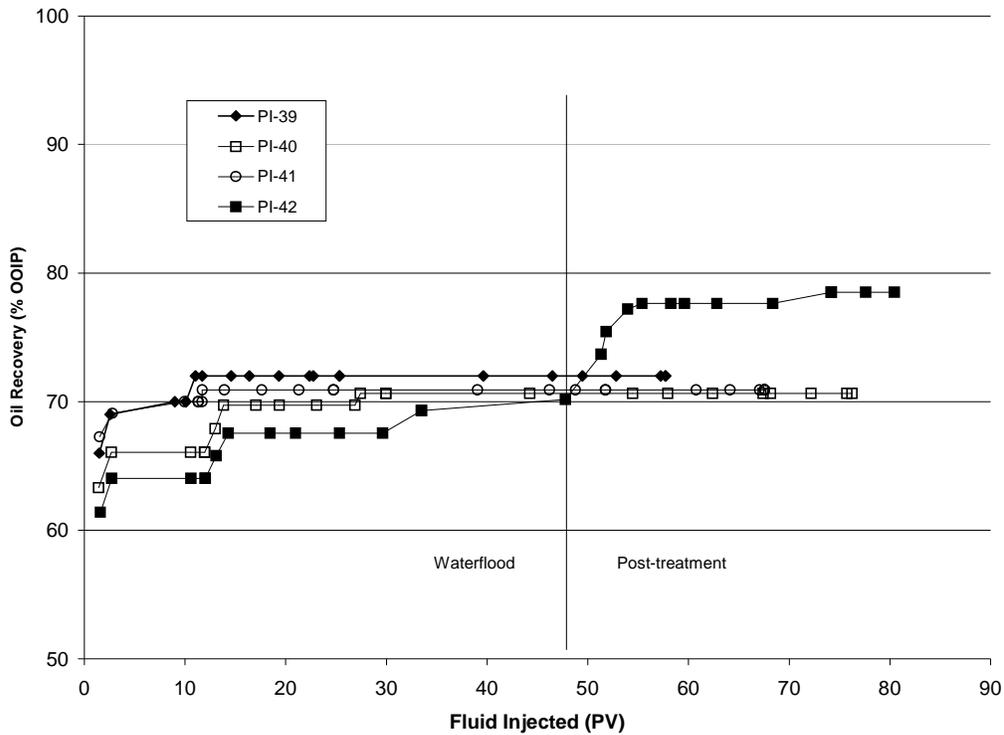


Figure 14. Oil recovery results for PI-39 through PI-42.

PH Corefloods using Field Brines

Figure 15 shows the oil recovery results for PH-1 and PH-2. The PH-2 flood with Max-Well Waterflood Treatment increased the oil production by 2.3%.

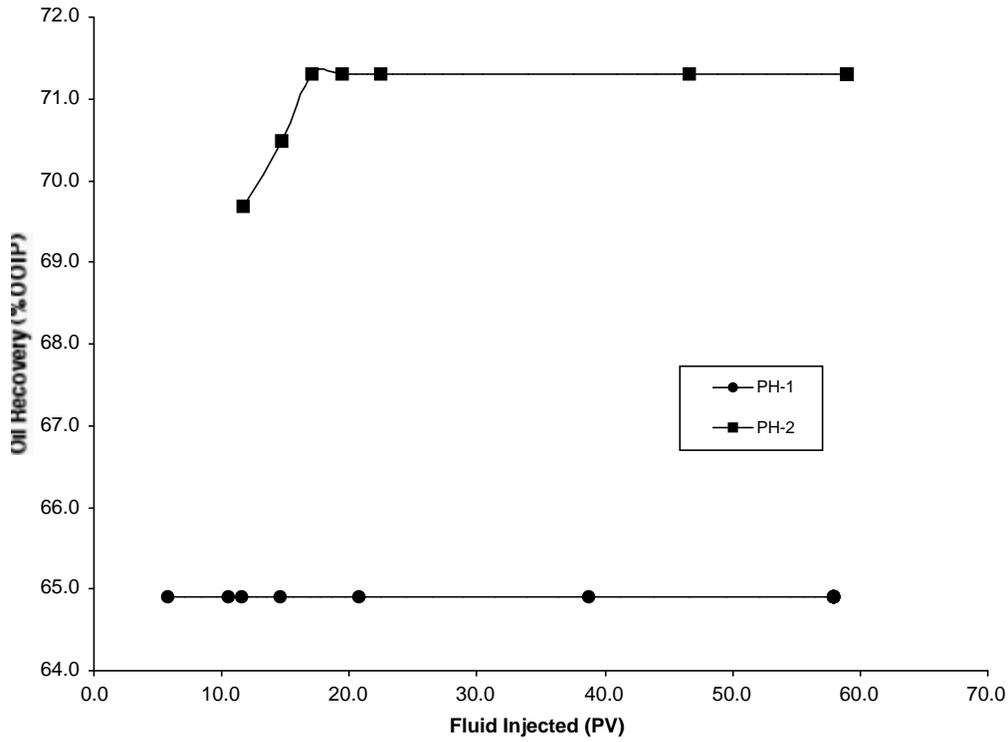


Figure 15. Sand packs PH-1 and 2 oil recovery results.

Large Sandpack Flooding Tests

Results of the initial 10 foot sand pack flood are shown in Figure 16. Oil production was increased from 77.5% by waterflooding alone to 80.7% after nutrient treatment was begun on February 26.

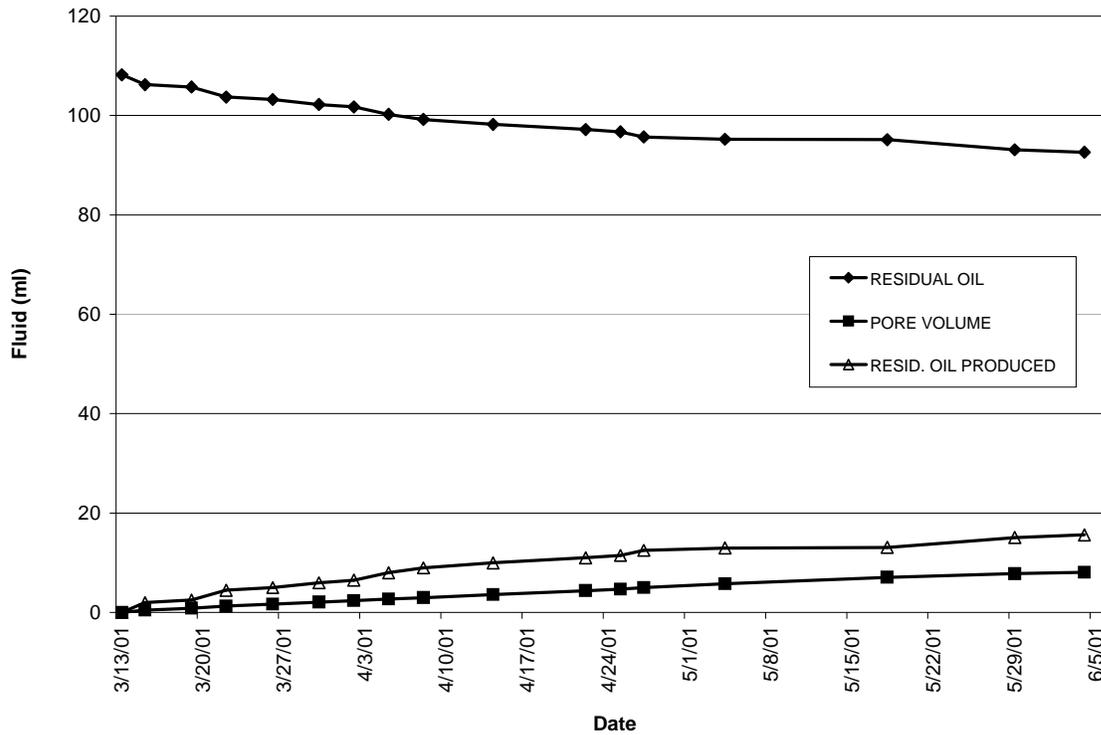


Figure 16. 10 ft. sand pack microbial flood.

Heavy Oil (HO) Corefloods

Results for the three sand pack floods with heavy oil are shown in Figures 17-19. Maxwell treatment did not result in increased recovery, but Nutrient T was effective in stimulating heavy oil recovery. Final oil recovery for sand pack HO-101 was 93% of OOIP, for HO-102 the oil recovery was 94%, and for HO-103 the oil recovery was 61%.

Coreflood Number	Final Oil Recovery (% OOIP)
HO-101	93
HO-102	94
HO-103	61

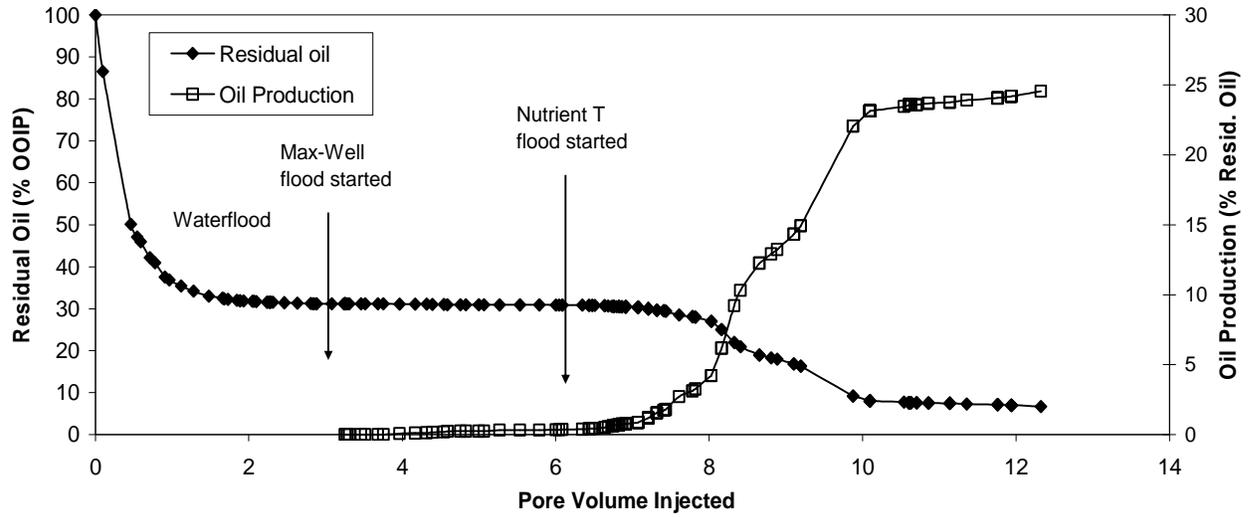


Figure 17. HO-101 sandpack flood.

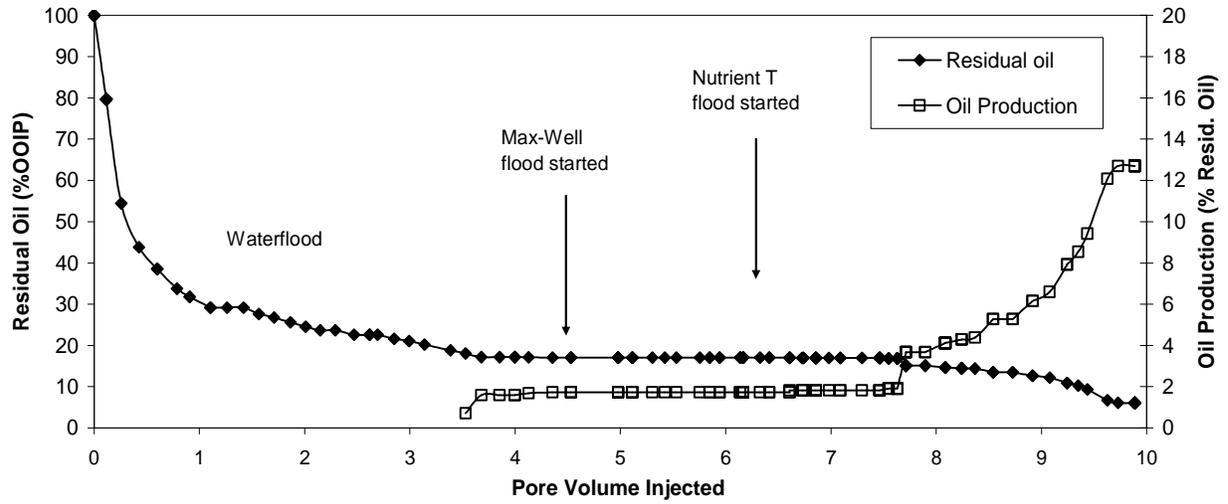


Figure 18. HO-102 sandpack flood.

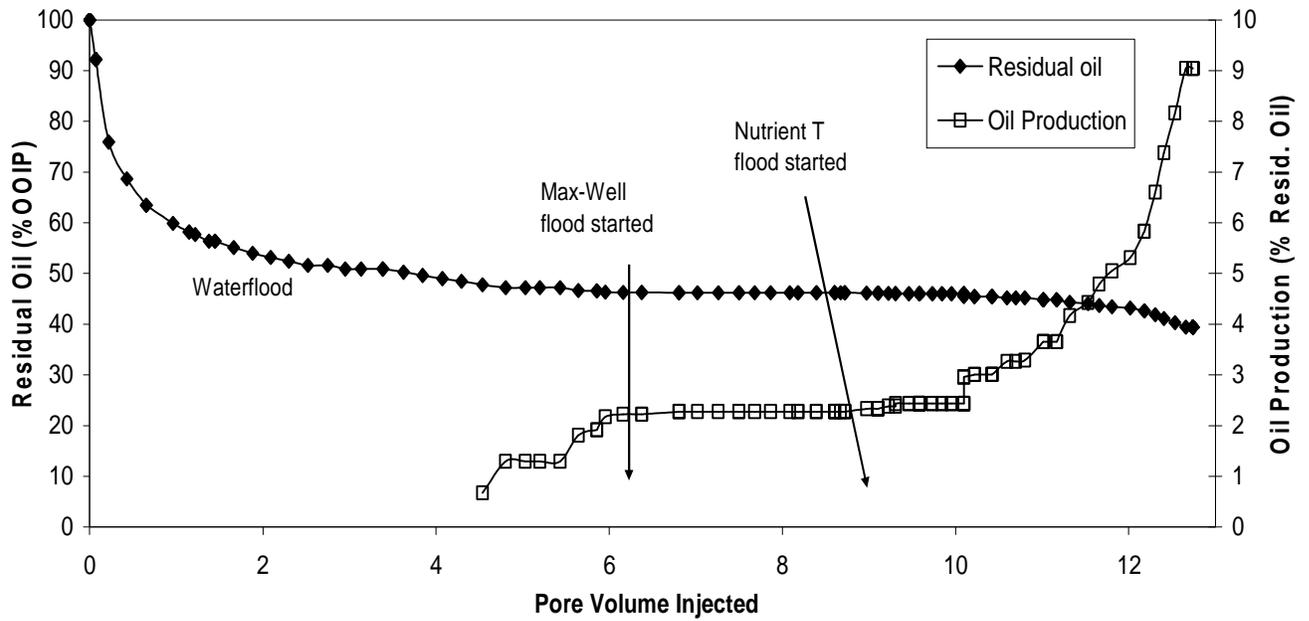


Figure 19. HO-103 sandpack flood.

VSP and RSP Corefloods

Results are shown in Figures 20 – 36 and Table 33. Floods treated with Nutrient T gave the best results of the packs operated in the horizontal position. The pack run in the vertical position with Nutrient T also showed good results.

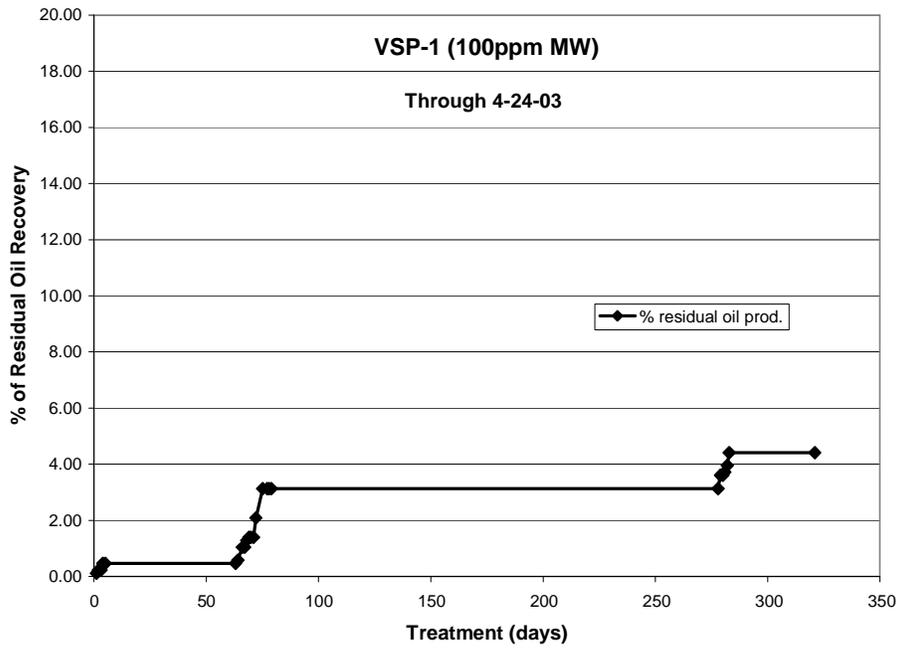


Figure 20. Light Oil Production with Treatment VSP-1, 100 ppm Maxwell.

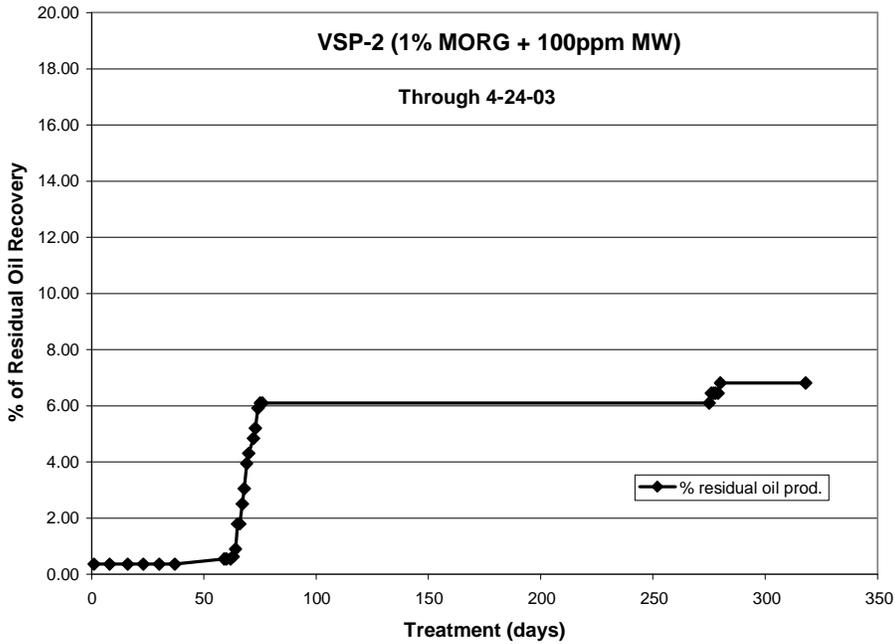


Figure 21. Light Oil Production with Treatment VSP-2, 1% MORG + 100 ppm Maxwell.

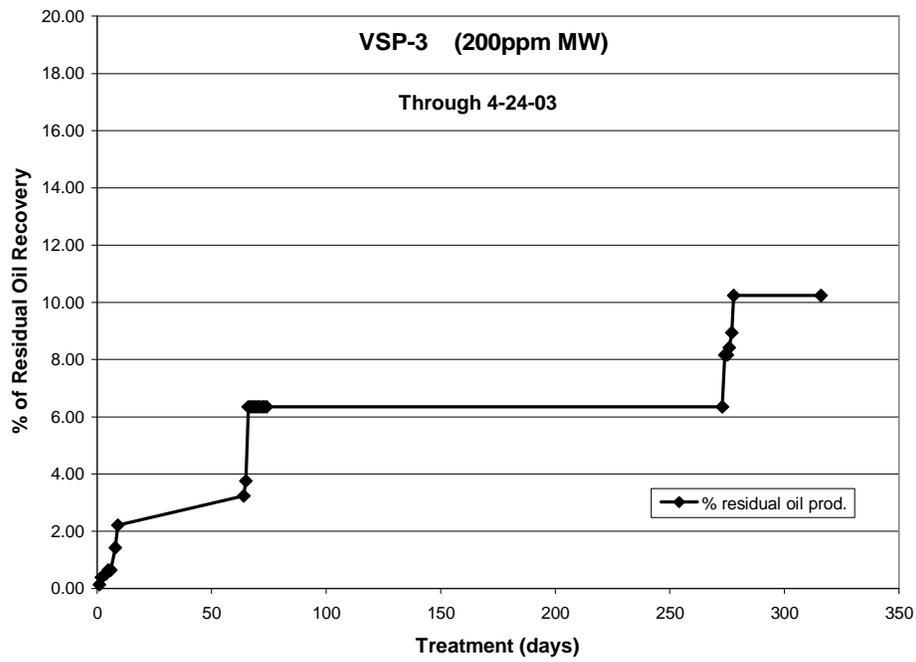


Figure 22. Light Oil Production with Treatment VSP-3, 200 ppm Maxwell.

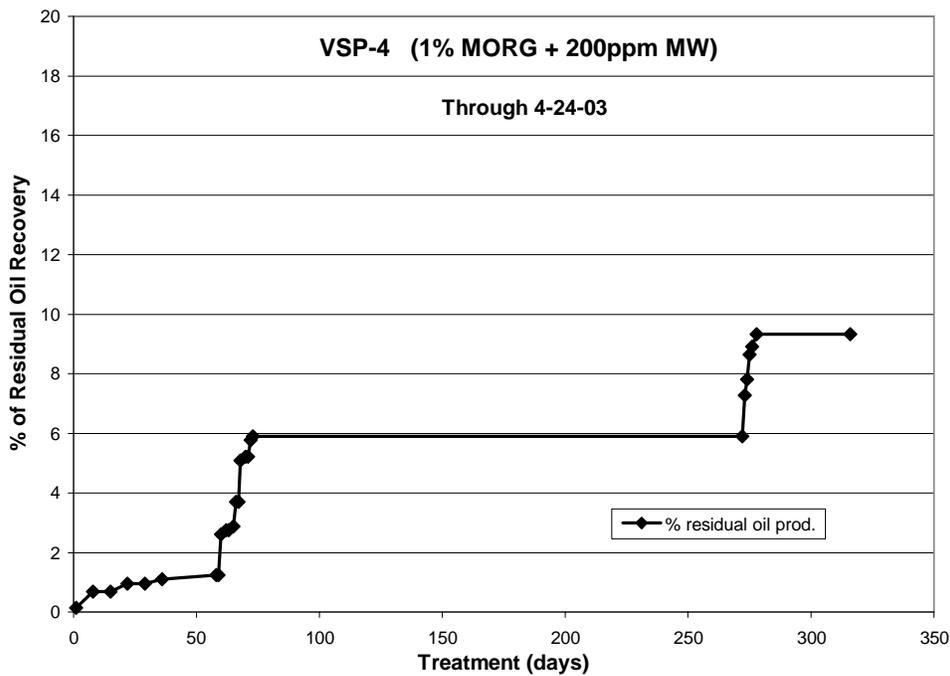


Figure 23. Light Oil Production with Treatment VSP-4, 1% MORG + 200 ppm Maxwell.

VSP-5 (Nutrient T-horizontal)

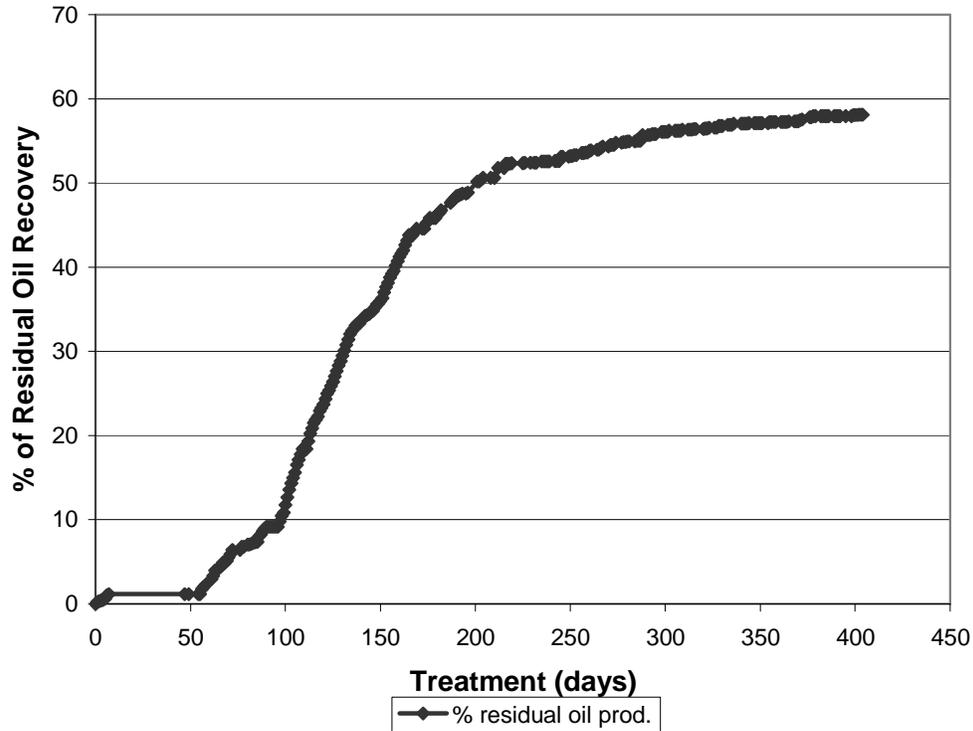


Figure 24. Heavy Oil Production with Treatment VSP-5, Nutrient T.

VSP 6 (Nutrient T-Horizontal)

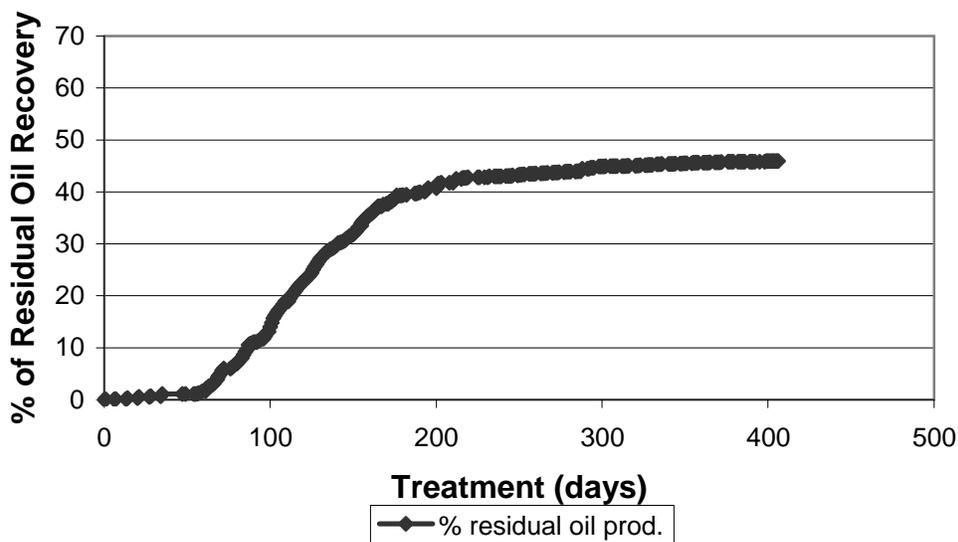


Figure 25. Heavy Oil Production with Treatment VSP-6, Nutrient T.

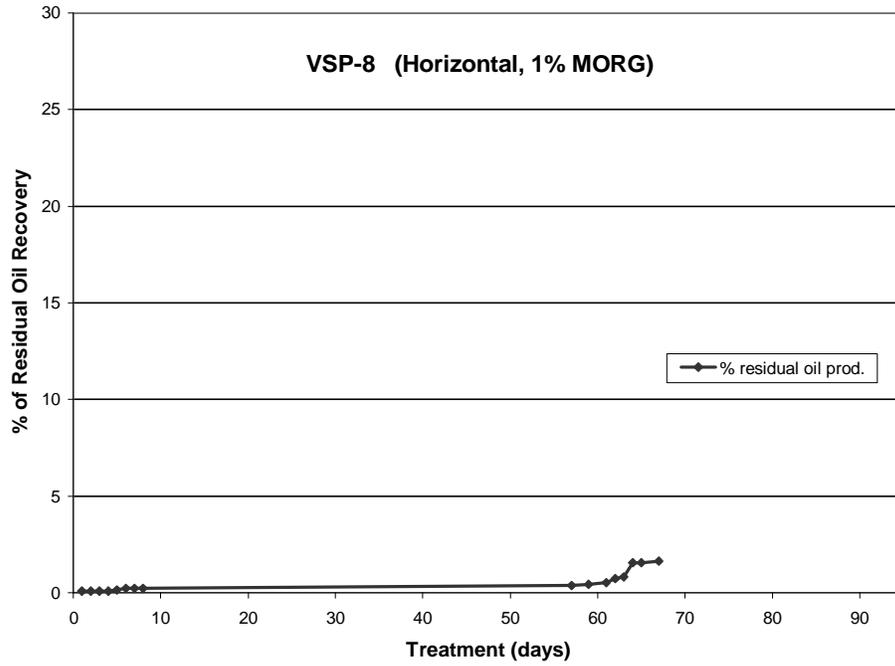


Figure 26. Heavy Oil Production with Treatment VSP-8, 1% MORG.

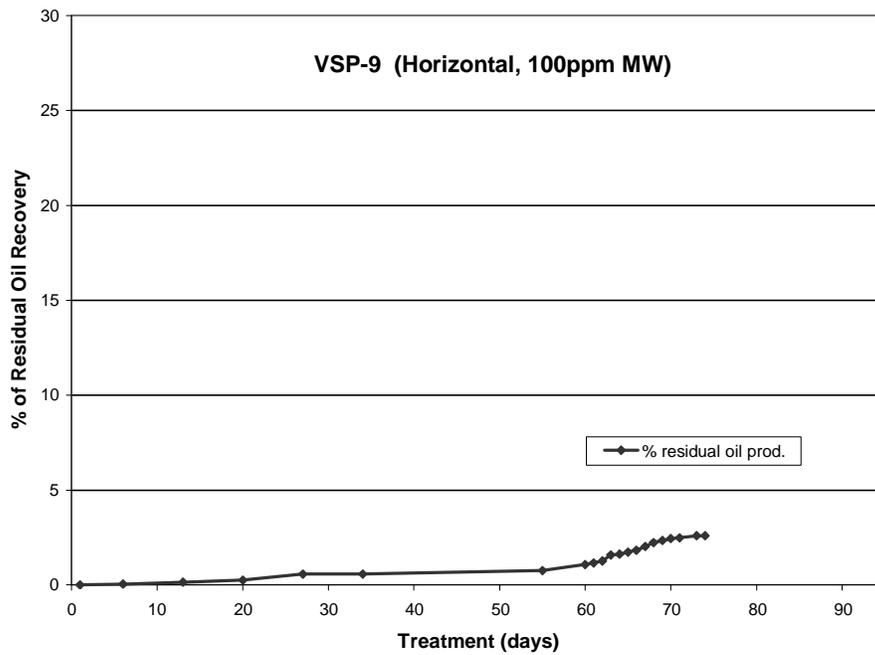


Figure 27. Heavy Oil Production with Treatment VSP-9, 100 ppm Maxwell.

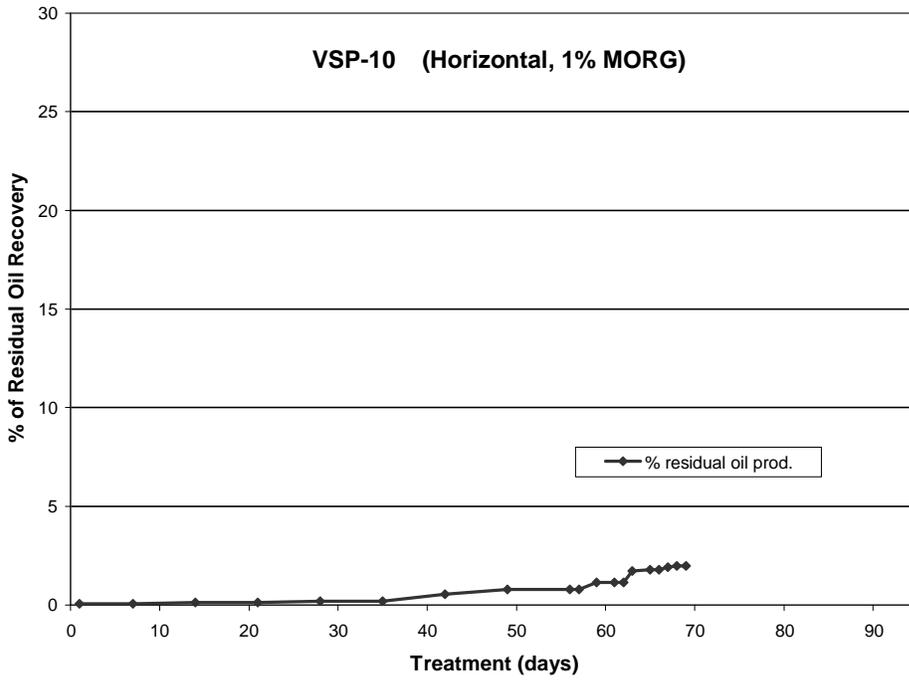


Figure 28. Heavy Oil Production with Treatment VSP-10, 1% MORG.

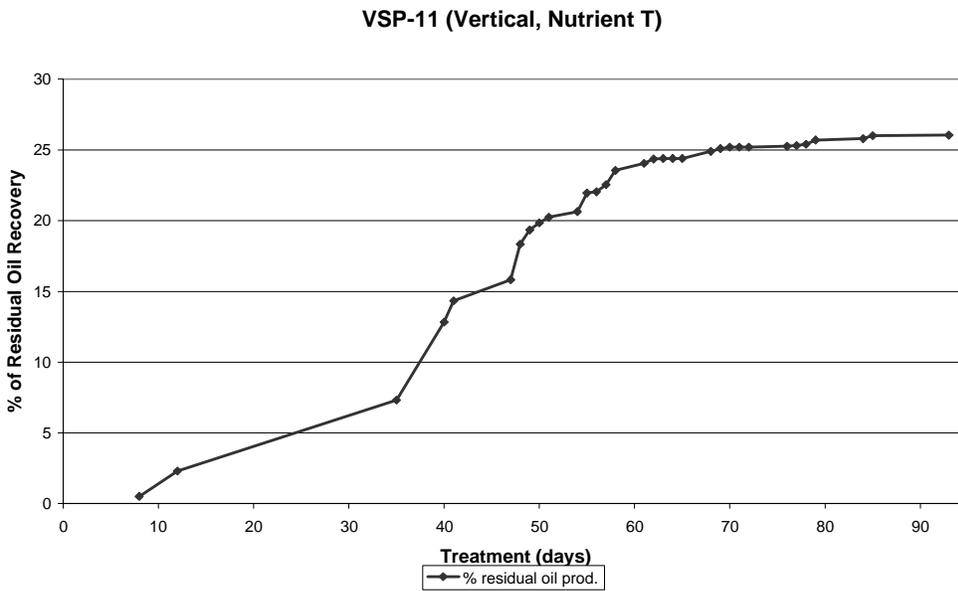


Figure 29. Heavy Oil Production with Treatment VSP-11 Vertical, Nutrient T.

VSP-12 (Vertical, Maxwell)

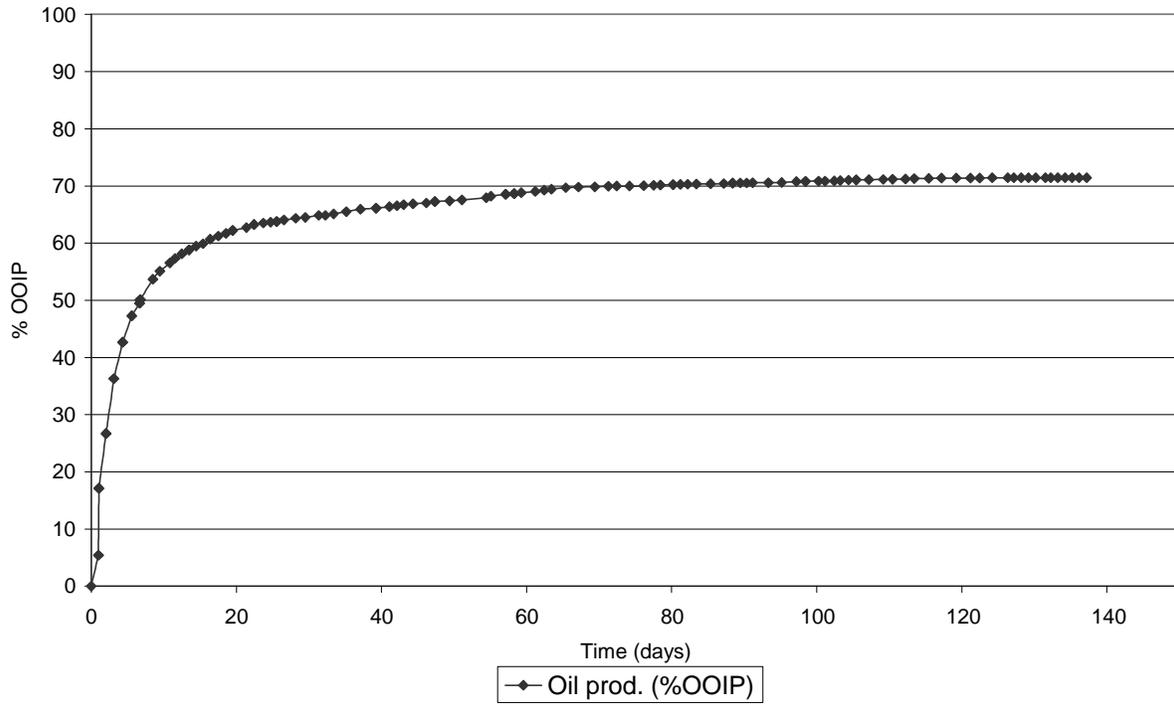


Figure 30. Heavy Oil Production with Treatment VSP-12 Vertical, 100ppm Maxwell intermittent treatment on OOIP.

RSP-C(Nutrient T-vertical)

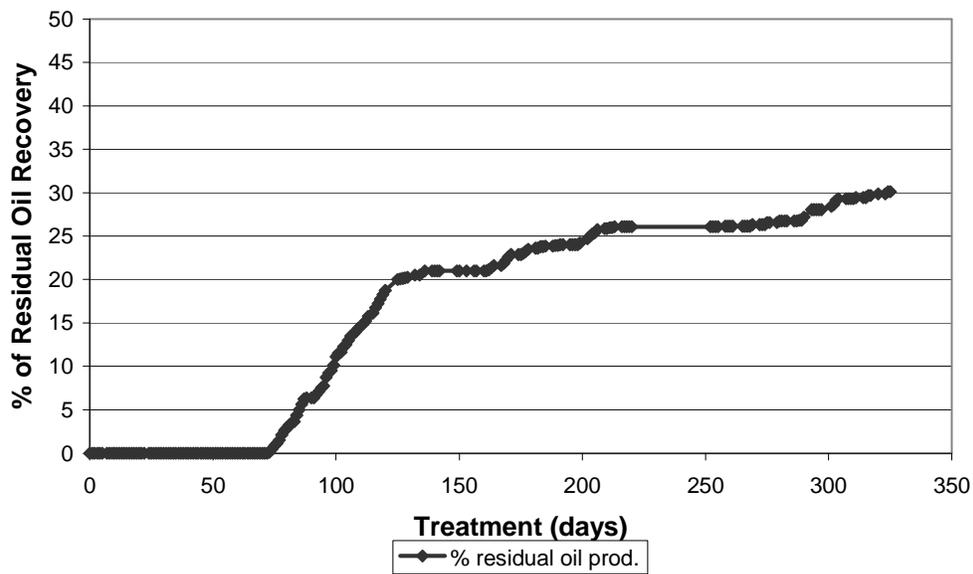


Figure 31. RSP-C Vertical, Tulare Heavy Oil, Nutrient T, Continuous injection.

RSP-E (PE + Maxwell-vertical)

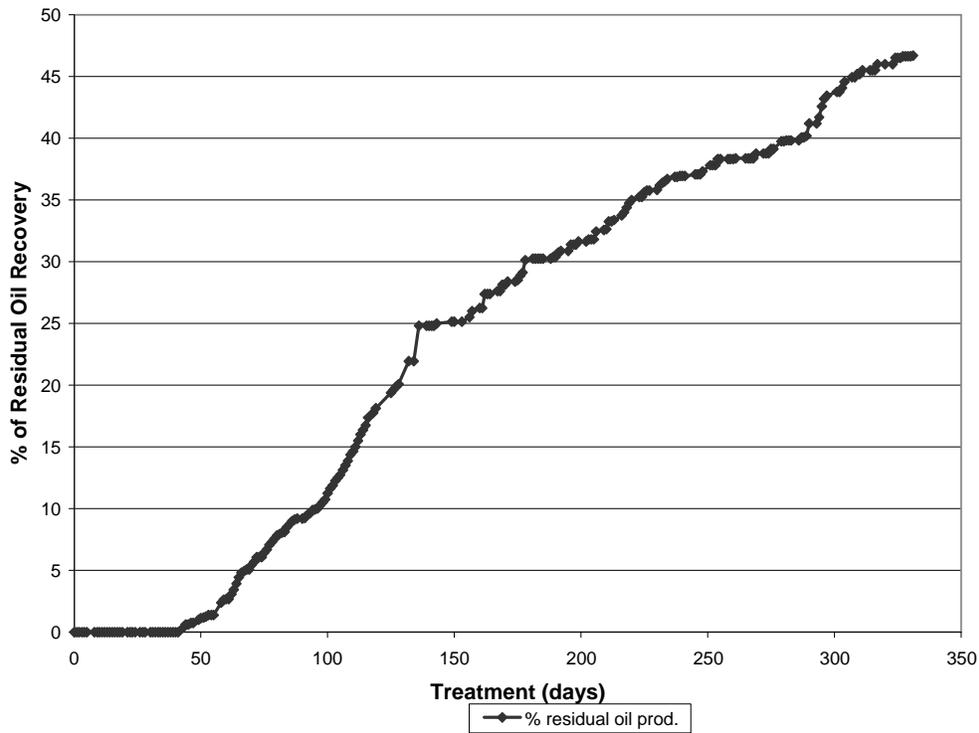


Figure 32. RSP-E Vertical, Tulare Heavy Oil, Nutrient T + Maxwell, Continuous injection.

RSP-F (PE + Maxwell-vertical)

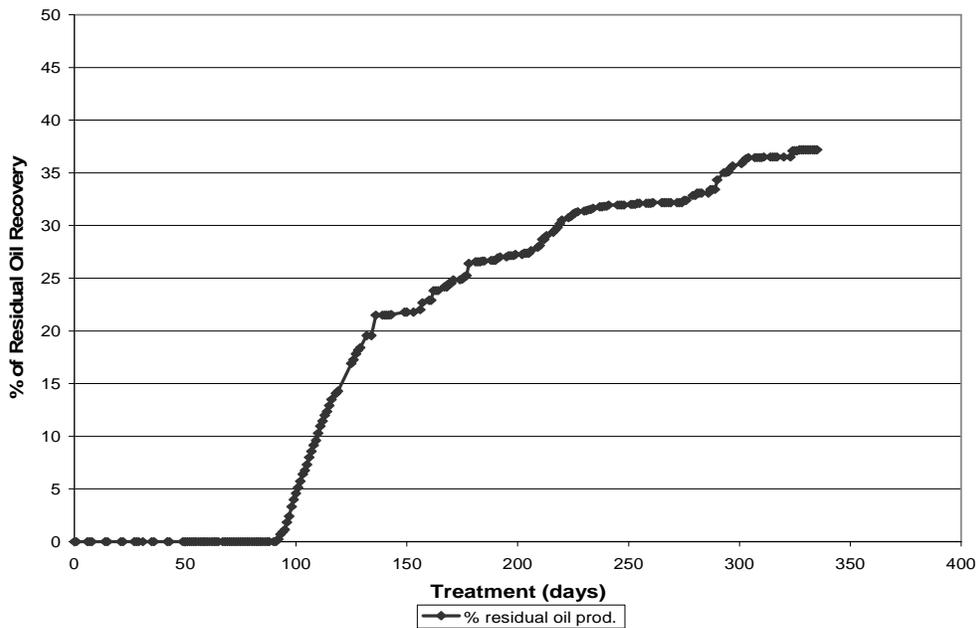


Figure 33. RSP-F Vertical, Tulare Heavy Oil, Nutrient T+ Maxwell, Intermittent injection for 1 PV followed by continuous injection.

Table 33. Coreflood Results

Core Number	Nutrient	Oil Type	Orientation of flow	Flooding Protocol	Days of Treatment	Final Recovery (% Residual)	Final Recovery (% OOIP)
VSP-1	MW	Light	Horizontal	Continuous	79	5.9	76.9
VSP-2	MORG+MW	Light	Horizontal	Continuous	76	6.1	71.3
VSP-3	MW	Light	Horizontal	Continuous	74	2.1	81.5
VSP-4	MORG+MW	Light	Horizontal	Continuous	73	5.9	81.9
VSP-5	Nutrient T	Heavy	Horizontal	Continuous	410	48.3	83.8
VSP-6	Nutrient T	Heavy	Horizontal	Continuous	410	46.1	68
VSP-8	MORG	Heavy	Horizontal	Continuous	67	1.64	61.8
VSP-9	MW	Heavy	Horizontal	Continuous	74	2.6	49.5
VSP-10	MORG	Heavy	Horizontal	Continuous	69	2	55.7
VSP-11	Nutrient T	Heavy	Vertical	Continuous	93	26.1	61.2
VSP-12	MW	Heavy	Vertical	Intermittent	137	N/A	71.5
RSP-A	MW	Heavy	Vertical	Continuous	112	0	N/A
RSP-B	MW	Heavy	Vertical	Intermittent	73	0	N/A
RSP-C	Nutrient T	Heavy	Vertical	Continuous	335	30.2	N/A
RSP-E	Nutrient T+MW	Heavy	Vertical	Continuous	335	47.1	N/A
RSP-F	Nutrient T+MW	Heavy	Vertical	Intermittent	335	37.2	N/A
RSP-G	MORG	Heavy	Vertical	Continuous	106	7.9	N/A
RSP-H	MORG	Heavy	Vertical	Intermittent	109	15.8	N/A

*N/A because RSP Cores were “pre-residualized” (OOIP = Residual Oil) and VSP-12 was treated from OOIP without waterflood to residual.

Nutrient T Floods: VSP-5 and VSP-6

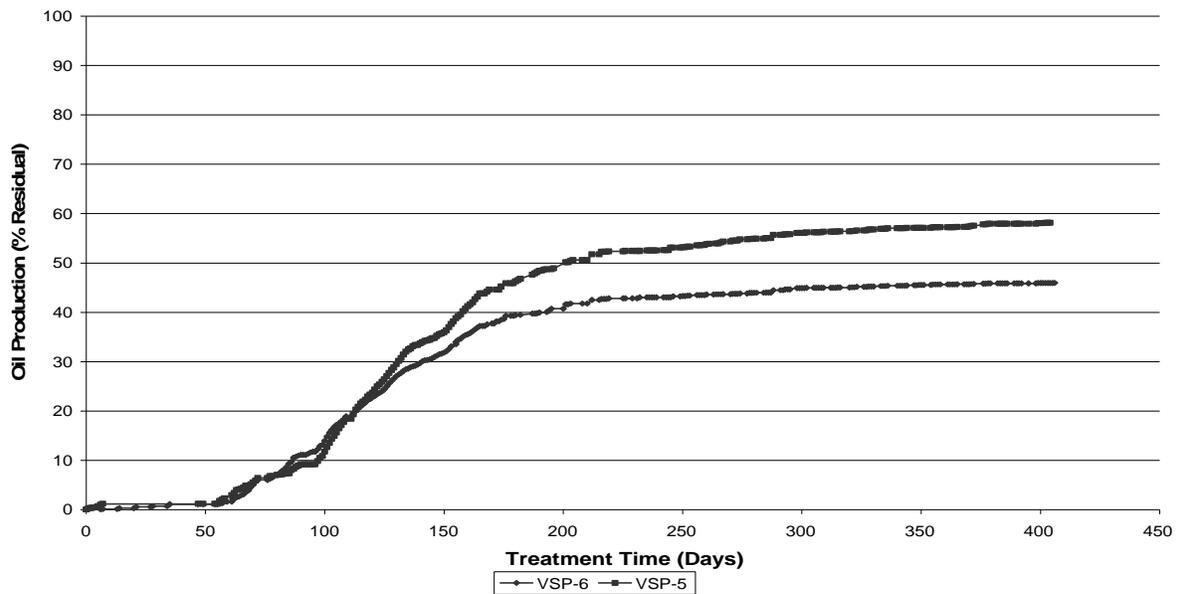


Figure 34. Comparison of VSP-5 and VSP-6.

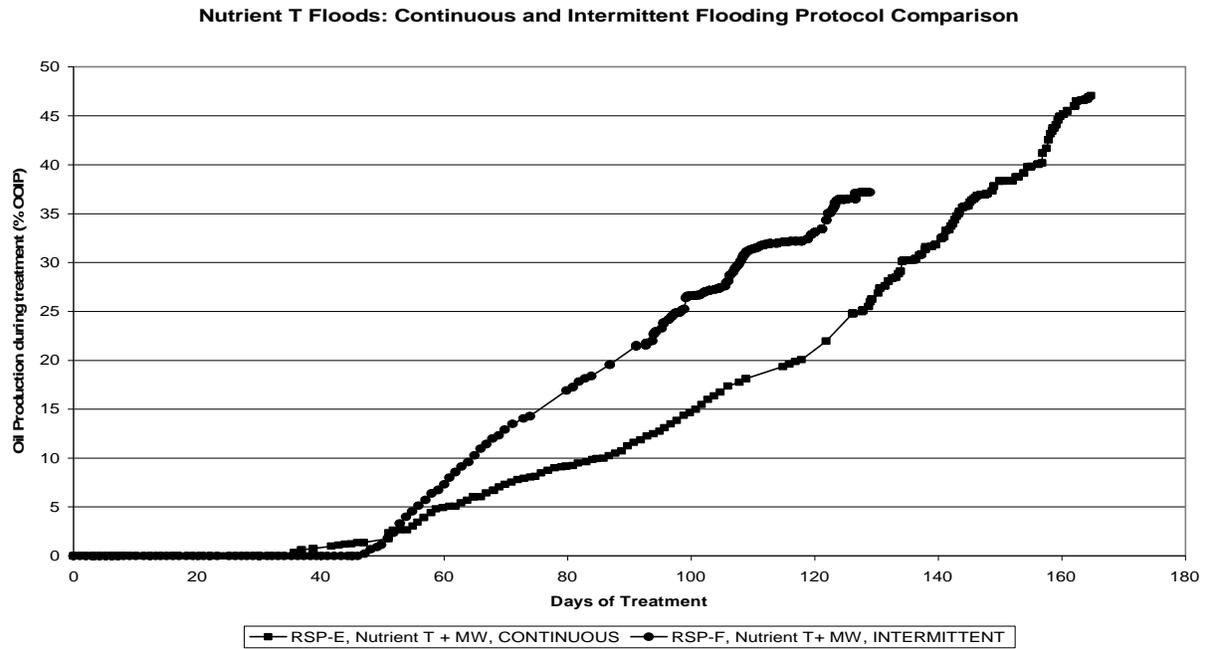


Figure 35. Comparison of Continuous and Intermittent Nutrient T Floods.

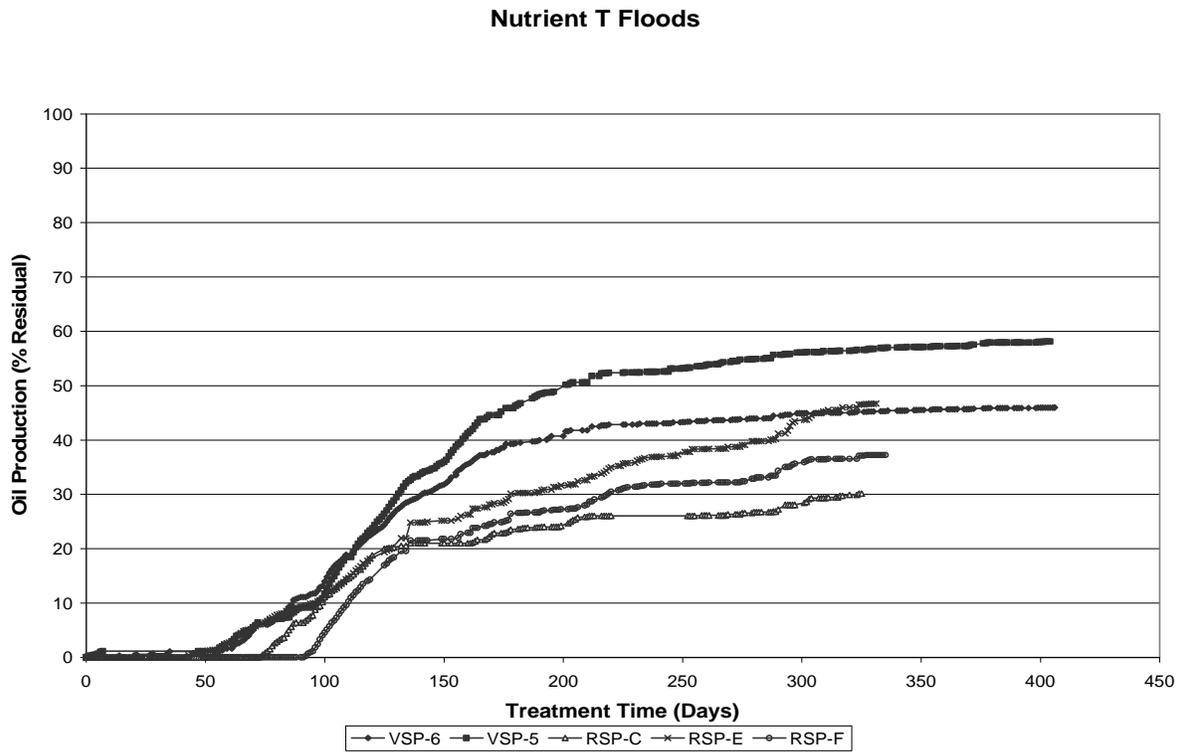


Figure 36. Comparison of Various Nutrient T Floods.

Field Evaluation of New Technology/Products

Introduction

As results were obtained from the laboratory investigations and made available to field operations through technology transfer, some of the findings were offered to interested operators who accepted the technology for application in their field studies, situations, and operations. As the laboratory results were incorporated into pilot field projects, these field operations were closely followed and monitored and the results integrated back into the laboratory investigations. The incorporation of results from such fields and participation of the operators provided additional feedback data from such projects. These pilot field evaluations were conducted in conjunction with ongoing projects whenever possible. By utilizing such ongoing projects, the requirements for collection of baseline data, flood responses, field operations, etc. was minimized. A pilot study was implemented with operator assistance. This approach allowed rapid introduction and evaluation of systems/products that have been developed by this program and provides directly comparable data. This method of field testing offers a low cost and easily approved and operated system to introduce the technology/products which have been developed in this research program.

Pilot Field Tests

Kern County, California Field Test

This project, with a major oil producer in California, was started in March 2001 in the Lost Hills Field. The Lost Hills oil field was discovered in the early 1900's (1910 to 1915). Production has grown since that time. The zone associated with this microbial enhanced recovery is the deep marine diatomaceous shale. The very high porosity varies from 45 to 70% with a very low permeability of 0.1 to 3 millidarcies. Oil saturations vary from 30 to 60% with producing API gravities from 26 to 28 driven by a solution gas drive. The reservoir thickness varies from 700 to 1700 feet with the top of the formation varying from 1500 to 2300 feet from the surface.

The field has been waterflooded for several years. The treatment test area includes three injection wells and nine production wells (map shown in Figure 37). A set of control wells of two injection wells and eight production wells was included in the trial for comparison purposes (map not shown). Treatment was started on March 20, 2001 using a proprietary blend of nitrate-based Max-Well 2000 product. This customized Maxwell formulation for the field program was used based on laboratory results of increased oil recovery and sulfide reduction and previous field trials in California and elsewhere.

The formulation of the Maxwell product was designed specifically for the targeted field water after reviewing the laboratory results. Availability of product, together with the minimum storage and equipment needs were additional incentives for its usage. The field testing of the Maxwell formulation for oil recovery would further confirm and establish the success of this new oil recovery technology. The Maxwell process relies on nutrient stimulation of the indigenous microbial population to produce oil-releasing byproducts such as nitrogen, carbon dioxide, and methane gases; surfactants; solvents; and alcohols. The Maxwell nutrient was injected

continuously with the waterflood, which has a temperature of 100° F. Maxwell treatment injections were stopped on November 30, 2001, for a treatment interval of 8.5 months. Final results are shown in Figures 38-41. Increased oil production returned to baseline prediction by January 31, 2002, demonstrating the usual beneficial lag effect of treatments.

Oil production in the treated wells increased by 21% over the predicted decline curve production. Oil production in the control wells increased by 3% over the predicted decline curve production. All oil production data was provided by the operator. On a commercial basis, the resulting oil increase in the treated wells would cost \$1.56 per incremental barrel gained.

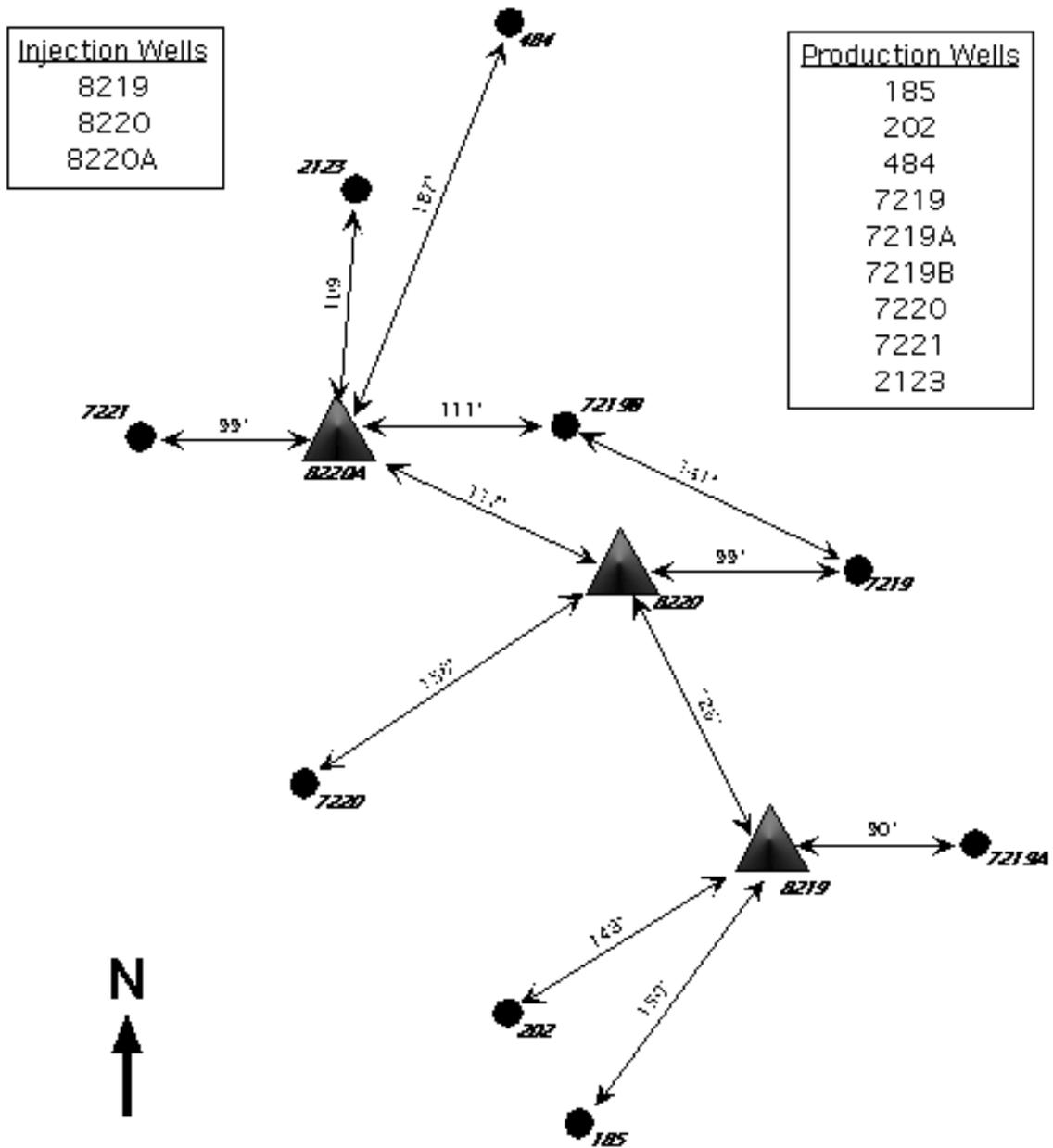


Figure 37. Lost Hills field test area.

Lost Hills Water Flood: Increased Production Cost of \$1.56 per Incremental Barrel

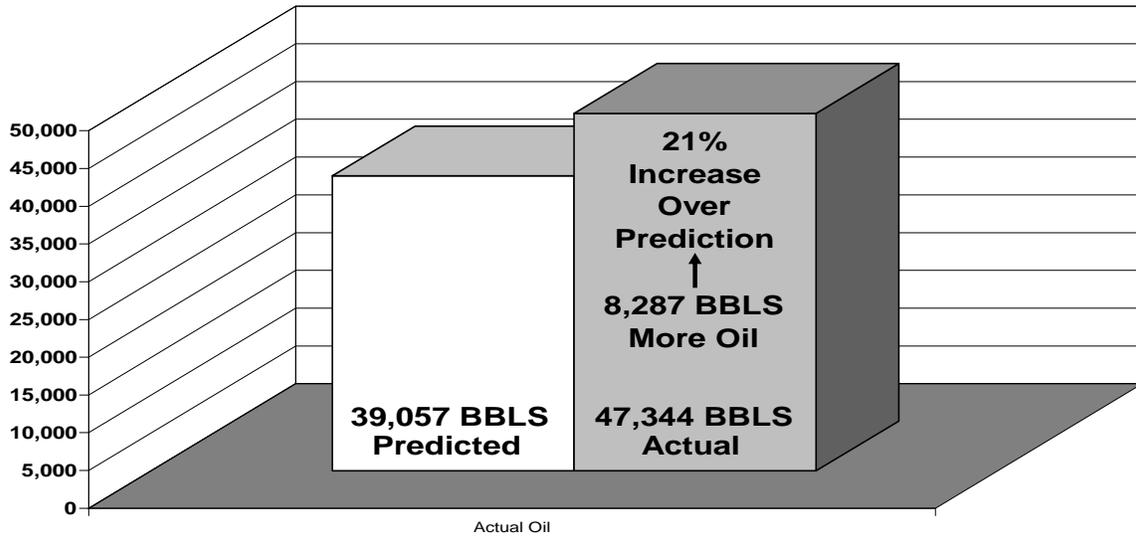


Figure 38. Combined production for nine Maxwell-treated wells, Mar. 20, 2001 – Jan. 31, 2002.

Lost Hills Waterflood: Nine Test Wells Production During the Maxwell MEOR Trial

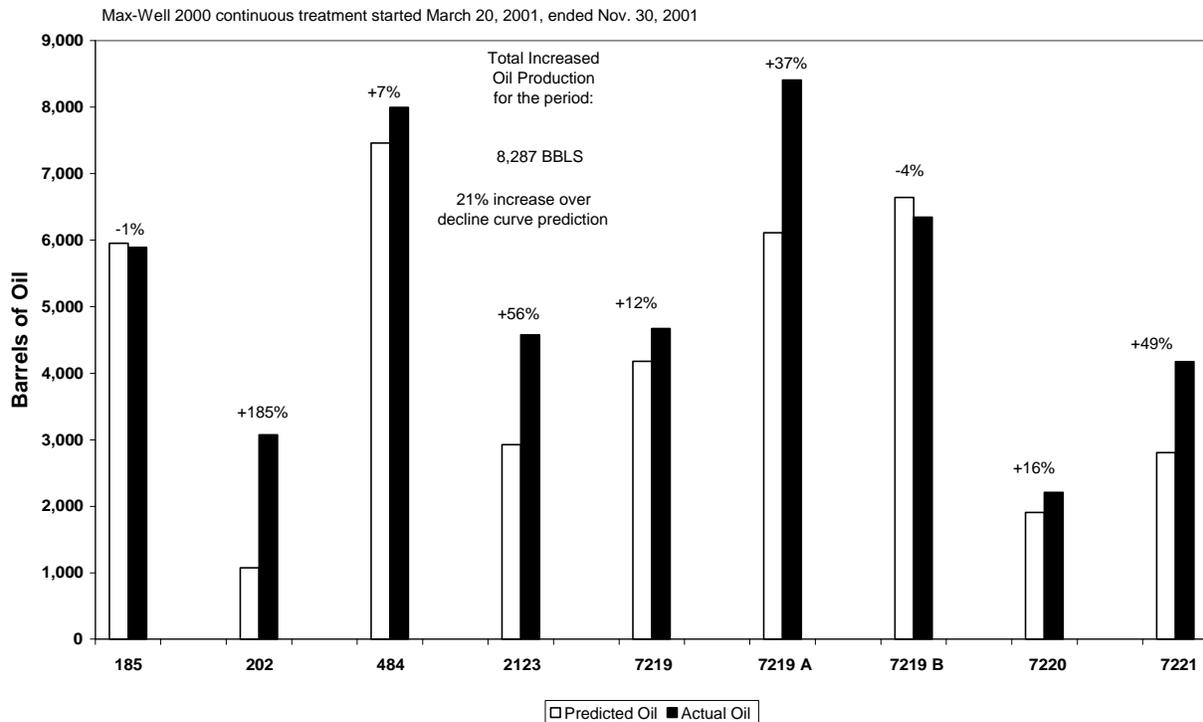


Figure 39. Maxwell-treated well production Mar. 20, 2001 – Jan. 31, 2002.

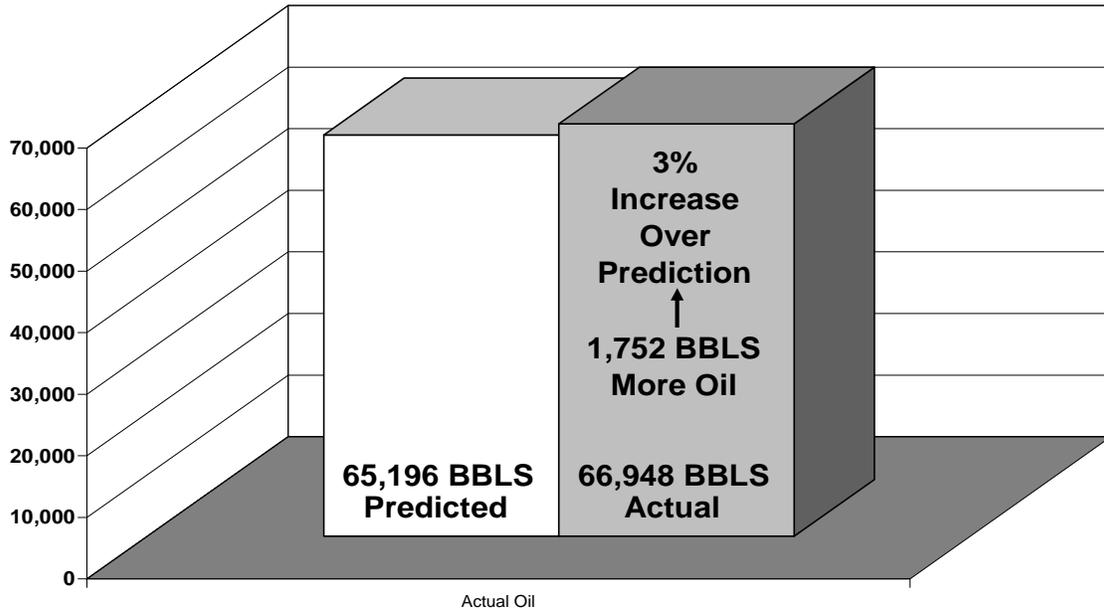


Figure 40. Combined production for eight control wells, Mar. 20, 2001 – Jan. 31, 2002.

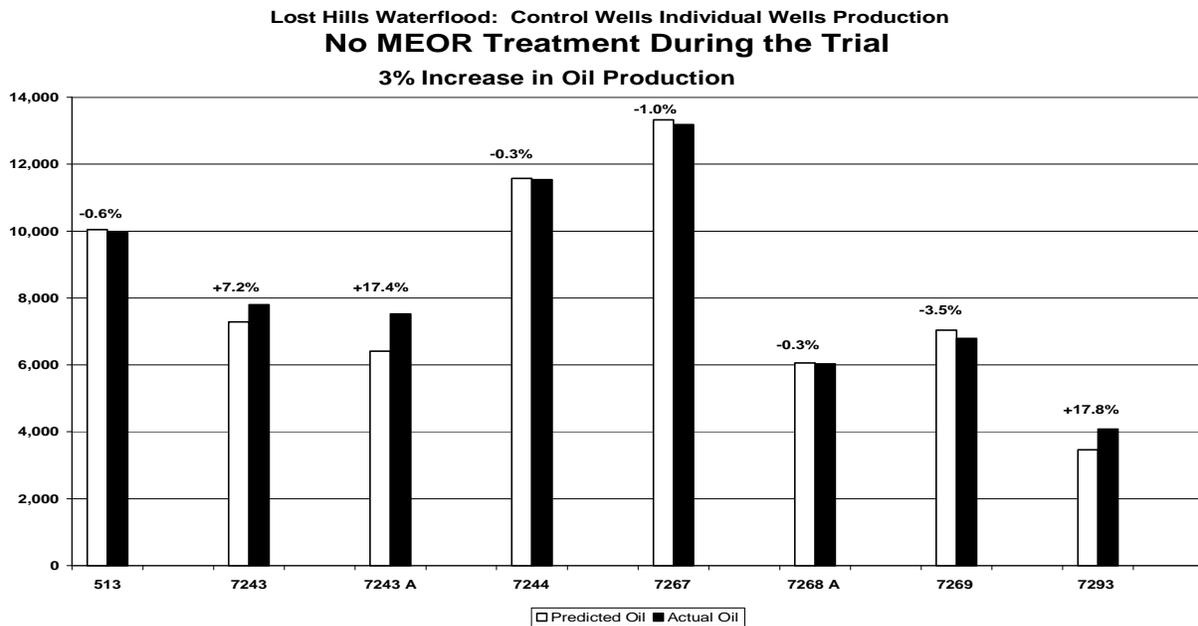


Figure 41. Control well production Mar. 20, 2001 – Sept Jan. 31, 2002.

Belridge Field Test

A second field test was conducted in the Kern County Belridge field. Most of the production in the Belridge field is from the Tulare zone located at depths from 450 to 950 ft. The field is waterflooded and sour. The test consisted of treating the annulus of production wells for the purpose of H₂S control in sour waterflooded wells. Production in this field dates back 90 years with most wells completed in the 1940-60's. Well spacing is very close. The objective was to use a different Max-Well nutrient product to reduce H₂S and improve the water/oil ratio (WOR) in two ways: suppress growth of sulfate reducing bacteria while increasing the population of denitrifying bacteria and reduce iron sulfide in the near-wellbore area to free up production pathways, thereby increasing production.

Treatments were started September 14, 2001, with monthly batch treatments.

The Maxwell treatment in this test consisted of monthly batch treatment of 20 wells with 10 wells being treated only twice and 10 wells being treated three times during the four month test period. Ten additional wells were designated as untreated control wells. The treatments were at minimum levels to examine the effects of low concentrations of Maxwell at a monthly treatment interval. Only trend values could be examined and the small number of available field production data made even these trend values difficult to evaluate.

The results from the treated wells showed trends that indicated an observed increase of sulfide in several wells could be caused by the treatment breaking up the iron sulfide and releasing it gradually. This would be a desired effect rather than a very quick release by a direct chemical reaction, which could cause the iron sulfide to become a potential plugging agent in downstream equipment. In other cases the sulfide concentration was notably decreased following treatment, indicating sulfide was being brought under control in these wells.

In the majority of wells there was no significant change in oil production that could be attributed to the treatment, nor was there expected to be a large oil increase at such low concentrations and with intermittent treatment. These Belridge data are presented to illustrate the difficulties that are encountered in monitoring the effects of any test treatment under field operating conditions in which the collection of data is not intensively controlled and monitored, and teach that complete and accurate data collection must be an integral part of any field program; that such a program should be conducted over a much longer period of time; and that it should include variations of treatment protocols and treatment product amounts. Results are shown in Figures 42-71. The data shown are the daily averages for each month.

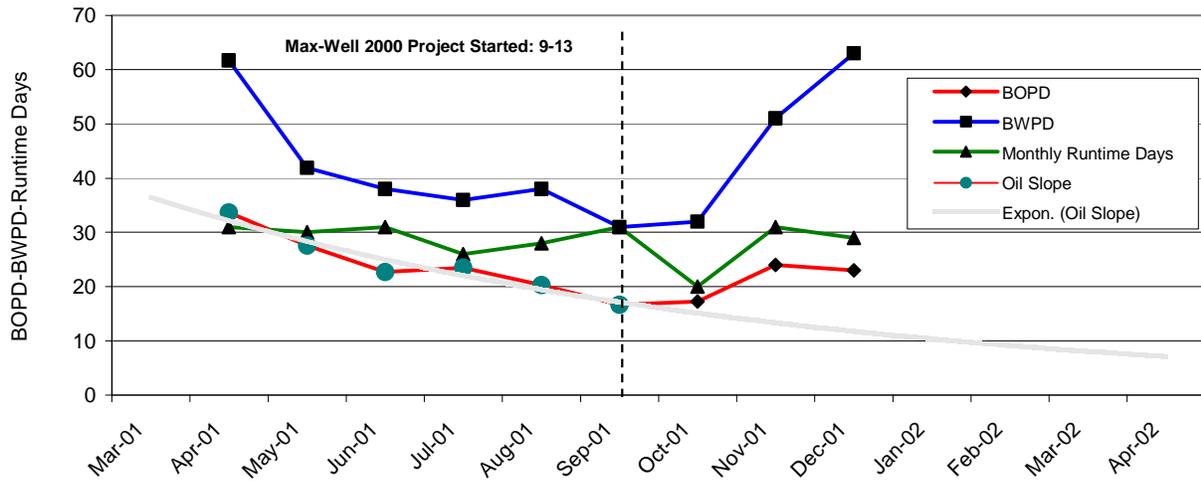


Figure 42. Belridge control well 7287A.

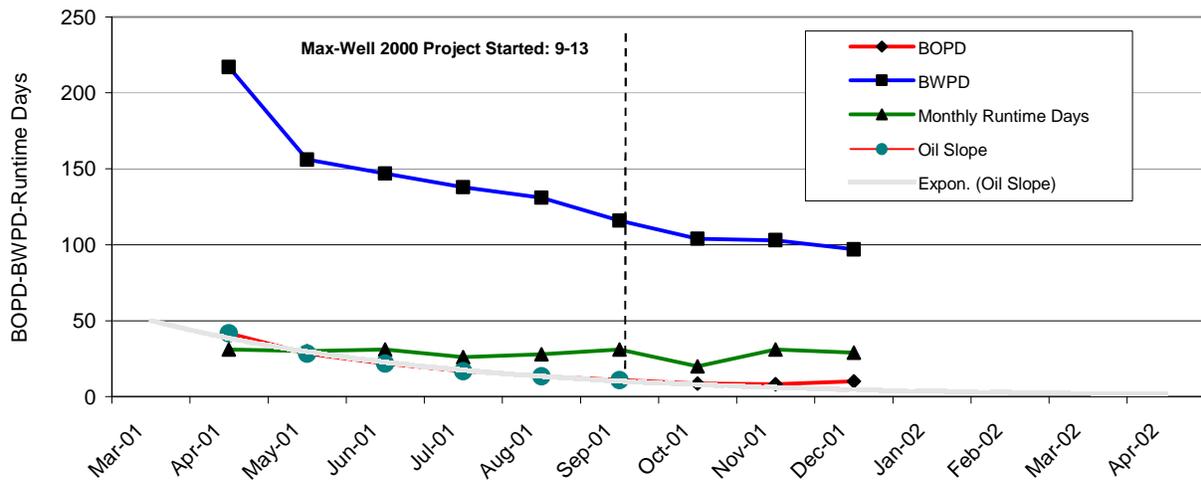


Figure 43. Belridge control well 7307A.

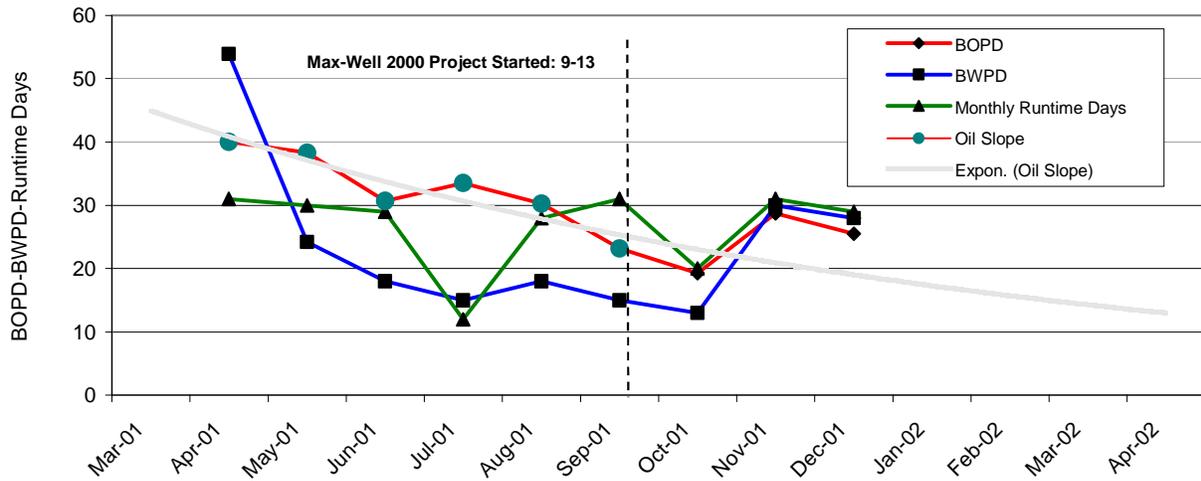


Figure 44. Belridge control well 7313.

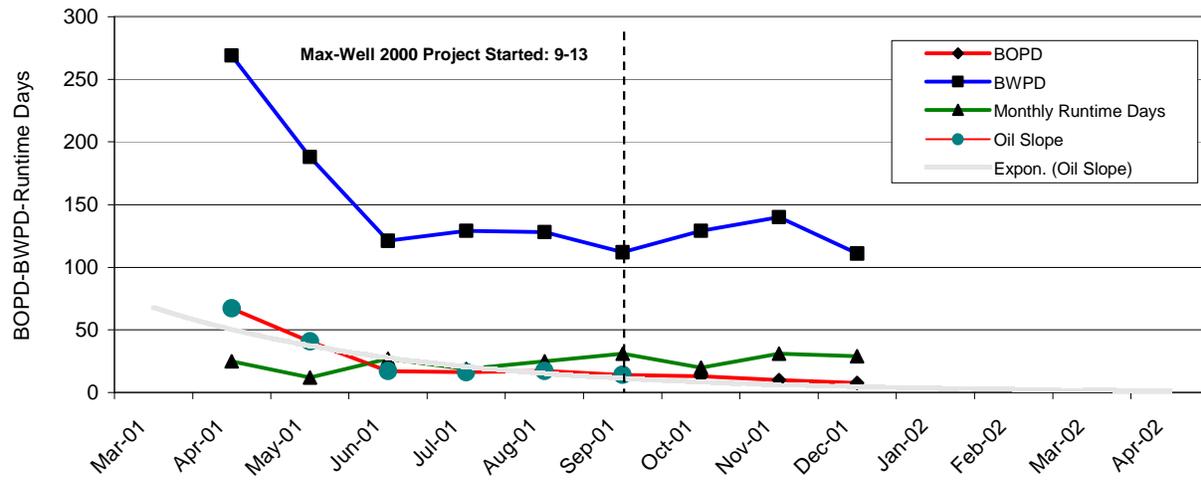


Figure 45. Belridge control well 7329.

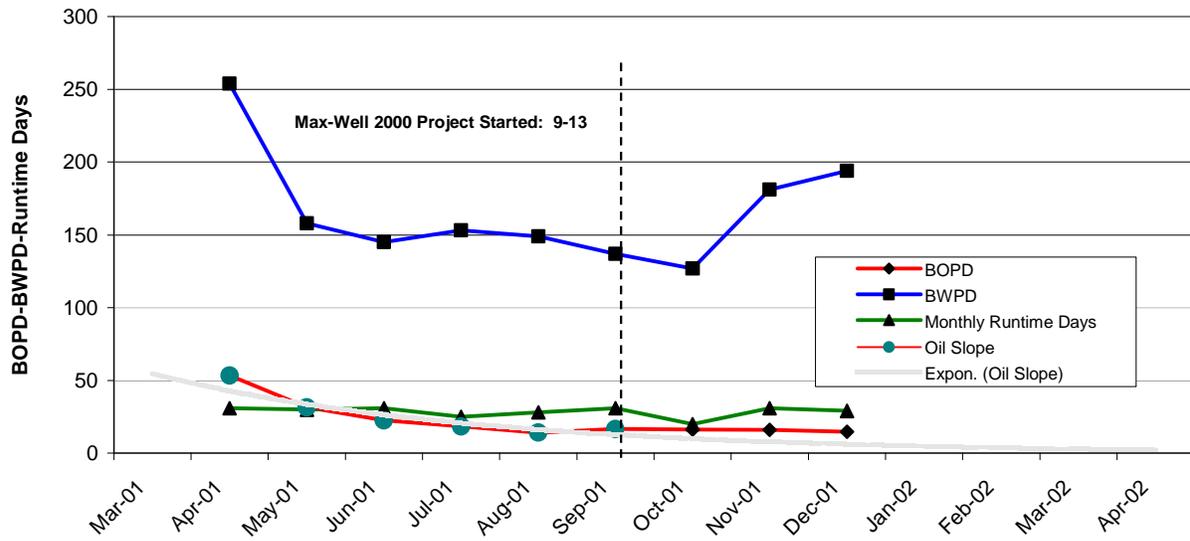


Figure 46. Belridge control well 7355A.

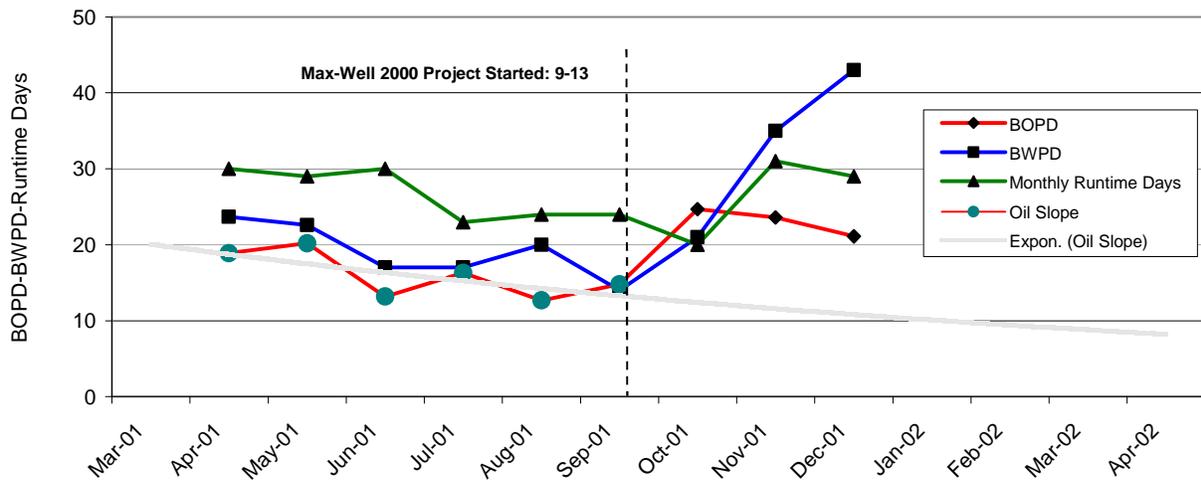


Figure 47. Belridge control well 7361B

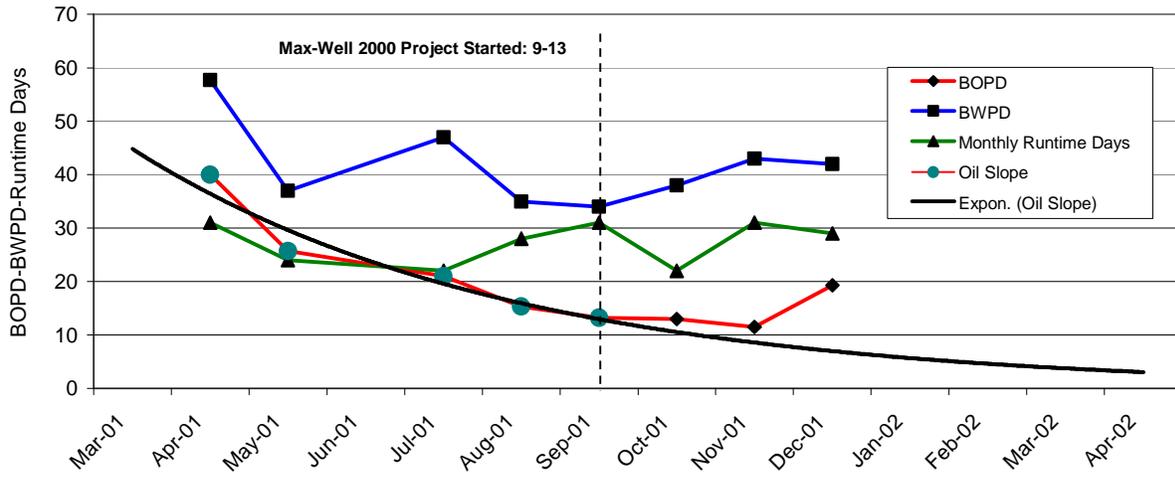


Figure 48. Belridge control well 7383.

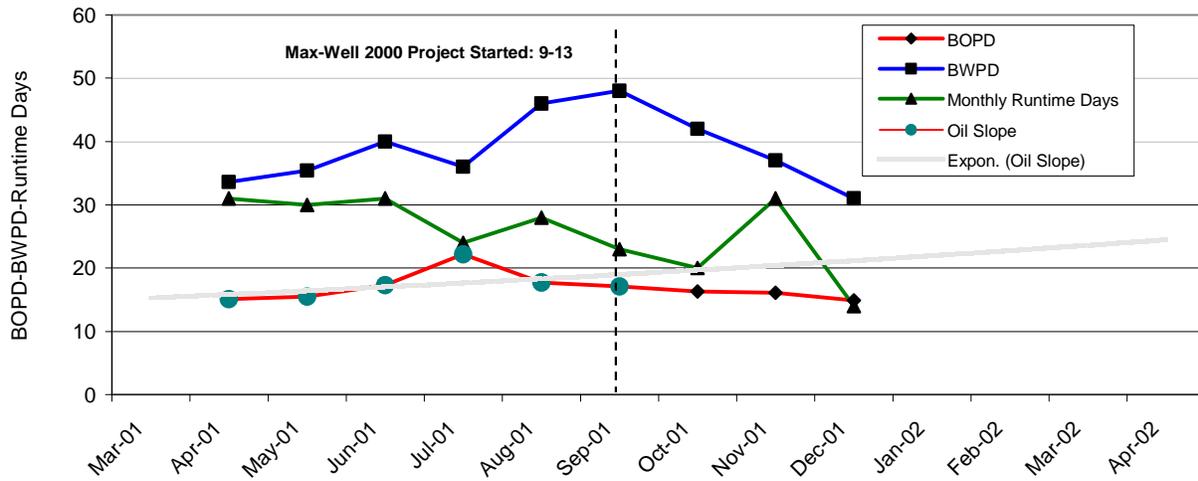


Figure 49. Belridge control well 7406.

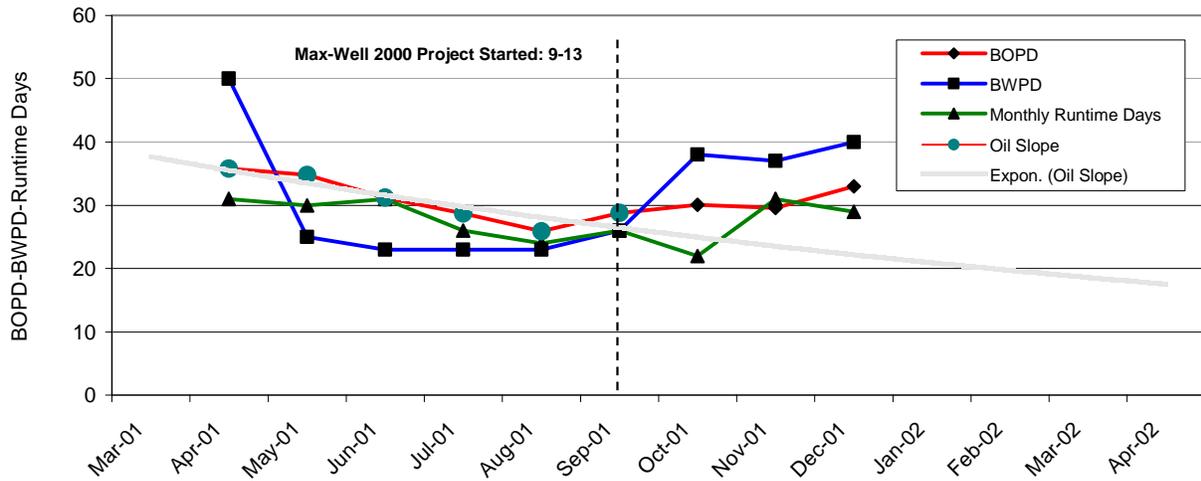


Figure 50. Belridge control well 7409.

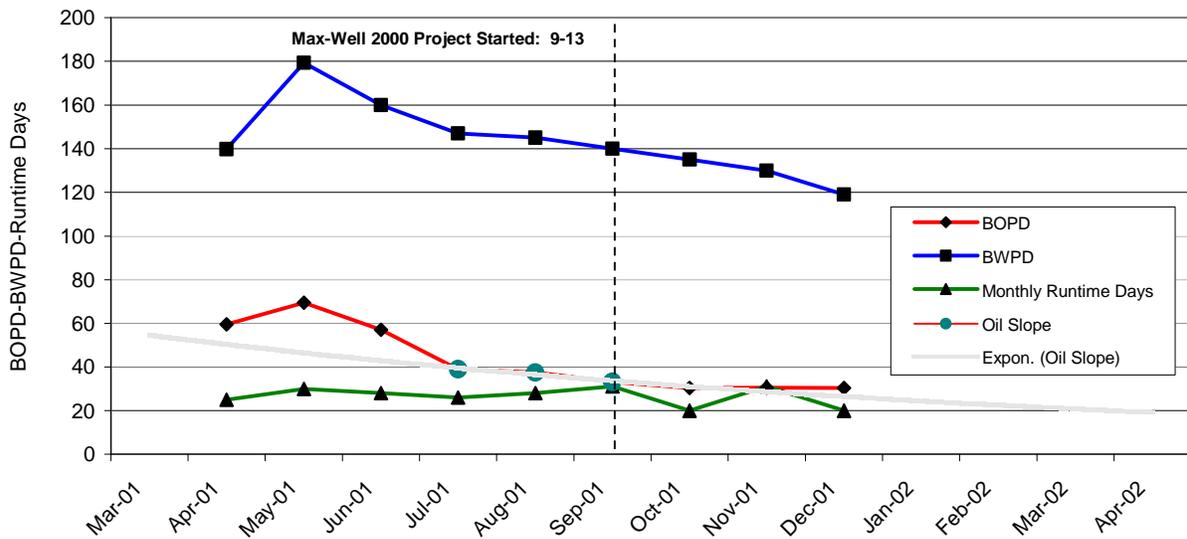


Figure 51. Belridge control well 7284A.

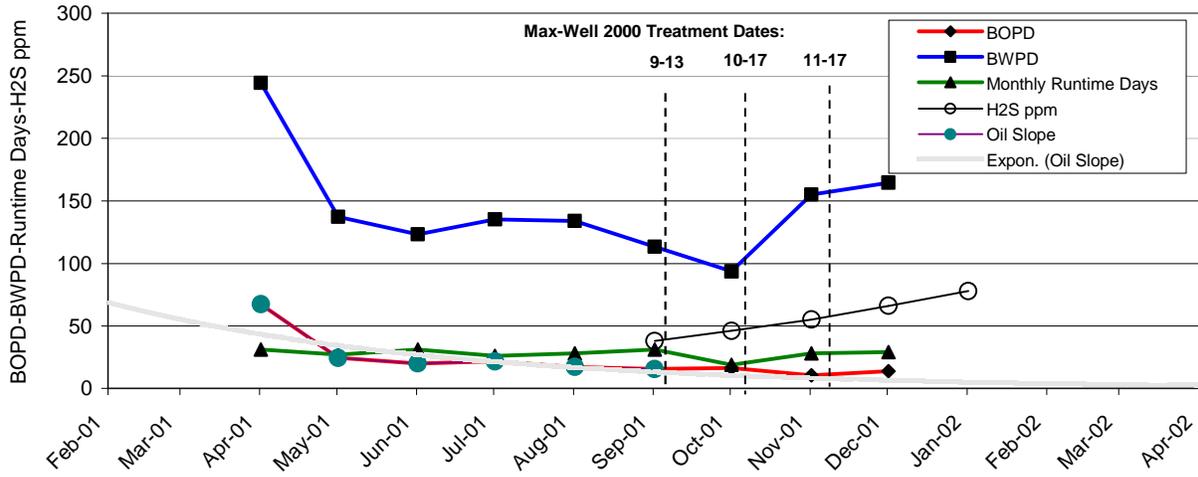


Figure 52. Belridge test well 7283A.

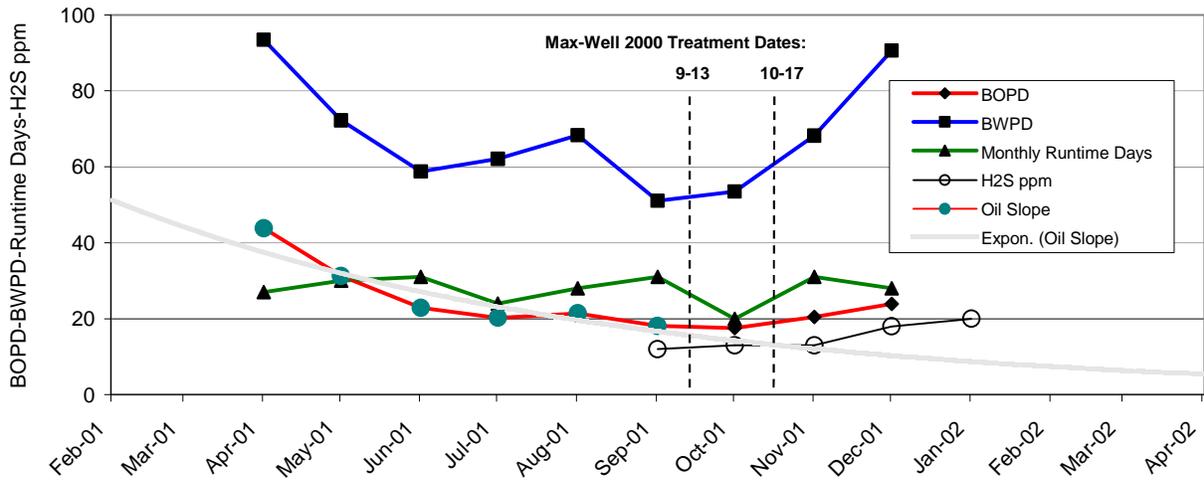


Figure 53. Belridge test well 7285A.

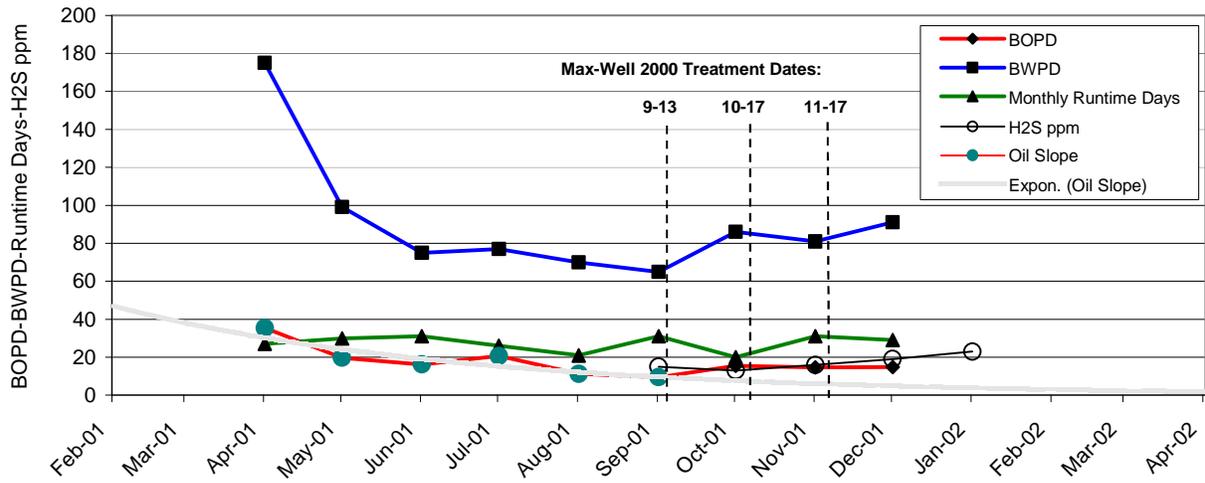


Figure 54. Belridge test well 7306A.

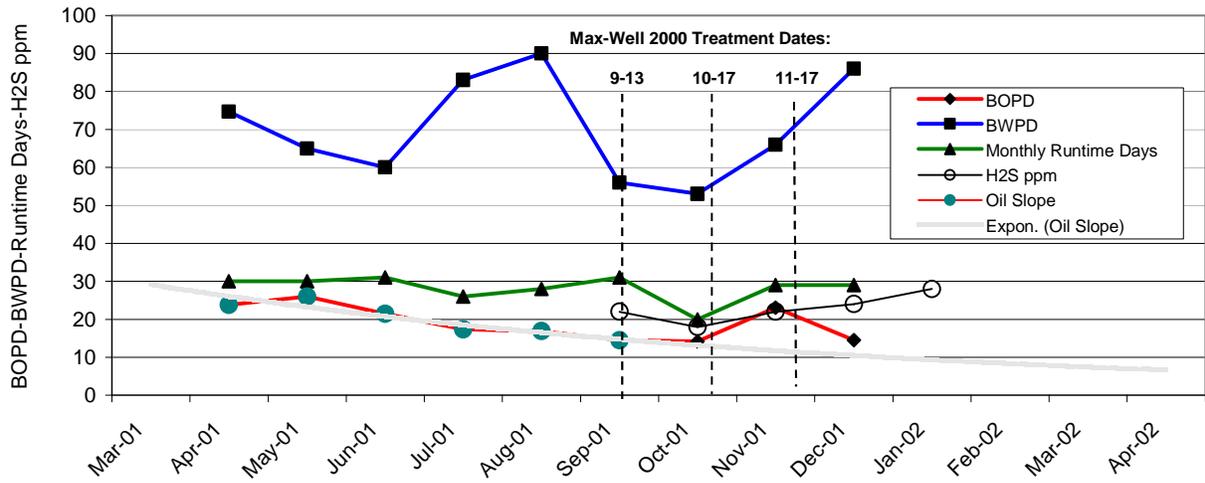


Figure 55. Belridge test well 7309A.

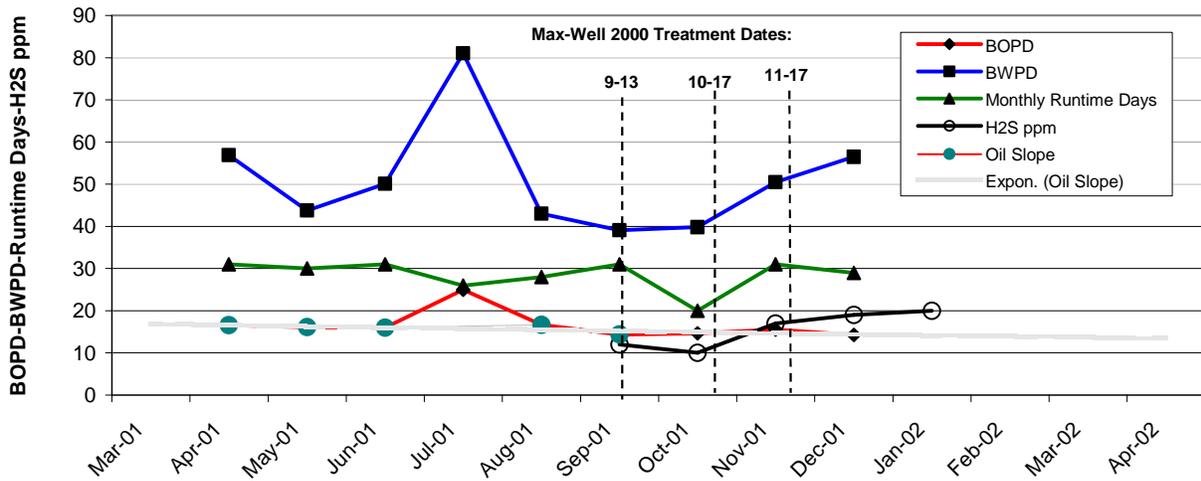


Figure 56. Belridge test well 7310A.

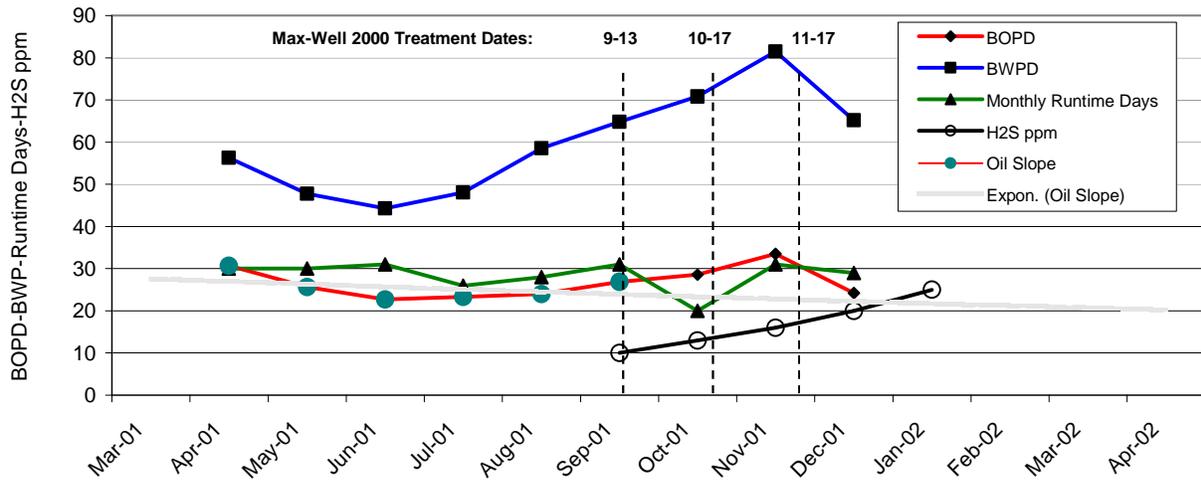


Figure 57. Belridge test well 7310B.

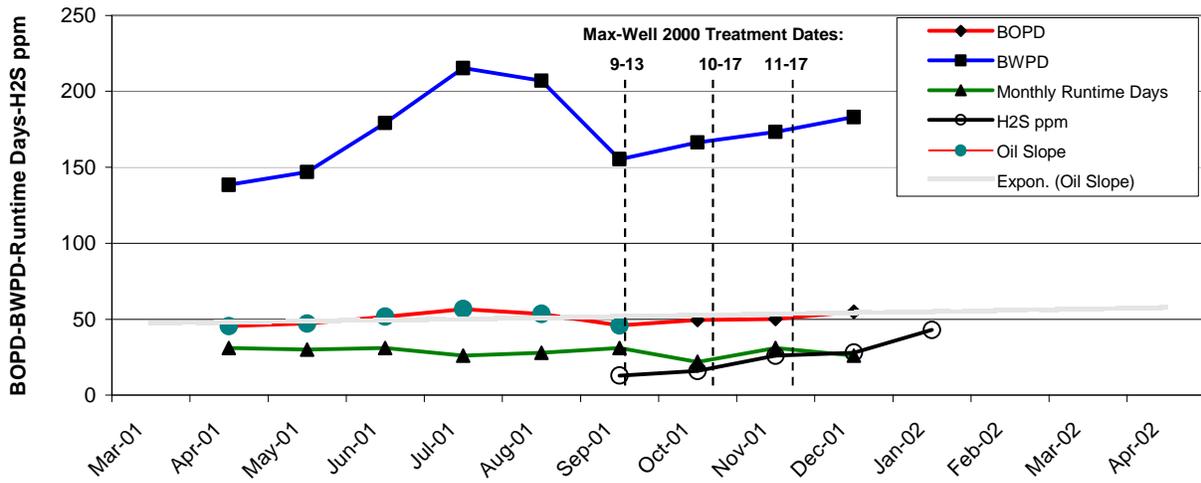


Figure 58. Belridge test well 7311A.

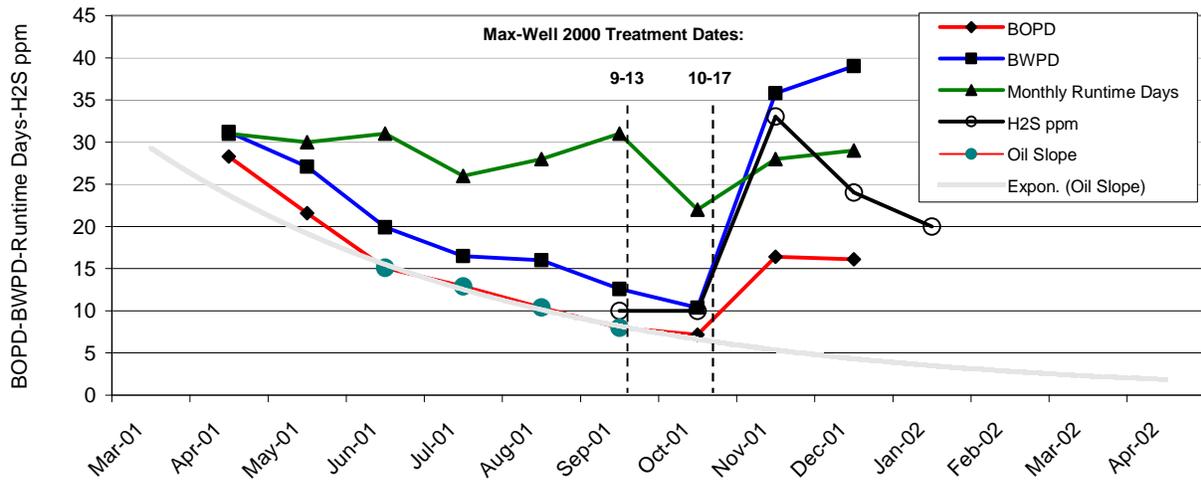


Figure 59. Belridge test well 7312.

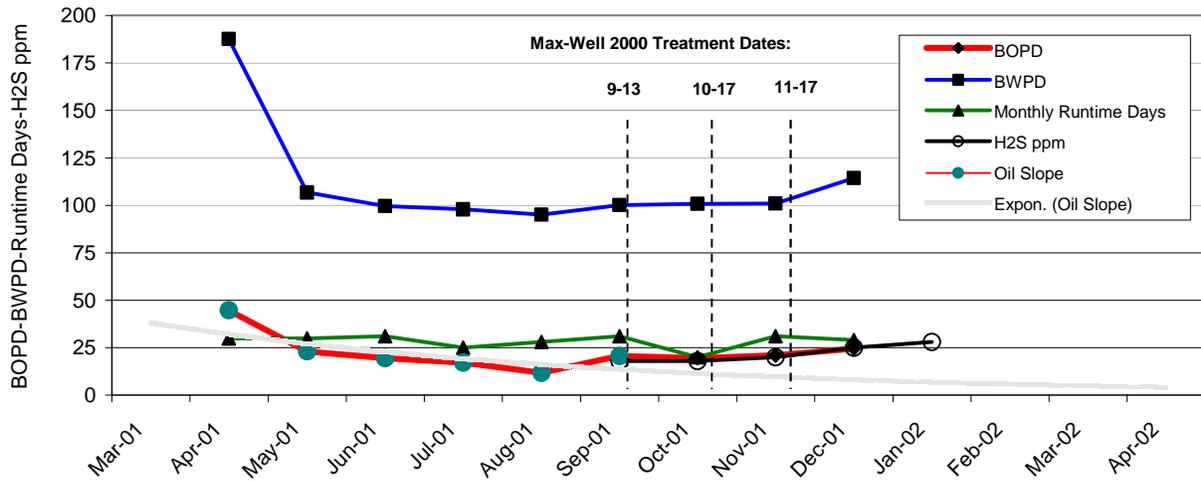


Figure 60. Belridge test well 7332A.

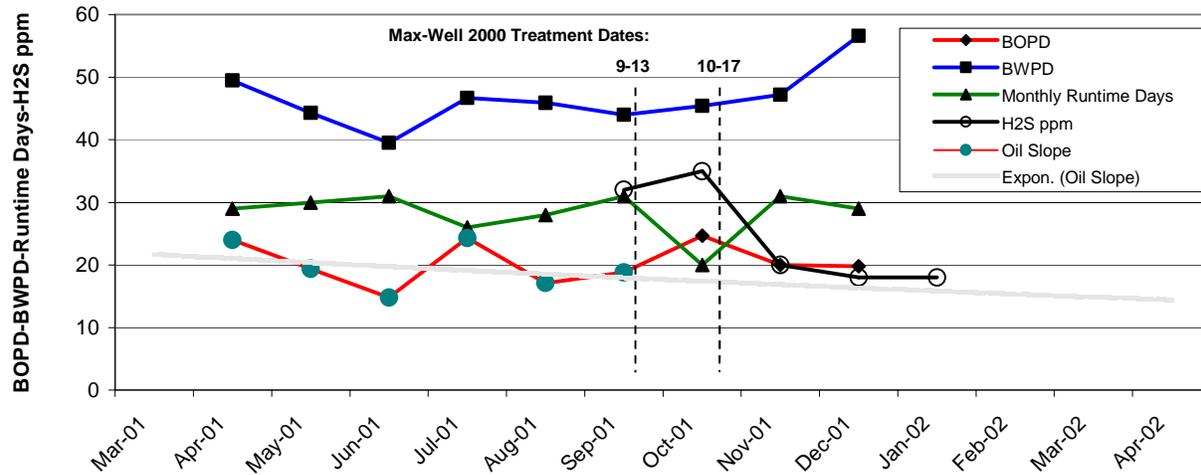


Figure 61. Belridge test well 7333.

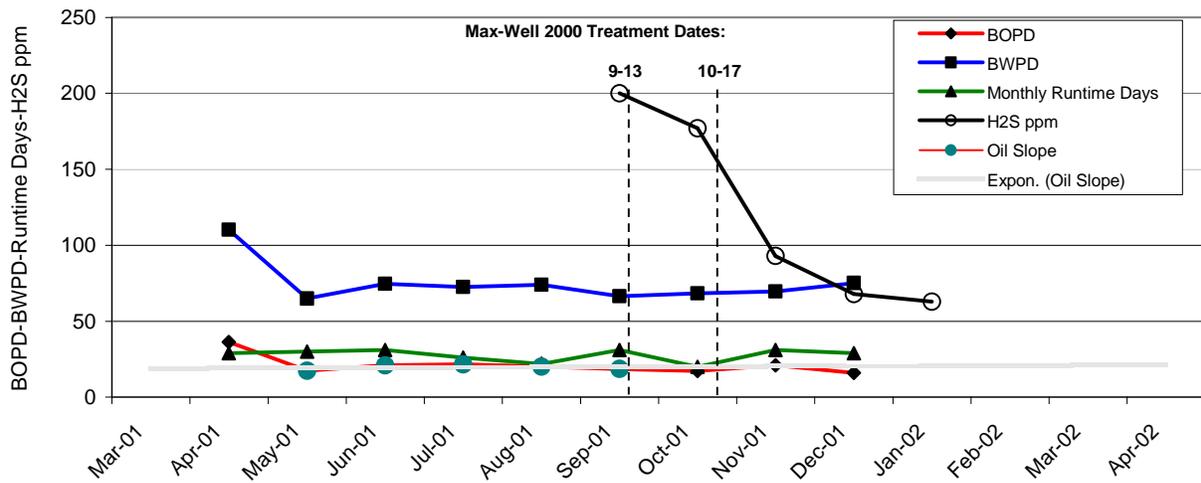


Figure 62. Belridge test well 7333B.

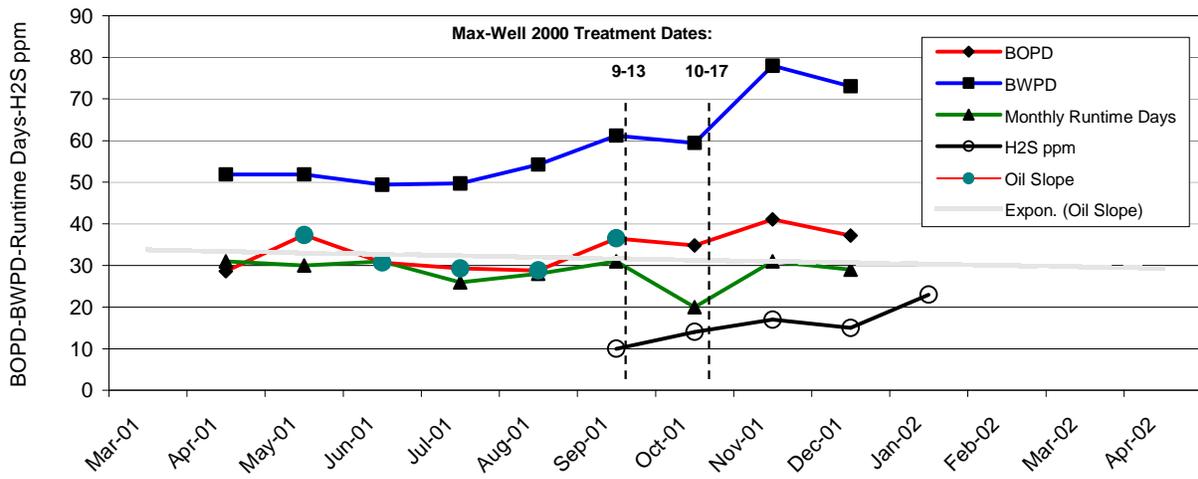


Figure 63. Belridge test well 7334A.

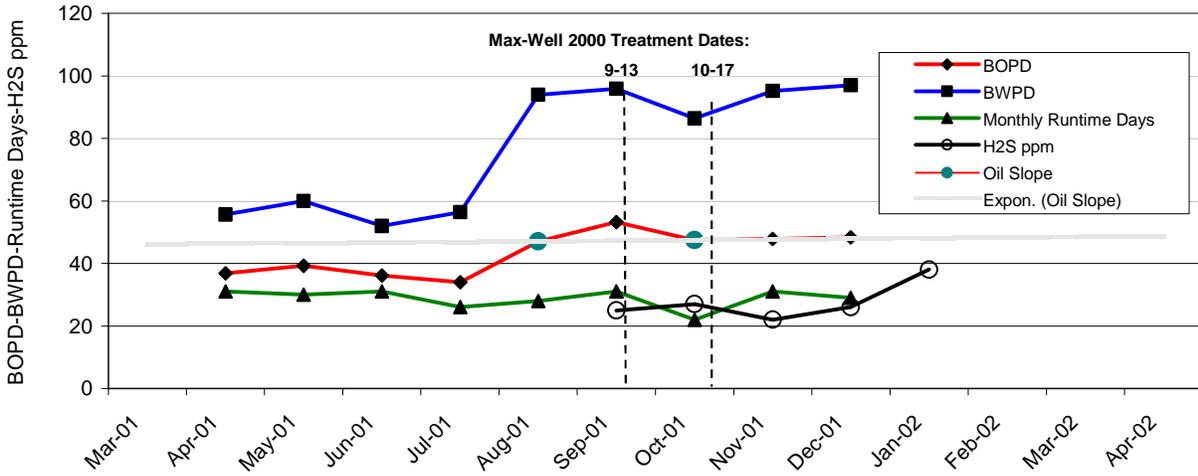


Figure 64. Belridge test well 7335.

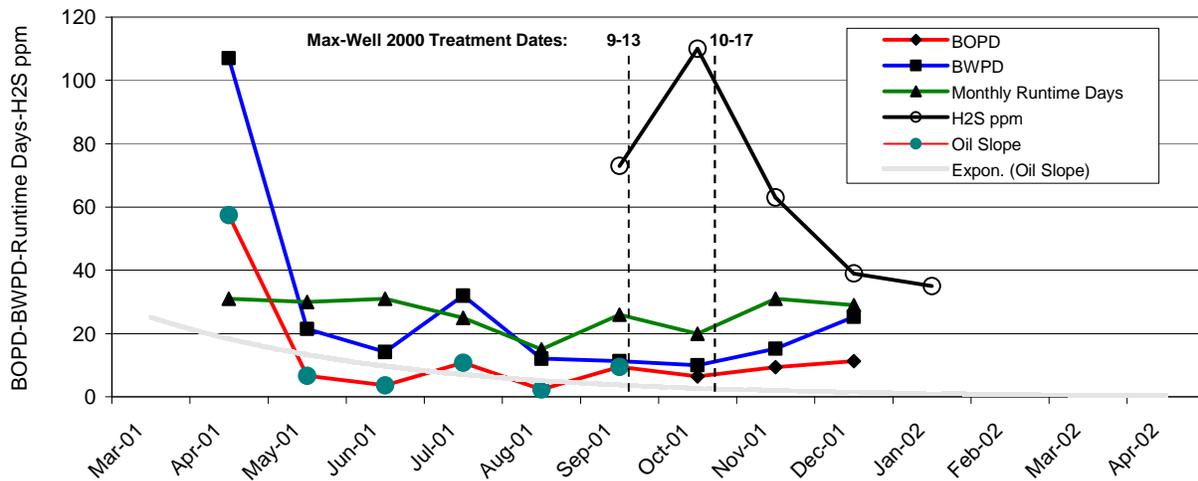


Figure 65. Belridge test well 7337.

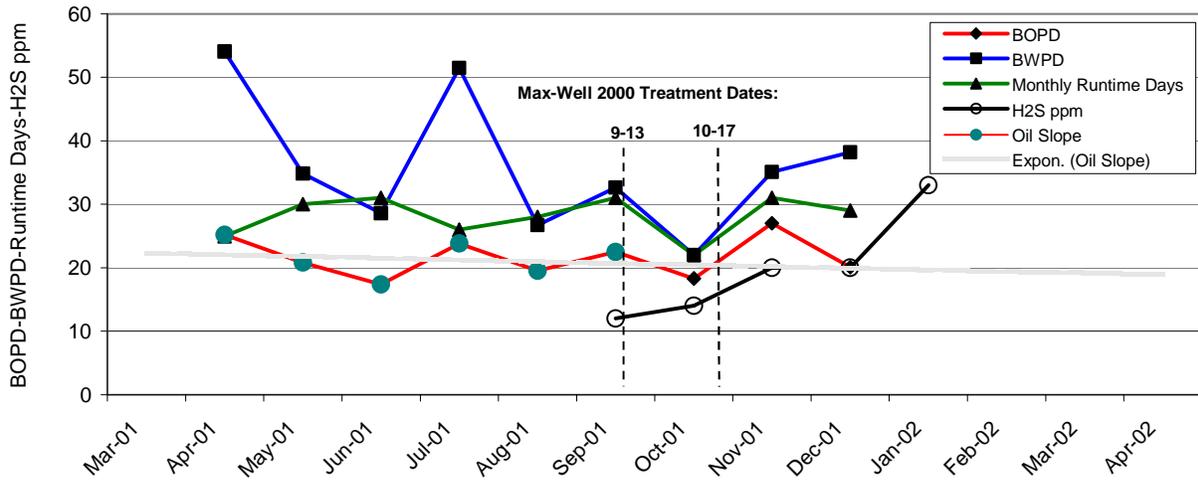


Figure 66. Belridge test well 7359A.

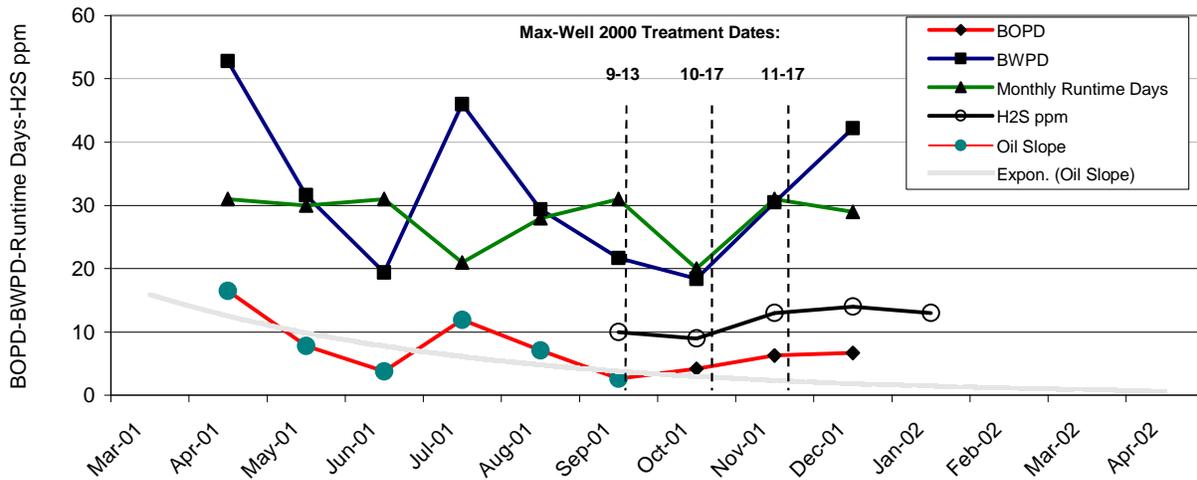


Figure 67. Belridge test well 7361A.

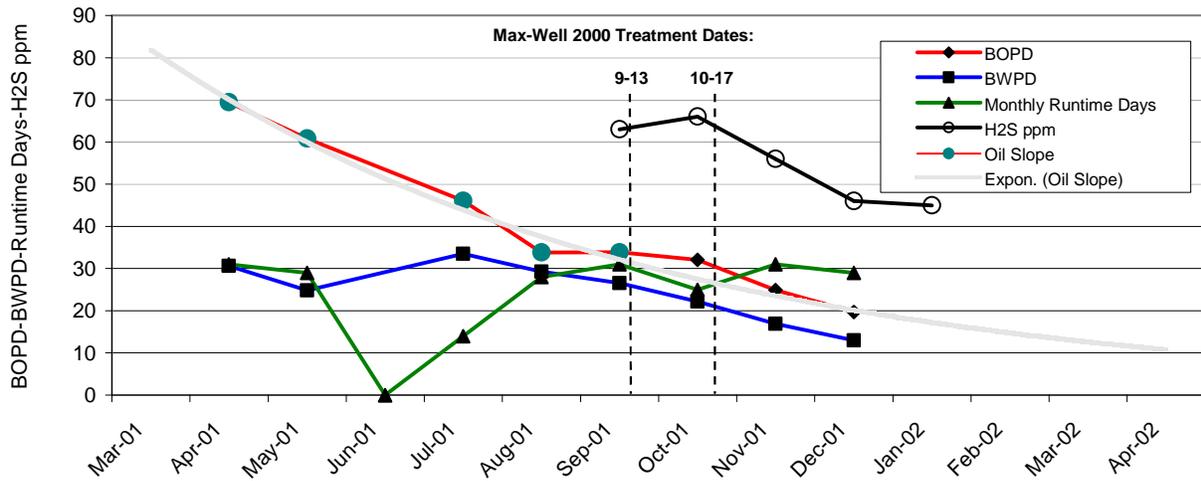


Figure 68. Belridge test well 7404.

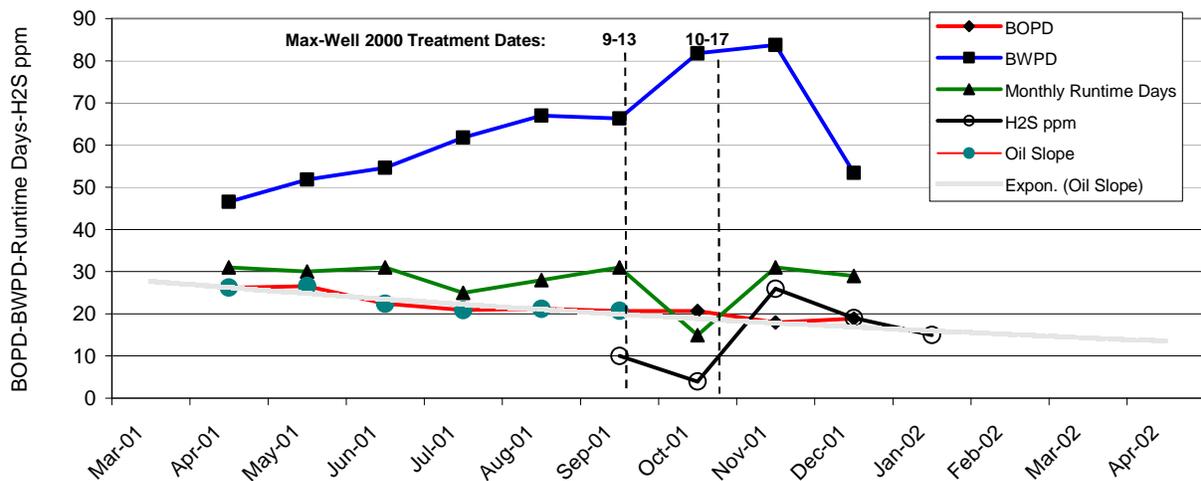


Figure 69. Belridge test well 7407.

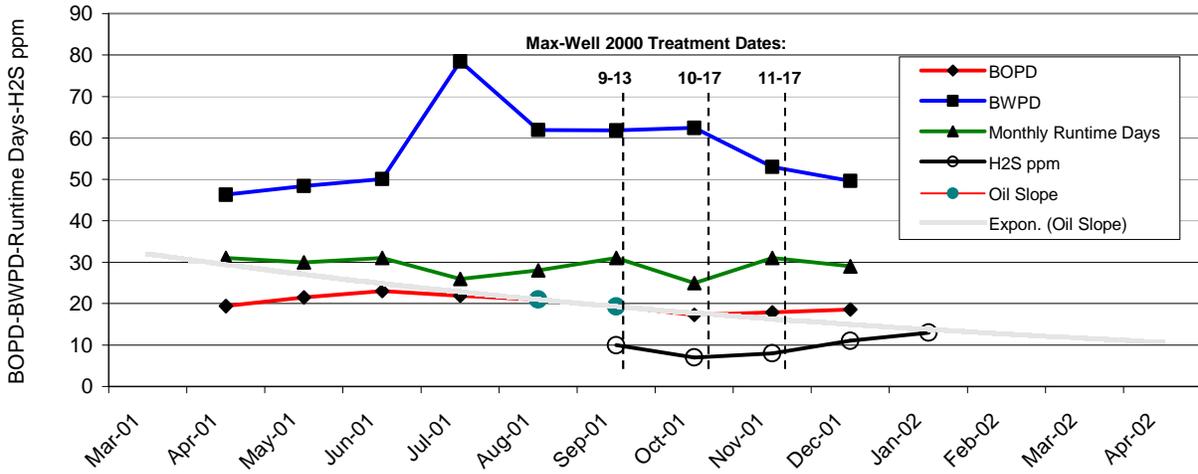


Figure 70. Belridge test well 8383.

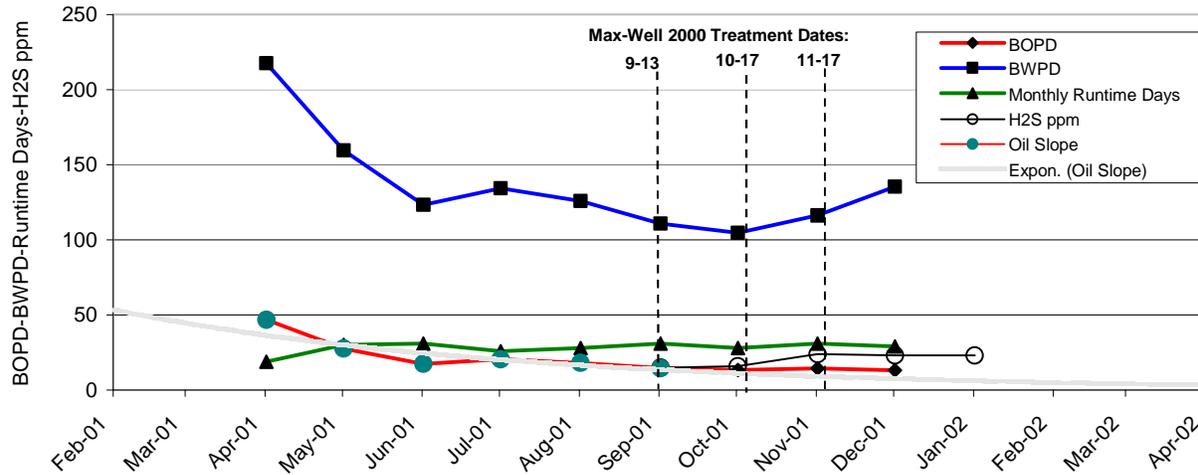


Figure 71. Belridge test well 7283

Weyburn Field Test

The results from the continuing laboratory studies and the California field studies encouraged the initiation of an expanded field test in a Canadian reservoir. This project was in the Weyburn Field area. Weyburn is in southeast Saskatchewan and the production is Mississippian coming from dolomitic limestone. The waterflood injection wells were treated with Maxwell 2000 amendments. Of great importance, the production records on the Weyburn field were available for 2 years preceding the treatment period and allowed an extended baseline production data decline curve to be established. These data established a firm decline curve against which the effects of the treatment could be matched. The Maxwell treatment was for a period of seven months followed by a post-treatment data collection period. The oil production data were collected by the operating company field personnel from 11 waterflooded production wells that were measured at daily intervals (Figures 73-83); and the data for all wells was composited (Figure 72).

The Maxwell treatment was added continually at a low concentration to the injection water without alterations to the normal field operations. As would be expected, several wells responded rapidly to the treatment while other wells showed a delayed response; some wells did not respond during the treatment period. It is expected that the non-responsive wells would have a positive response with a longer treatment period. As significant as the increase in production is which occurred during the treatment period, is the data which show a decline in oil production after stopping the Maxwell treatment. It should be noted that the lag in the decline in oil production following treatment indicates that the effects of the treatment persisted in the reservoir during the lag period. This again is suggestive of microbial growth and response to the Maxwell treatment.

In observing these positive effects on oil production, it is assumed that the interval between treatment initiation and stopping the treatment and the oil production response is due to transit time between injection well and producing wells, channeling, heterogeneity of the reservoir, and other possible factors in the reservoir matrix. Since there were reportedly no changes in flooding rates or volumes or equipment changes, and the increased production was gradually increasing with the time of treatment, it is reasonable to assume the observed effects were due to microbial response to the treatment in the reservoir. The Maxwell nutrient employed had an effect that would not otherwise be expected by the field personnel. It is not known if a greater oil production increase could have been observed if the concentration of Maxwell had been increased, although there is a direct correlation between microbial population size and the amount of biochemicals and gases produced. Thus, more nutrient produces greater microbial growth, which produces more oil-releasing bioproducts, which in turn should produce more oil.

Although individual wells showed a variety of production responses, as expected, the composite production data from the 11 monitored wells showed a significant increase in oil production from the 31,950 bbl oil that was predicted by the operator to 39,668 bbl that was produced in the 12 month test period. This 24% increase in oil production can be attributed to microbial response to the Maxwell treatment technology.

A review of the two waterflooding field tests conducted in conjunction with the laboratory sandpack data show that the results yielded consistent comparative data and support the conclusion that the field oil recoveries were the result of targeted microbial growth derived from Maxwell treatments. Furthermore, the data show that the oil increases observed in the field were greater than those observed in the sandpack studies. This is not unexpected since the sandpacks were flooded to residual while the fields still had oil potential and would be more heterogeneous than the sandpacks. Thus, the fields would offer a greater potential for a favorable response to microbial actions and agents than laboratory models and strongly suggest that field tests are a preferred system to measure the effectiveness of microbial oil recovery mechanisms.

This increased observed oil recovery in the field occurred at low concentrations of the Maxwell so the effects were magnified and persisted longer than would have been predicted from the laboratory results. Increase in production observed in field tests over that which is measured in laboratory tests has been reported but has been viewed as being caused by other uncontrolled factors and so has been discounted by the industry. It is believed the reported very favorable oil recovery in the Maxwell-assisted waterflood field tests is real and that oil recoveries in the field should exceed any laboratory recovery values. This emphasizes the need to conduct larger scale field tests which will further prove the technology.

It should also be noted that no corrosion, plugging of wells, or other problems were reported or observed during the field tests. As a result of oil increases reported from these field tests, the involved operators are considering expanding the Maxwell treatment for field-wide treatments. The results were presented to other operators as part of the technical transfer program and have resulted in other field applications of the Maxwell treatment.

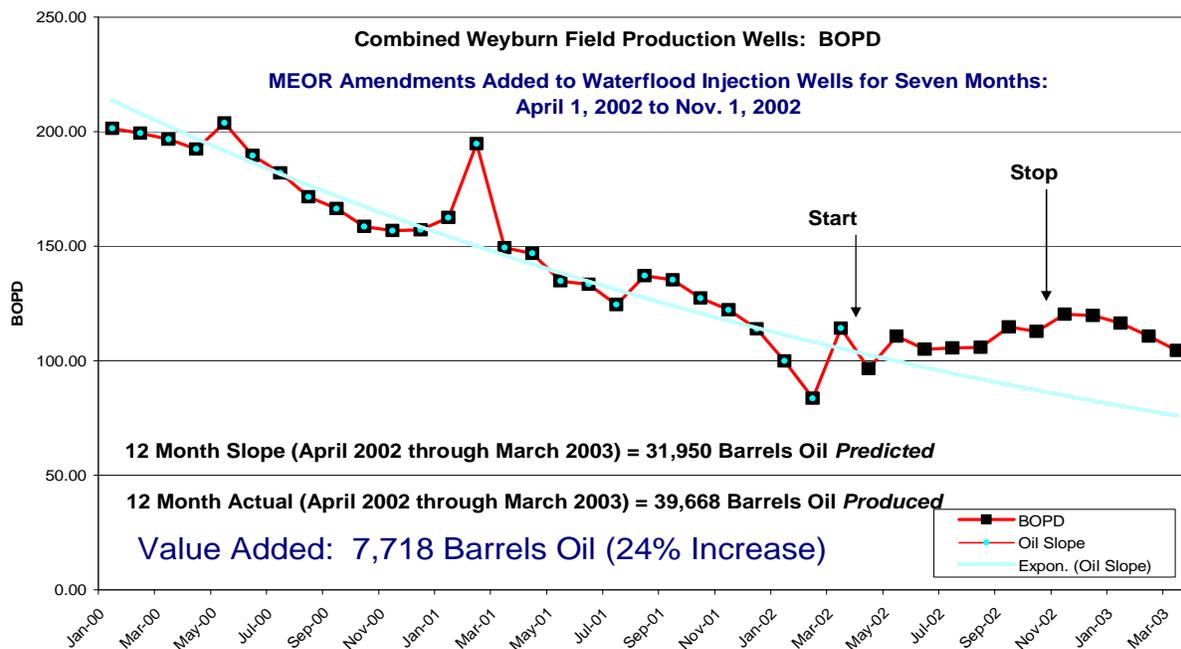


Figure 72. All Weyburn Production Wells

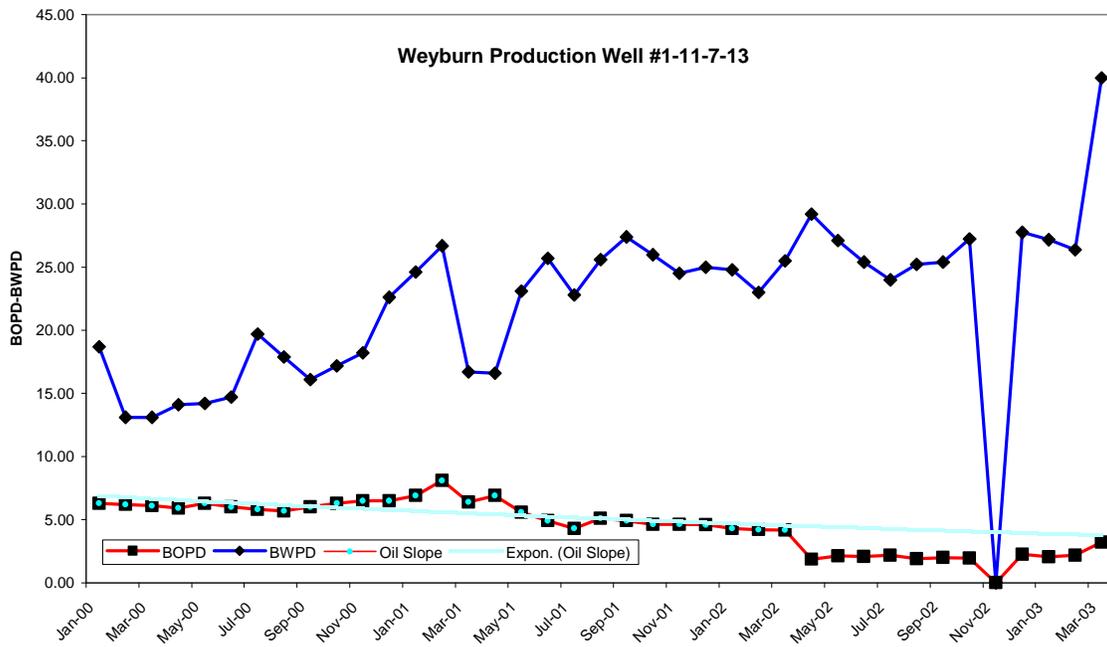


Figure 73. Weyburn 1-11-7-13.

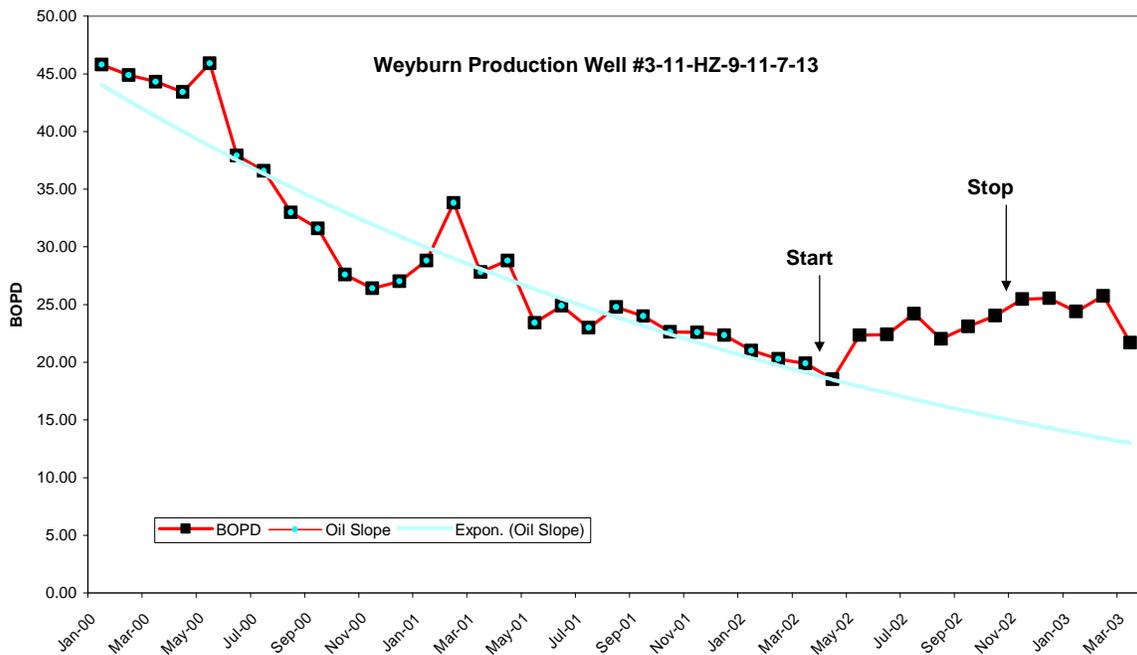


Figure 74. Weyburn 3-11-HZ-9-11-7-13.

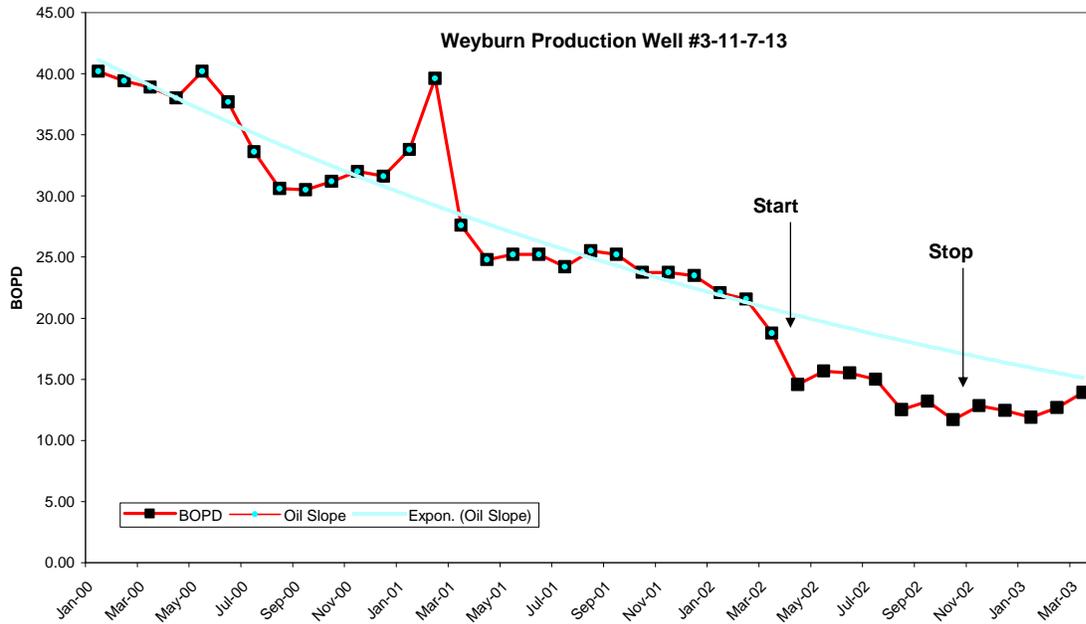


Figure 75. Weyburn 3-11-7-13.

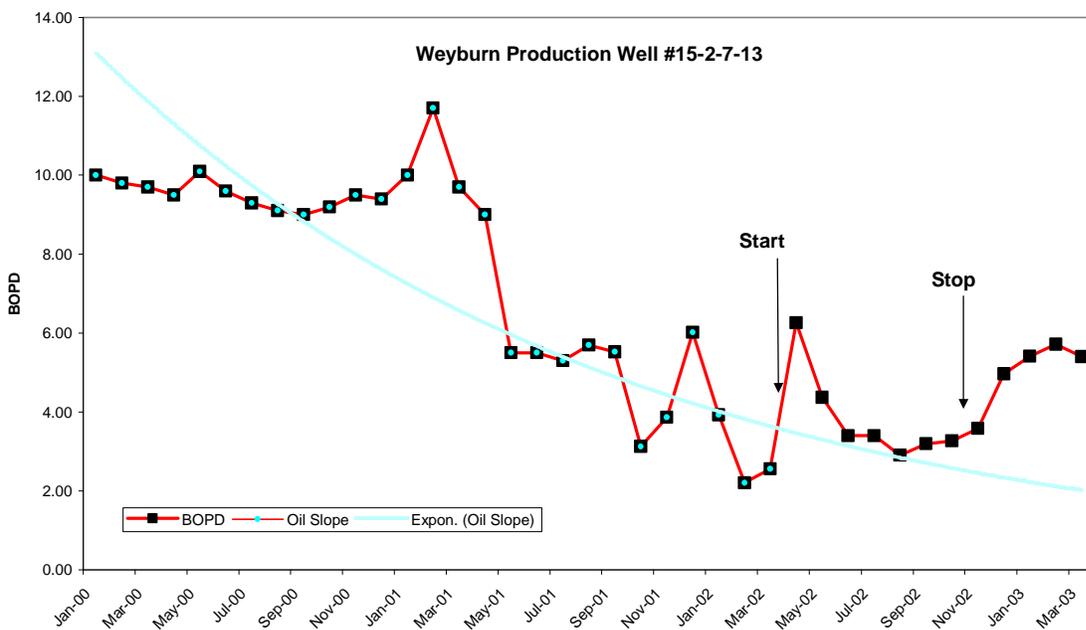


Figure 76. Weyburn 15-2-7-13.

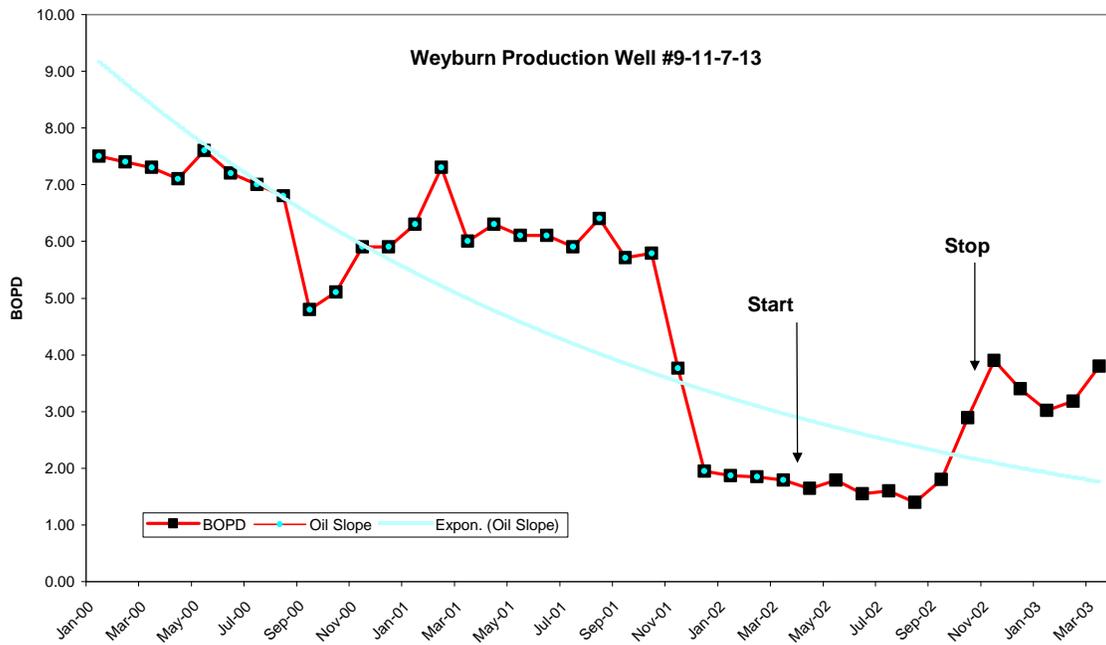


Figure 77. Weyburn 9-11-7-13.

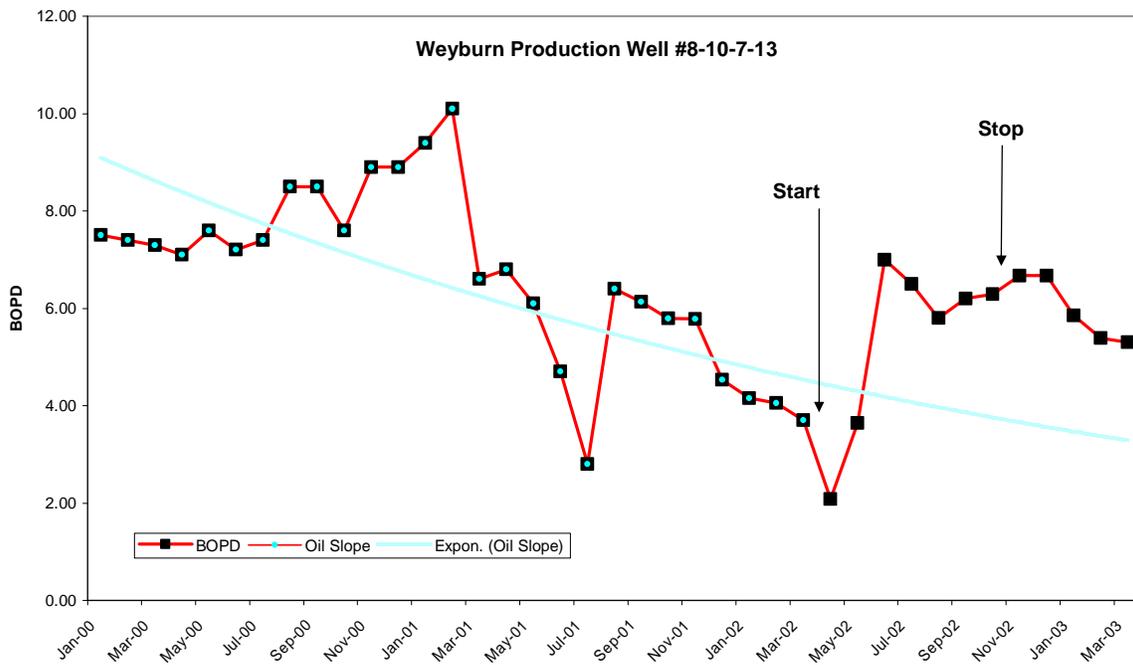


Figure 78. Weyburn 8-10-7-13.

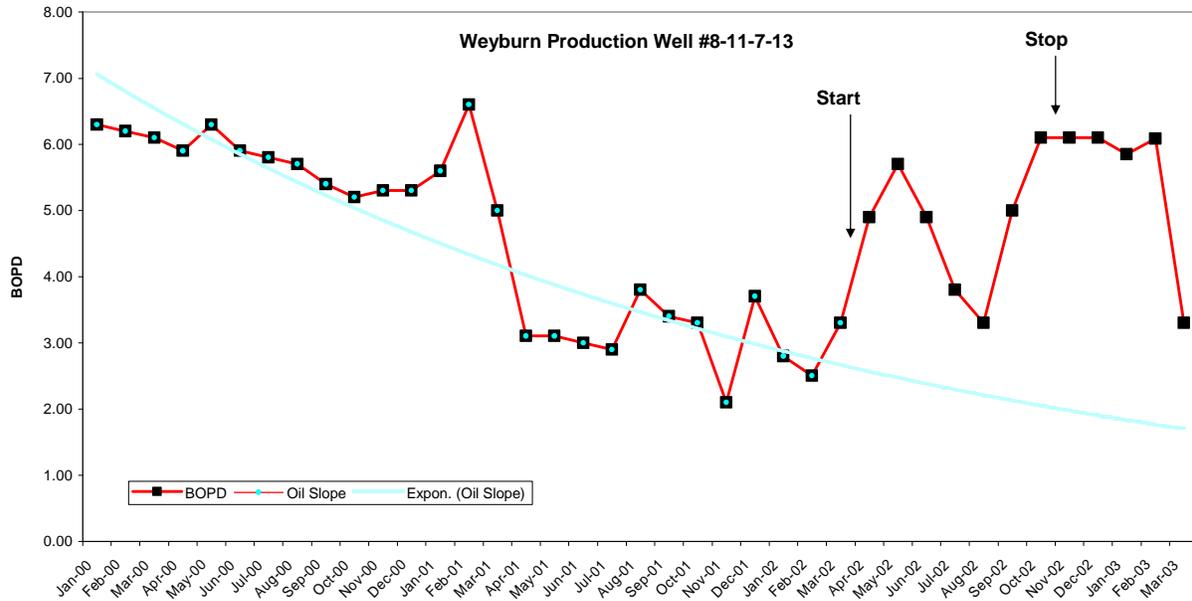


Figure 79. Weyburn 8-11-7-13.

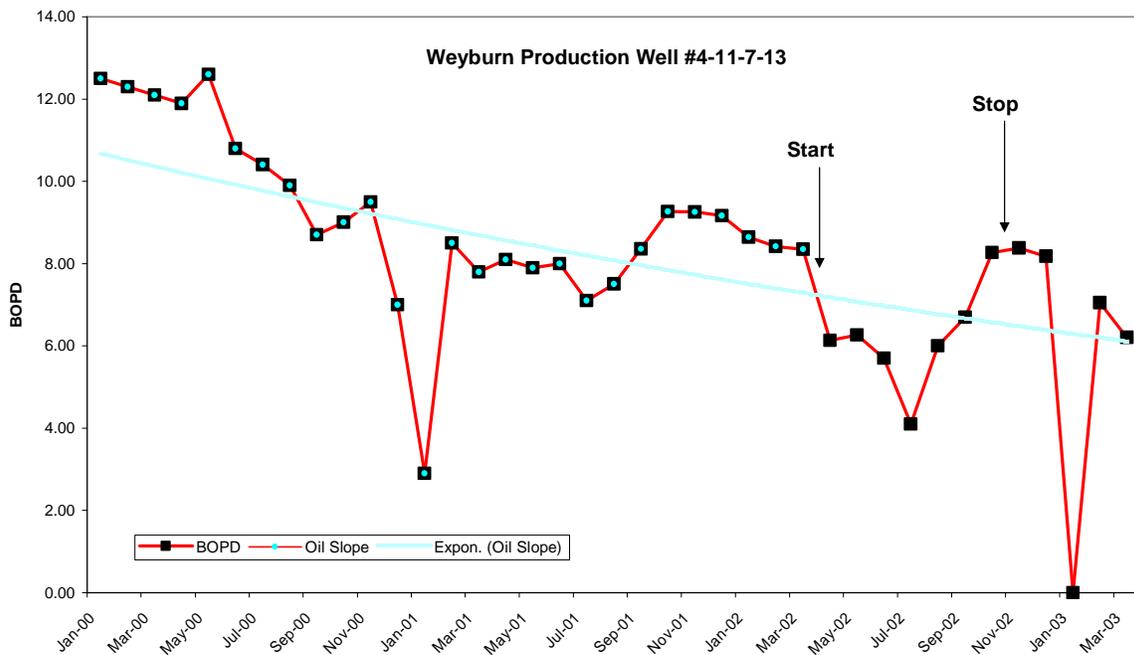


Figure 80. Weyburn 4-11-7-13.

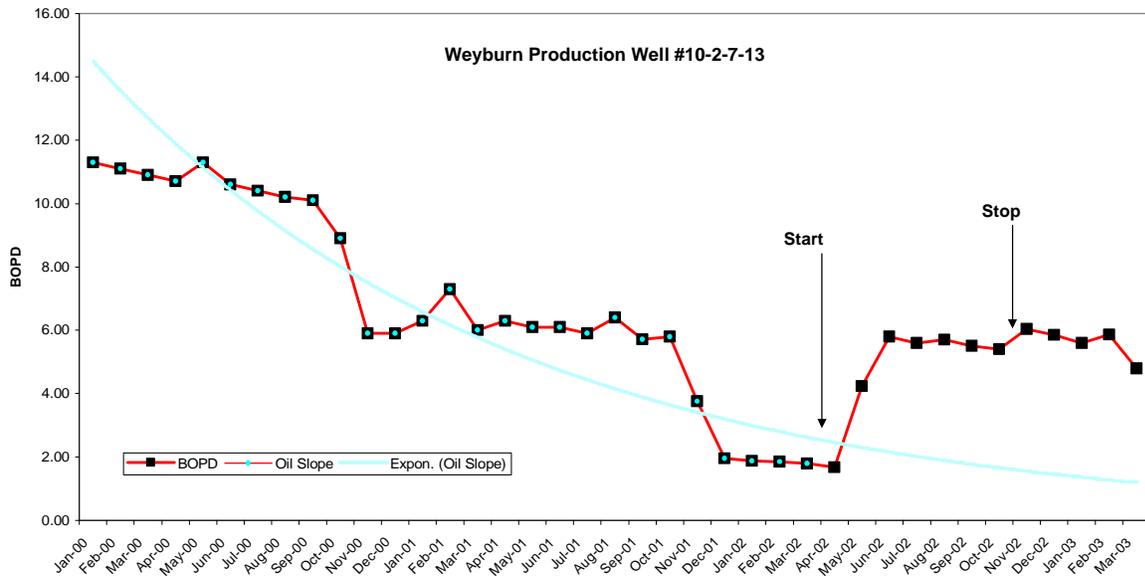


Figure 81. Weyburn 10-2-7-13.

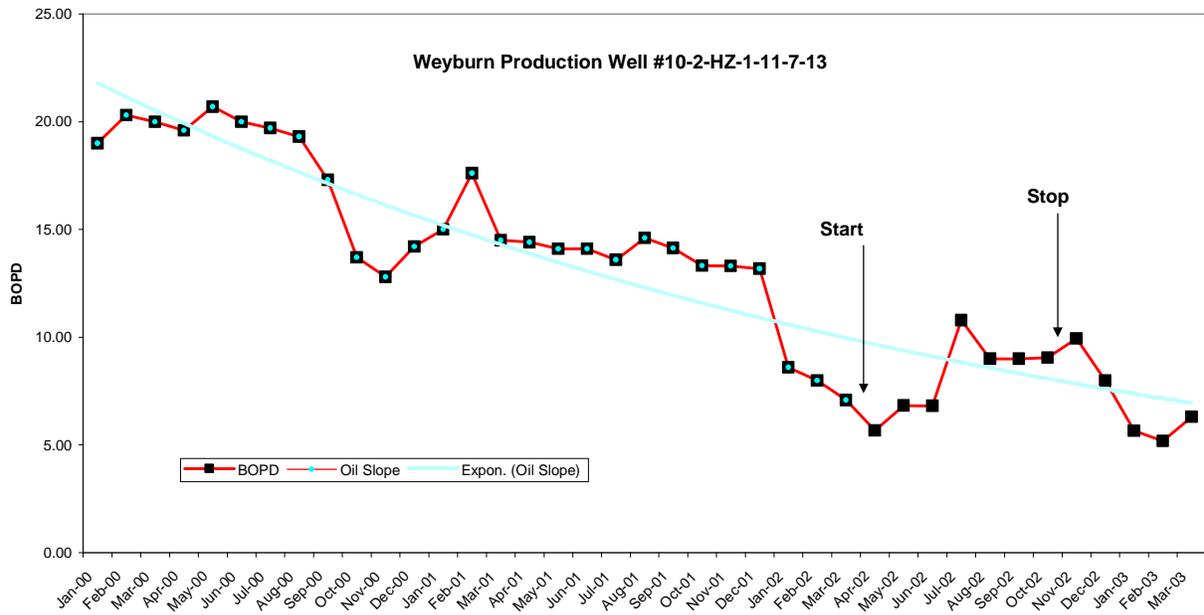


Figure 82. Weyburn 10-2-HZ-1-11-7-13.

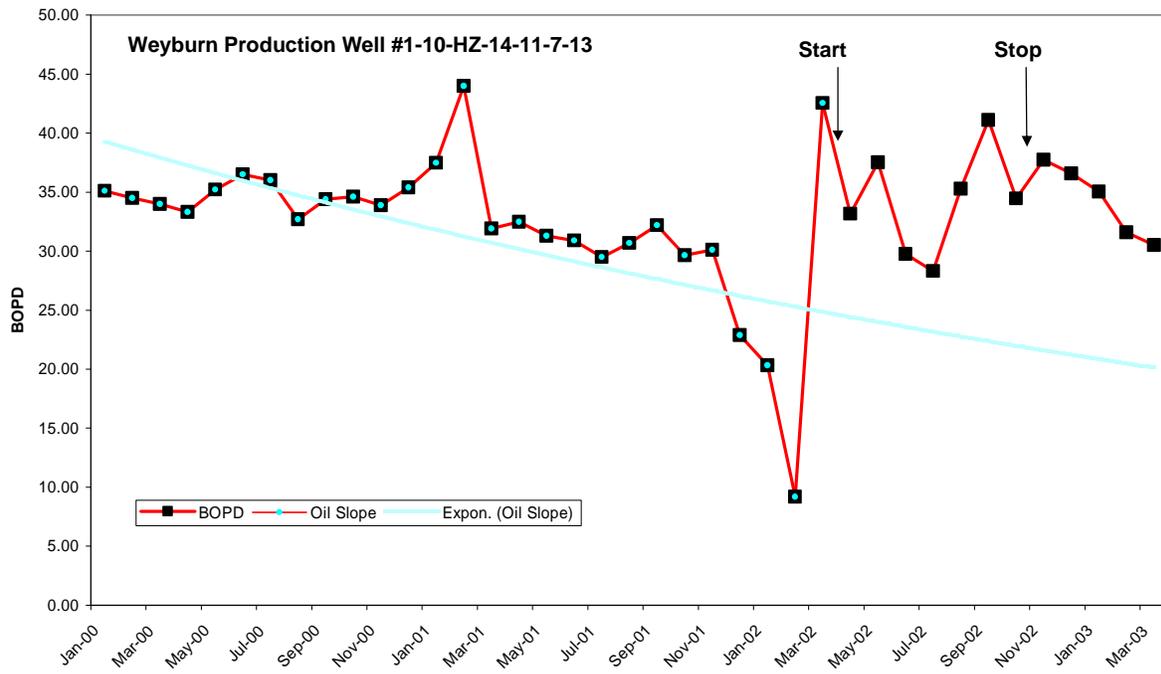


Figure 83. Weyburn 1-10-HZ-14-11-7-13.

Discussion of Laboratory and Field Investigations

A. Culture identification and selection

The experimental conditions that were set and which were the goal of the program involved development of cultures which would grow at conditions which would be encountered and expected in the majority of oilfield reservoirs that would be candidates for oil recovery floods. Cultures were obtained and or isolated from various sources including reservoir fluids, oilfield produced waters, hydrocarbon contaminated soil, and from our culture collection and stock. All of these cultures were tested using various media and conditions and it was evident that a wide variety of species could be grown. To limit the number of potential isolates, the growth conditions were defined to duplicate those of oil reservoirs. The major restrictive conditions established for such growth included salt concentrations of 3.5%, temperatures of 23°, 40°, and 55° C, and a strict anaerobic environment. The other major criteria for culture growth involved the selection of restrictive carbon and nitrogen macronutrient sources. Although initial isolation media contained growth factors such as yeast extract, it was determined that such growth factors were not required for the cultures selected for sandpack experimentation. Therefore the use of such growth stimulants was discontinued in flooding experiments and the flooding media composition more closely matched to the water that would be used in field studies. In addition while extra carbon sources such as glucose and sucrose would enhance growth and particularly polymer production, these more expensive carbon sources were not required or necessary for microbial growth, polymer production, or for the observed oil recovery. Thus, while this adherence to the defined set of growth criteria could be viewed as restrictive for the isolation of the largest number of cultures, the program centered on identifying and using cultures which had a realistic expectation of mimicking the microbial population that would be encountered and would grow within a large number of reservoirs and which would prove the feasibility of manipulating such a diverse reservoir microflora.

A large number of cultures that were isolated were maintained as stock cultures and would be available for further testing and examination. However, the test results from the numerous isolation and growth studies definitely established that good anaerobic microbial growth would occur in a simple brine flooding media which contained only acetate as the carbon source and nitrate as the nitrogen source. This finding of a naturally occurring carbon source (VFAs) in reservoir brines was paramount in designing flooding tests which would be representative of field conditions and allowed a rapid transition of the laboratory results to field application. The need for phosphate would probably be satisfied by its presence in the brine composition in the reservoir under field conditions and as a consequence was not added to most tests.

Examination of several field brines showed low concentrations of acetate were present. This would be expected in waters from these highly flooded and produced reservoirs. Even at these low concentrations the importance of the VFAs (principally acetate) which occur naturally in the reservoir waters is key to the development of the proposed microbial oil recovery system since it supplies the preformed, easily-metabolizable carbon source necessary for anaerobic microbial growth within the reservoir. The acetate, in the presence of introduced sulfate, is used by the sulfate reducing bacteria (SRB) to produce sulfide which causes reservoir souring and can cause corrosion. The developed technology is based on the presence of the acetate and on the replacement of the SRB population with the denitrifying (DNB) population which become

predominant in the presence of a nitrate-based formula as the alternate electron acceptor which replaces sulfate. Thus, the selection and isolation of cultures is governed by the carbon source and the nitrogen source and this deliberate adjustment of the nutrient requirement will have the desired effect of developing the selected population.

It should be recognized that the interrelationship of these key nutrient requirements and their ability to support prolific microbial growth of a desired microbial population at reservoir conditions had been observed in previous studies involved in the development of the Biocompetitive Exclusion (BCX) technology which altered the reservoir ecology to maximize growth of the DNB population which replaced the SRB population. These expanded and confirmatory tests on culture isolation of entirely new microbial populations using a minimal carbon and nitrogen source were important for their intended purpose of increased oil recovery. It should be noted that most of these cultures were from sources associated with oilfield operations and represented indigenous populations. Importantly, these cultures, when challenged by multiple passages through sandpacks at reservoir conditions, would be established as a mixed consortium of organisms which survived and proliferated at the designated growth conditions and performed in their intended role as agents causing oil release and recovery. Numerous tests demonstrated that the microflora could be manipulated and modified to produce oil recovery agents including viscosifying agents (biopolymers) and gases. The addition of sugars such as sucrose was most conducive for high levels of polymer production, as would be expected. However to produce this high polymer production a large amount of sucrose would be required, and although successfully demonstrated at laboratory conditions, would be difficult and expensive to implement in the field. It was considered that the problem of near-wellbore plugging could occur by the injection of the sugar due to the massive production of polymer immediately adjacent to the wellbore injection point. Thus the study demonstrated that while the composition of the various media could be modified selectively to produce specific products of value, such as biopolymer, for different oil recovery applications, the primary goal of minimizing nutrient growth requirements yet achieving increased oil recovery was pursued. The studies demonstrated that the employment and use of the indigenous microflora in the reservoir is the most feasible route to establish the desired population which makes the technology practical and low cost for field usage.

B. Sandpack Studies

The findings of the laboratory cultural studies were confirmed by the sandpack systems which were developed and tested. The various techniques that were tested had identified cultures having the desired characteristic of growing at reservoir conditions at minimum nutrient requirements and included studies that would demonstrate penetration and transport through sandpacks. The requirement for easy operation of multiple flooding tests in a screening mode to define the large number of variables which would be tested required that such flooding experiments be run in sandpack columns. Therefore the development of a versatile sandpack test system involved a progressively expanded series of test columns which varied in size from a short (7.5 cm) slim tube (6mm ID) through glass columns (25.8 cm in length by 1.27cm ID) to final 2inch diameter plastic PVC columns which were 10 ft long. The development of the flooding system for each series of sandpacks progressed from gravity flooding to controlled pumps which could be operated intermittently or continually. All sandpacks were operated at controlled temperatures and in an anaerobic condition. As initial results were obtained in the

smaller flooding systems, those conditions and nutrient formulations which gave the most favorable results would be retested in progressively larger flooding systems. This progressive screening of the microbial systems in the sandpacks provided an evaluation of the technology to be continually monitored and the results to be directed to closely match conditions that would be expected in the field. In later tests, the field waters and oil were obtained from the proposed field test area to simulate the field conditions.

The small columns were packed with Mill Creek sand which was easy to obtain, was uniform in size, had good flow and packing characteristics, and was white, which made visualization of effects easily observed. The sand could be sieved to any desired mesh but for convenience was usually used as received following washing to remove any extraneous nutrients and matter that could be present. The large 10 ft tubes were packed with a brown unwashed sand. The tubes were always packed with dry sand and then flooded with water (brine) followed by the oil flood. Standard flooding protocols to obtain residual oil contents in preparation for the controlled microbial floods were followed. The glass columns were capped with thick black butyl rubber stoppers or with red stoppers. These closures allowed hypodermic needles to be used yet remained anaerobic after multiple needle penetrations. Simple sandpack columns could be made to any dimension and flooded under a variety of conditions which maximized their operational parameters. The smaller columns could be incubated in incubators or ovens, while the 10 ft long sandpack systems were heated with heating tapes or heat lamps and the temperature was held constant with insulation blankets. The sandpacks could be mounted horizontally or vertically and tests were made at both conditions. Although individual variations in oil recovery could be observed between horizontal and vertical flooding positions, the effects of the microbial growth were dominant regardless of whether the sandpack was vertical or horizontal. These simple to fabricate and operate sandpack columns allowed a large number of duplicate and multiple tests to be made during the course of the program. The sandpacks were flooded at all flow conditions from intermittent to continuous, or shut in for any period of time desired.

Examination of each series of sandpack tests showed the results, comparison, and evaluation of each variable tested within the test series. As would be expected in biosystem operations, there was variation in some test data but in general the results offered reasonable reproducibility which allowed the trend of defining the role of microbial growth in oil recovery to be observed. An examination of the composite data from these laboratory and sandpack studies allows a review and analysis of the overall results to be made.

The sandpack results show that microbial growth, products, and actions are dominant in causing the observed increased oil recovery and without microbial growth there was little or no increased oil recovery.

This result was confirmed in field tests.

C. Overall Results

To establish and support the important finding that increased oil recovery is due to microbial growth and products and to define the biosystem operational conditions and limitations the following general statements, observations, and evaluations are presented:

1. Large numbers and many species of microorganisms can be isolated from samples that are representative of oil reservoir environments.

2. The cultures isolated constitute an indigenous anaerobic mixed consortium which is capable of growth at temperatures of at least 50° C.

3. Alterations of growth media constituents allow a predominant microbial consortium with specific growth characteristics to be selected.

4. Increased nutrient addition which stimulates increased microbial growth will increase oil recovery but even low concentrations of nutrients have a positive effect on oil recovery.

5. Large numbers and diverse microbial consortia can be isolated and will grow readily in the presence of acetate and nitrate at anaerobic conditions. Acetate was identified in natural reservoir brines from several fields which indicated that an acetate utilizing population had been established. Increasing the level of acetate increased microbial growth, which was further enhanced by increased levels of nitrate as the nitrogen source.

6. Biopolymers can be selectively produced which increase the viscosity and substantially reduce the flowrate. The addition of sucrose increases polymer production and offers a potential biosystem for mobility control and water diversion application, but the formation of biopolymers will occur in its absence.

7. Microorganisms readily penetrate through sandpicks at all flow rates and conditions and in the presence or absence of oil.

8. The indigenous anaerobic microflora can be altered in type and number by the addition of nitrate which increases the population of a consortium of denitrifying microorganisms. In natural waters a stimulation of the denitrifying population reduces the number and activity of the sulfate reducing population.

9. The addition of nitrate in the presence of acetate stimulated the microbial population to produce additional oil. However in the presence of additional acetate, the combined levels of acetate and nitrate together gave the highest oil recovery values. The data demonstrated that reservoirs that have the highest levels of acetate would be the best candidates for oil recovery when treated with nitrate. This indicates that the application of the alternate electron acceptor process would be most effective when applied early in a waterflood operation when the VFA content was at its highest and prior to its removal by SRB or by dilution with waters which contain no VFA. Thus the concentration of the VFA in the reservoir can be a governing nutrient for increasing oil recovery.

10. Both light and heavy oil can be released by microbial action and the data indicate that the microbial system for oil recovery is independent of oil type or characteristics.

11. The addition of selected proprietary nutrient amendments (Nutrient T) can increase oil release, especially in the case of heavy oils. The use of additional carbon sources would become more important in reservoirs with low VFA concentrations or in heavy oil reservoirs where stimulation of microbial populations are required.

12. Increased oil recovery occurred in both horizontal and vertical sandpacks (10ft in length) and either system would demonstrate increased oil recovery due to microbial action.

13. The recovery of oil is time-dependent rather than volume dependent and demonstrated that oil recovery was due to microbial action rather than system operations.

14. The use of special formulations of the Maxwell treatment which are designed for a specific waterflood brine and field will increase oil production while synergistically preventing and removing biogenic sulfide.

The large number of sandpack floods demonstrated that increased oil recovery occurred due to microbial actions with a variety of nutrient formulations. However, most important were the results which demonstrated that increased oil recovery will occur readily in the presence of acetate and the nitrate-based formula. This indicated that a practical microbial oil recovery process could be employed which required only the addition of simple nitrogen-based alternate electron acceptor sources, since the necessary carbon source was already present in the formation in the form of acetate. The addition of the alternate electron acceptor caused the reservoir microflora to become predominantly a denitrifying bacterial population requiring only acetate and nitrate-based formulae for its proliferation and dominance. As experience was gained by sandpack and field treatments, the use of Maxwell formulations generally was observed to increase the rate of oil recovery as well as the amount of oil recovered. There is no need for the addition of microbial cultures to establish this new microbial consortium since the indigenous population in the reservoir responds without any need to be supplemented by additional inocula.

While the observed increased oil recovery occurs as described, the specific mechanisms of oil increase remains elusive since the proliferation of the new denitrifying populations cause multiple changes in the flood waters. These measured or observed changes included gas production (N_2 , CO_2 , and CH_4), polymer, solvents, and surfactant production, and biomass formation. Each of these agents has been identified as factors which can cause increased oil release and recovery. However the combined effects of such agents are difficult to determine and to model. While individually each of these oil releasing systems has been well studied by conventional EOR technologies and have been applied in field operations, the consideration of multiple agents is neglected by the oil industry since application of multiple systems would be considered as being too difficult or expensive to employ. In contrast, the multiple effects which are observed in biosystems are the normal result of microbial growth. Thus, while it is possible to have a biosystem produce a predominant agent such as polymer or gas production, the other agents and actions will also be present, although in smaller amount, and yet their combined

effect may have synergistic action. Since the biosystem is in a constant dynamic state, the ratio, quantity, and interrelationship of such agents and actions are constantly changing. This is due to changes in microbial populations, both in numbers and types, and in the metabolic actions within a population. As the population responds in the reservoir to an added nutrient, the shift in population occurs, with some species increasing while others decrease, and, as important, the products from one species cause alterations in the succeeding population. While it may be possible to determine oil releasing mechanisms with pure cultures in very controlled laboratory conditions, this situation becomes much more difficult with mixed microbial cultures, even in controlled laboratory experiments, and almost impossible in field operations where the biosystems are beyond sampling control. Thus, although the specific mechanism for microbial oil recovery may not be definitively identified (except under laboratory conditions), the overall effect of increased oil recovery does occur due to the combined effects of the increased microbial growth and production of multiple oil-releasing bioproducts. However, it is also important to recognize that the microbial population can be altered and manipulated by the selection of the carbon and nitrogen source as demonstrated by these studies which utilized only acetate and nitrate-based formulae. It can be anticipated that the addition of selected nutrients in addition to these basic nutrients would develop an alternate population which could be designed for a specific oil recovery function such as polymer enhancement by sugar addition.

Additionally and significantly, as previously noted— accompanied by charts that show flooding results— an early expansion of the project focused a part of our laboratory investigation into possible recovery of so-called heavy oil. In this instance, Kern County, California 13° API gravity oil was challenged with several flooding techniques, protocols, and formulae to determine if MEOR principles could be employed to recover this heavy oil resource in a manner that is significantly different and at less cost than traditional heavy oil recovery processes. The results of the laboratory flooding trials confirmed and exceeded our expectations. The development of this new heavy oil recovery technology will continue to be pursued.

These data suggest that next generation oil recovery systems will be tailored and directed to such controlled modifications and manipulation. Preliminary studies using proprietary nutrients were initiated toward this goal and indicated such treatments were feasible but would involve additional costs and handling problems which must be resolved for development of a specialized system. On the other hand, at this time the most important goal is to develop a practical and economical microbial oil recovery system that will recover a significant amount of additional oil and that is accepted and widely used by the oil industry.

This program has achieved the goal of demonstrating a technology for increasing oil recovery by the laboratory development of a technology which successfully altered the reservoir ecology by establishing a predominant denitrifying microbial population by the addition of the selected alternate electron acceptor. This new population was shown to increase oil recovery in sandpicks and the studies were expanded to study field waters and oil from reservoirs which were potential candidates for field pilot projects. The results indicated that the technology could be used in the field and field projects were initiated and completed using a Maxwell technology. Thus the primary objective of the research program of increasing oil recovery by a modification of the reservoir ecology was demonstrated and a practical technology for field usage is offered to the oil industry.

Summary and Conclusions

This report presents the findings of laboratory experimentation complemented by field data leading to the development and usage of a new successful and practical technology for increasing oil recovery. The laboratory tests demonstrated that the reservoir ecology could be modified by the addition of an alternate electron acceptor salt which acted in conjunction with the naturally occurring VFA content of the reservoir brines. This unique combination of nutrient requirements resulted in the proliferation of the indigenous reservoir microflora which produced metabolic reactions and products which enhanced oil release and increased oil recovery. The development of the Maxwell treatment formulations allowed a dual sulfide reduction system to be synergistically incorporated into a technology which produced significant increased oil recovery. This new technology offers and presents to the oil industry a practical, low cost, and successful methodology for increasing oil recovery from fields which face oil production declines and possible abandonment.

The key findings and guides for the development of a successful microbial oil recovery technology can be summarized as follows:

1. The reservoir environment consists of a variety of microorganisms which make up a microbial consortium.
2. A reservoir consortium is dependent on environmental conditions and the nutrient composition of the specific reservoir brine.
3. A large number and variety of microbial cultures and species can be isolated from oilfield reservoir environments at temperatures of 30-70 °C.
4. The isolation techniques and nutrient composition will govern the types of cultures isolated.
5. Nutrient formulations can be adjusted to favor the isolation and growth of a predominant species from a microbial consortium.
6. An easily utilizable and in some cases preferred carbon source in the reservoir environment is the presence of the naturally occurring volatile fatty acid (VFA) content of the brines.
7. The utilization of the VFA as the only added carbon source allows the growth of a reservoir-adapted indigenous microflora to be isolated and grown.
8. The indigenous microflora can be manipulated and modified as to numbers, types, metabolic reactions, and production by the changes in carbon and nitrogen macronutrient content.
9. The modification of the carbon requirement by the introduction of sugar can lead to increased polymer production.
10. The introduction of an alternate electron acceptor such as nitrate in combination with the VFA shifts the microbial populations to become a predominantly denitrifying bacteria (DNB) population.
11. The DNB population will preferentially use the VFA in the presence of nitrate thereby denying this carbon source to the sulfate reducing bacteria (SRB) and result in a biocompetitive exclusion of the SRB.
12. The DNB consortium utilize the VFA and nitrate-based formulae to produce gases (N₂, CO₂), polymers, surfactants, solvents, etc., which are products and agents that have oil releasing, transport, and recovery effects.
13. The ability to modify and establish a DNB consortium which increases oil recovery can be achieved by understanding the VFA and nitrate-based formulae relationship and interaction.

14. Sandpack columns provide an easy to construct model system to demonstrate microbial oil recovery.
15. Sandpack columns allow a large number of tests to be run concurrently which provide the necessary variety and alterations to be incorporated in multiple test series of oil recovery studies.
16. Sandpack columns can be run under a variety of environmental conditions and are easily scaled up to large size for use with different field brines or oils.
17. Sandpack systems could be flooded successfully at 3.5% salt and up to 50 °C with anaerobic microbial populations.
18. Nutrient requirements and conditions can be easily adjusted in sandpicks to maximize test conditions and alterations during the course of the flooding tests.
19. Each adjustment of nutrient formulation will be reflected in microbial growth and product production and in changes in oil recovery results.
20. Multiple sand pack flooding tests demonstrated that increased microbial growth would increase oil recovery while studies in the absence of microbial growth resulted in essentially no increase in oil production.
21. Oil recovery in sandpack studies with heavy oils was improved by the addition of the proprietary Nutrient T formulation.
22. Successful oil recovery increases with light oils could be demonstrated in sandpack studies using only indigenous microorganisms with acetate and nitrate-based formulae requirements.

These laboratory results were complemented by field tests that employed the developed and improved microbial oil recovery technology involving use of the naturally occurring VFA constituents in the reservoir waters in the presence of the an injected alternate electron acceptor salt formulation (the Maxwell treatment).

23. Recognition of interrelation between the VFA content and the nitrate-based formulae developed the Maxwell formulations which offer the maximum stimulation of the indigenous DNB microflora in targeted reservoirs and the greatest oil recovery.
24. The analysis, examination, and correlation of laboratory data with field data will optimize treatment levels, content, and protocols to demonstrate oil recovery in both systems.
25. Reported oil recovery increases in Maxwell-treated waterflood field tests exceed those observed in laboratory studies, however direct annular treatments of producing wells did not show a consistent expected increase.
26. Waterflood oil recovery in a California oilfield increased by 21% while increases of 24% were reported in a Canadian field with the use of a Maxwell formulation.
27. No problems were reported in any field test for oil recovery as a result of employing the Maxwell treatment.
28. The developed microbial oil well treatment system is operator and environmentally friendly and requires little capital expense for its usage.
29. The new system requires no added microbial cultures or special expensive chemical additions or other reservoir conditioning such as the introduction of air.³⁰ The system is designed for anaerobic conditions which are already present in the reservoir.
30. The Maxwell treatment components and composition introduce a unique system for maximizing beneficial microbial growth and product formation for oil recovery which surpasses the use of only nitrate as the sole alternate electron acceptor.

31. The system is not constrained by reservoir environmental conditions since it will operate in any reservoir which already has an indigenous microbial population.

The program has developed and introduced to the oil industry a new technology which is practical, low cost, easily implemented, and is successful for increasing oil recovery. The use of Maxwell technology is now being expanded in field trials by the oil industry.

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Technology Transfer

The findings of these laboratory studies and field test results were made available to the oil industry by presentation, exhibits, and publications. The importance of the major conclusion: namely that a significant increase in oil recovery resulted from microbial growth due to an alteration of the reservoir ecology was stressed. The technology demonstrated a practical, effective, and low cost system and offers industry a new improved IOR technology. The technology was introduced by the following presentations and publications and in addition discussions have been held with representatives from several oilfields concerning field applications.

Presentations and publications

Hitzman, D. O. and S. A. Bailey. 2000. Innovative MIOR Process Utilizing Indigenous Reservoir Constituents. DOE Semi-Annual Report, January 2000.

Hitzman, D. O., S. A. Bailey, and A. K. Stepp. 2000. Innovative MIOR Process Utilizing Indigenous Reservoir Constituents. DOE Semi-Annual Report, July 2000.

A presentation on the project was made at the Oil Technology Program Contractor Review Meeting in Denver in June 2000 by Scott Bailey.

Hitzman, D. O. and A. K. Stepp. 2001. Innovative MIOR Process Utilizing Indigenous Reservoir Constituents. DOE Semi-Annual Report, January 2001.

Hitzman, D. O., A. K. Stepp, D. M. Dennis, and L. R. Graumann. 2001. Innovative MIOR Process Utilizing Indigenous Reservoir Constituents. DOE Semi-Annual Report, October 2001.

Hitzman, D. O., A. K. Stepp, D. M. Dennis, and L. R. Graumann. 2002. Innovative MIOR Process Utilizing Indigenous Reservoir Constituents. DOE Semi-Annual Report, April 2002.

Hitzman, D. O., A. K. Stepp, D. M. Dennis, and L. R. Graumann. 2002. Innovative MIOR Process Utilizing Indigenous Reservoir Constituents. DOE Semi-Annual Report, October 2002.

Dennis, D.M.. 2003. Presentation to Canadian Oil & Gas Industry, March 2003, Calgary, Alberta.

Presentations as part of GMT Exhibit Booth

Society of Geophysicists (SEG) Annual Convention, October 31-November 5, 1999, Houston.

GEO 2000, Middle East Oil and Gas Exposition, March 27-29, 2000, Bahrain.

Society of Petroleum Engineers (SPE) DOE Improved Oil Recovery Symposium, April 2-5, 2000, Tulsa.

American Association of Petroleum Geologists (AAPG) Annual Convention, April 16-19, 2000, New Orleans.

NAPE (North American Prospect Exposition), January 31-February 1, 2001, Houston.

AAPG, March 9-13, 2001, Dallas.

SPE, March 24-27, 2001, Oklahoma City.

Oklahoma Geological Survey, May 8-9, 2001, Oklahoma City.

AAPG Annual Convention, June 2-7, 2001, Denver.

CSPG (Canadian Society for Petroleum Geologists), Annual Convention, June 16-20, 2001, Calgary.

SEG Annual Convention, September 9-12, 2001, New Orleans.

AAPG East Section Meeting, September 23-25, 2001, Kalamazoo, Michigan.

NAPE, January 29-31, 2002, Houston.

AAPG Annual Convention, March 10-13, 2002, Houston.

Kansas Geological Society, March 28, 2002, Wichita, KS.