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What Has Been Learned From A Hundred MEOR Applications

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Abstract

Using a breakthrough process, which does not require microbes to be injected, over one hundred Microbial Enhanced Oil Recovery (MEOR) applications have been conducted since 2007 in producing oil and water injection wells in the United States and Canada. On average, these applications increased oil production by 127% with an 89% success rate. This paper reviews the MEOR process, reviews the results of the first one hundred plus applications and shares what has been learned from this work.

Observations and conclusions include the following:

1. Screening reservoirs is critical to success. Identifying reservoirs where appropriate microbes are present and oil is movable is the key.
2. MEOR can be applied to a wide range of oil gravities. MEOR has been successfully applied to reservoirs with oil gravity as high as 41° and as low as 16° API.
3. When bacteria growth is appropriately controlled, reservoir plugging or formation damage is no longer a risk.
4. Microbes reside in extreme conditions and can be manipulated to perform valuable in-situ "work." MEOR has been applied successfully at reservoir temperatures as high as 200°F and salinities as high as 140,000 ppm TDS.
5. MEOR can be successfully applied in dual-porosity reservoirs.
6. A side benefit of applying MEOR is that it can reduce reservoir souring.
7. An oil response is not always seen when treating producing wells.

The application of MEOR can be applied to many more reservoirs than originally thought with little downside risk. This review of more than a hundred MEOR applications expands the types of reservoirs where MEOR can be successfully applied. Low risk and economically attractive treatments can be accomplished when appropriate scientific analysis and laboratory screening is performed prior to treatments.

Introduction

From July 2007 through the end of 2010, there have been one hundred and six applications of MEOR to enhance recovery of North American waterfloods in a programmatic approach to organic oil recovery. The application of this process typically consists of five steps: 1) initial field screening, 2) well sampling and laboratory analysis, 3) In-situ Microbial Response Analysis (ISMRA™), where the nutrient formula developed in the laboratory is applied to a producing well to assure the microbial response under field conditions replicates lab results, 4) pilot testing (if applicable) in a representative portion of the waterflood and 5) full-field application. Thirty-eight treatments have been applied to thirty-five producing wells and sixty-eight treatments have been applied to thirty injection wells. From the results available to date, on average, the wells and their adjacent producers have seen an oil production increase eighty-nine per cent of the time. On average, these applications have resulted in a 127% increase from pre-treatment rates to post-treatment maximum rates. Table 1 shows the results available as of January 1, 2011.

Table 1. Over one hundred applications were performed in 65 wells through 2010.

	Number of Wells	Number of TMTs	Number of Increases	Success Rate	% Oil Increase
PRODUCERS					
ISMRAs	22	24	16	73%	228%
Producers	13	14	12	92%	176%
Subtotal	35	38	28	80%	205%
INJECTORS					
Confirmed Results	27	60	27	100%	47%
Pending	3	8			
ALL WELLS					
Confirmed Results	62	98	55	89%	127%
Pending	3	8			
TOTAL	65	106			

Although economics are pending on many of these projects, we know this organic recovery process can be applied for $6 per incremental barrel of oil (Town, K. 2010).

Oil Release Mechanism

Unlike many previous attempts at MEOR, this process does not attempt to introduce bacteria into the oil-producing reservoir (Sheehy, A. 1990). Instead, indigenous bacteria are stimulated to grow and reproduce with a reservoir-specific mixture of environmentally benign nutrients. The approach needs to be customized to accommodate the different bacterial ecologies in each reservoir. In the ideal application, the water injection system becomes the transport medium for the nutrients, distributing the nutrients through the reservoir. By activating certain species of bacteria, changes in the flow characteristics of the oil are affected and induce the reservoir system to release additional oil to the active flow channels (Town, K. 2010). Stimulated microbes act at the interface of reservoir oil and water altering the flow potential in the producing formation. In the higher permeability portions of the reservoir, newly released oil, water and bacteria may interact to form a transient (temporary) micro-emulsion that may alter the sweep efficiency of the injected water as it moves through the reservoir. Based on laboratory data, it is believed that in a waterflood, this process can recover up to an additional 10% of the original-oil-in-place. (Davis C. P. 2009)

Discussion & Results

1. Screening reservoirs is critical to success. Through the first one hundred applications (measured by increased oil production) the success rate is very high at approximately 90%. It is believed that the screening process is the major factor in delivering this high success rate. Identifying reservoirs where bacteria are present and oil is movable is the key to MEOR success.

Bacteria must be present in the reservoir since no bacteria are injected. Typical initial screening criteria for the presence of bacteria in oil reservoirs are: reservoir temperature of less than 80°C (180°F) and water salinity below 10%, 100,000 ppm Total Dissolved Solids (TDS). Also, pH should be neutral, 6 to 8. Since this process does not add any energy to the system or change the characteristics of the oil, it should be historically documented that the oil is movable. The best documentation of movable oil is waterflood response. If the field has a documented waterflood response and appropriate bacteria are present, it should respond favorably to MEOR treatments. Typically this means MEOR applications are limited to reservoirs with oil gravity of 20° API gravity and above. However, as noted later in this paper successful treatments have been conducted on reservoirs with oil gravity as low as 16°API. The bottom limit of oil reservoirs where this process can be successfully applied is not yet known.

It is preferred to work in reservoirs with active water injection or water drive. In addition to providing energy, the water carries and distributes the nutrients throughout the reservoir. Reservoir permeability greater than 50 md is preferred, although the main objectives are injectivity and ability of the released oil to move to the producers. If a reservoir meets all of these conditions, it is an ideal candidate for MEOR application.

The second step in reservoir evaluation is well sampling of produced fluids and a rigorous laboratory analysis. Fluid samples are analyzed to determine if indigenous bacteria can be manipulated. If appropriate bacteria are present, the lab work continues to develop a nutrient formulation specifically suited for this reservoir.

2. MEOR can be applied to a wide range of oil gravities. In the first one hundred applications, a wide range of oil gravities has been treated. The highest gravity oil to be treated is 41°API gravity oil in the Devonian sandstone in Alberta, Canada. The lowest gravity oil to be treated is 16°API gravity. This has occurred in two locations, the Sparky sandstone in Alberta, Canada and the Upper Topanga Sandstone (Miocene) offshore California. All three reservoirs have shown good waterflood response. Some of the reservoir parameters are shown in the table below.

Table 2. Parameters for various reservoirs where MEOR has been successfully applied.

RESERVOIR	Devonian Sandstone	Sparky	Upper Topanga	Hauser	Sparky C
Oil Gravity, °API	41	16	16-18	22-26	20
Depth, Meters (feet)	1,056 (3,466)	600 (1,970)	1,585 (5,200)	1,650-2,636 (5,413-8,647)	661 (2,169)
Temperature, °C (°F)	49 (120)	20-25 (68-77)	71-74 (160-165)	88-93 (190-200)	26 (79)
Pay Thickness, meters (feet)	9 (29)	2-4 (6-13)	15-46 (50-150)	14-76 (45-250)	4 (13)
Permeability, md	300	700	100-1,000	10-100	600
Porosity, %	14-16	16	26	18-30	30
Salinity, ppm TDS	142,600	80,642	35,000	18,900	70,000
Cumulative Recovery, % OOIP	22	6	20	*	34
Current Water Cut, %	98	95	85	85	88

*Unknown, because zones commingled.

Results of applying MEOR in these extreme gravity reservoirs have been impressive. In the Devonian reservoir that has 41-gravity oil, an ISMRA™ was conducted in a producing well in April 2008. The well saw an increase in production from 2.5 m^3/d oil (16 bopd) + 29.2 m^3/d water (184 bwpd), 92 % water cut to 5.1 m^3/d oil (32 bopd) + 29.1 m^3/d water (183 bwpd), 85 % water cut. See production Figure 1. Subsequently, a pilot project was initiated in this reservoir.

The ISMRA™ in the 16-gravity Sparky reservoir conducted August 2010 saw outstanding results. Production went from 1.4 m^3/d oil (9 bopd) + 22.9 m^3/d water (144 bwpd), 94% water cut to 9.0 m^3/d oil (57 bopd) + 51.0 m^3/d water (321 bwpd), 85% water cut. See Figure 2. Since this field only has five injectors, a full-field application is currently being conducted.

At another 16-gravity reservoir, three injectors have been treated in an Upper Topanga reservoir. The ISMRA™ in this reservoir saw a production increase in the treated producer from 28.7 m^3/d oil (181 bopd) + 177 m^3/d water (1,113 bwpd), 86% water cut to 42.2 m^3/d oil (266 bopd) + 169 m^3/d water (1,065 bwpd), 80% water cut. Although the ISMRA™ response was short-lived, a pilot was initiated and later expanded. The pilot injector was treated three times. After the third treatment, well tests of the offset producers increased 7% from 403.m^3/d oil (2,539 bopd) + 3,660 m^3/d water (23,055 bwpd), 90% water cut to 430 m^3/d oil (2,707 bopd) + 3,241 m^3/d water (20,419 bwpd), 88% water cut. The pilot was expanded with the treating of two additional injectors. See Figure 3 for an example of an offset producer, responding to injector treatments.

3. Reservoir plugging or formation damage is no longer a risk. Historically, MEOR has often been associated with reservoir plugging. No doubt biomass is created when bacteria growth is stimulated. The formation of biomass can be a problem in injectors, even when not associated with MEOR treatments. Utilizing the nutrients in the water, bacteria growth can be stimulated and too much biomass can plug wells. A typical example is the documented plugging of injectors in the East Beverly Hills and San Vincente fields (Cusack, F. 1985 & 1987).

Through 106 applications there have been no indications of any perforation or formation damage. This high rate of successful applications is due to two major changes between the current and past practices of MEOR application. First, bacteria are not injected. It is believed that one of the reasons for reservoir plugging in the past was the practice of injecting bacteria, which could plug small pore throats in the reservoir. Second, glucose nutrients are not used in the current process. Injecting glucose nutrients stimulates the growth of too wide a variety of bacteria. Uncontrolled biomass growth can result in excessive growth and lead to reservoir plugging. There has been considerable work done in the area of controlled biomass growth to optimize waterflooding by changing the sweep (Brown, L 2000).

4. Microbes reside in extreme conditions and can be manipulated to perform valuable in-situ "work." MEOR has been applied successfully at reservoir temperatures as high as 93°C (200°F) and salinities as high as 142,000 ppm TDS. An application in the Hauser formation in California has demonstrated successful MEOR application (Zahner, B. 2010) in a reservoir that ranges in temperature from 88-93°C (190-200°F). Before treatment the ISMRA™ well was producing about 4.4 m^3/d (28 bopd) + 30.3 m^3/d (91 bwpd). After peaking at 17.8 m^3/d (112 bopd) + 11.4 m^3/d (72 bwpd) the well tests averaged 12.5 m^3/d (79 bopd) and 30.3 m^3/d (91 bwpd) for the next three months. It is estimated that this single treatment yielded 4,500 barrels of incremental oil. Because this field only has three injectors, full field MEOR application was initiated. Other parameters of this reservoir are listed in Table 2.

The previously mentioned Devonian reservoir has a water salinity of 142,600 TDS. Reservoir parameters of this reservoir are listed in Table 2 and the previously mentioned successful ISMRA™ application can be seen in Figure 1. The biological environment of this reservoir was limited (due to limited species being present), but still provided a window of opportunity to successfully improve flow characteristics.

5. MEOR can be successfully applied in dual-porosity reservoirs. There is concern as to whether MEOR can be applied in dual-porosity reservoirs. The biggest concern in applying MEOR to dual-porosity systems is whether the nutrients are able to penetrate the matrix or remain in the high permeability streaks and bypass the matrix. An application in a Sparky reservoir, in Alberta, Canada has proven that dual porosity reservoirs can be treated. One of the unique characteristics of this reservoir is that it contains wormholes, high permeability channels that form within the reservoir (Tremblay, B 1999). The permeability, which has been reported as high as thirteen darcies (Yuan 1999), is so high that communication between some injector/producer pairs is measured in hours. This compares to months in more homogeneous reservoirs. The ISMRA™ in this Sparky reservoir was conducted in January 2009. Production in this producer increased from 1.3 m^3/d oil (8 bopd) + 14.4 m^3/d water (91 bwpd), 92% water cut to a peak of 6.2 m^3/d oil (39 bopd) + 14.8 water m^3/d (93 bwpd), 71 % water cut. As an indication of how permeable wormholes can be, it was noted that three 20-acre offset wells to the producing ISMRA™ well responded to nutrient stimulation. Post-treatment while the ISMRA™ well was shut in, it is believed that the nutrient material migrated through wormholes to the northeast stimulating bacterial growth and oil response in the broader area. On average, the three offsets increased from 1.2 m^3/d oil (8 bopd) + 20 m^3/d water (126 bwpd), 95% water cut to 2.6 m^3/d oil (16 bopd) + 17 m^3/d (107 bwpd), 88% water cut. In total, the ISMRA™ increased oil production in the ISMRA™ well and offsets from an average of 4.8 m^3/day oil (40 bopd) to 10.6 m^3/day oil (89 bopd). A pilot application is currently underway and indications are that the offset producers are responding positively to injector treatments. See Figure 4.

6. Applying MEOR can reduce reservoir souring. In March 2009 MEOR treatments began in the Upper Topanga Reservoir, offshore California. Injector E 20S was treated with nutrients on March 5, 2009, December 29, 2009 and January 25, 2010. In addition to seeing an increase in oil production in the front line offsets to injector E 20S, it is noted that the produced hydrogen sulfide concentrations are declining. All but well E 13L show this trend as noted in Table 3. There is no known operational change that has contributed to this reduction. It is believed that the bacteria stimulated with Titan nutrients outcompete the sulfate reducing bacteria (SRB) for nutrients and SRB growth is being depressed.

Table 3. H2S concentrations have declined post treatment.

H_2S Concentration, ppm		
Well	Mar - 09	Aug - 10
E 5L	14,000	9,000
E 10	24,000	20,000
E 11C	20,000	16,000
E 13L	2,200	2,600
E 23	5,000	3,500

7. An oil response is not always seen when treating producing wells. As seen in Table 1 seven of thirty-five producing wells did not show any oil increase after being treated, although all seven showed good bacterial response as a result of the treatments. Six of these are ISMRA™ wells and one is a producer treatment following a successful ISMRA™. Table 4 shows various reservoir parameters for five of the wells treated.

Table 4. Parameters for reservoirs where bacteria responded, but no incremental oil was measured.

RESERVOIR	Upper Shaunavon	Pliocene Sandstone	Mannville	Mannville C	Mannville B
Oil Gravity, °API	22-24	21-24	22.2	15.5-21	15.5-21
Depth, Meters (feet)	1,200 (3,927)	366 (1,200)	1,024 (3,360)	957 (3,140)	945 (3,100)
Temperature, °C (°F)	47 (117)	49 (120)	35 (95)	31 (88)	31 (88)

Pay Thickness, meters (feet)	3.4 (14)	285 (934)	6 (20)	6.3 (20)	8.5 (28)
Permeability, md	567	850	400	1,100	1,500
Porosity, %	15-21	18-33	24	24	22
Salinity, ppm TDS	10,025	16,000	15,500	15,500	7,000
Cumulative Recovery, % OOIP	29	36	18	18	31
Current Water Cut, %	95	98	94	94	99

No correlations between reservoir parameters and unsuccessful applications have been identified. In fact, in comparing the parameters of this table to the parameters of successful applications in Table 2, it is difficult to see much difference. The mystery as to why no incremental oil is seen widens when looking deeper into the applications. For instance, the Upper Shaunovan reservoir had three successful producer applications, the original ISMRA™ and two additional producers (Town, K. 2010). Why this fourth application did not see any incremental oil is perplexing. The answer may lie in the degree of residual oil remaining in the portion of the formation receiving the nutrient materials—in short, very little oil present yields very little opportunity for increased production in such a producing well. Recent work has shown that residual oil saturation in water swept areas can be less than fifteen percent (Romero, C. 2010).

The last two Mannville reservoirs are in different pools in the same field. This field consists of four separate pools. An ISMRA™ was conducted in each of the four pools. Two of the ISMRAs showed incremental oil; two of the ISMRAs did not. Before treatment one of the successful ISMRA™ wells was producing about 1.25 m^3/d (7.9 bopd) + 16.9 m^3/d (106 bwpd), 93% water cut. After peaking at 4.4 m^3/d (27.7 bopd) + 13.8 m^3/d (87 bwpd), 76% water cut, the well tests averaged 2.9 m^3/d (18 bopd) + 19.4 m^3/d (122 bwpd), 87% water cut for the next month after which there were some mechanical issues, before stabilizing at 1.8 m3/d (11.3 bopd) + 13.9 m3/d (87 bwpd), 89% water cut. It is estimated that this single treatment yielded 167 m^3 (1,050 barrels) of incremental oil. Before treatment, one of the unsuccessful ISMRA™ wells was producing about 0.78 m^3/d (4.9 bopd) + 41.3 m^3/d (260 bwpd), 98% water cut. Post treatment production dropped to an average of 0.31 m^3/d (2 bopd) + 24.1 m^3/d (152 bwpd), 98% water cut for the next two and a half months after which production recovered to pre-treatment volumes for the next three months, before eventually stabilizing at 0.4 m^3/d (2.5 bopd) + 40 m^3/d (252 bwpd), 99% water cut. See Figures 5 and 6.

It is worth mentioning that both of the ISMRA™ wells showing no incremental oil were in pools that had previously been under a tertiary alkaline polymer (AP) flood EOR scheme that ended five years prior to the nutrient treatments. Although the AP flood definitely increased the pH of the pool during inception, it was thought that pH would have been stabilized back to pre-flood levels by the time of the MEOR ISMRA™ testing in May 2010. A direct correlation has not been proven between the lack of incremental oil success and the incremental and residual effects the AP flood have had on the reservoir, but it may be worth monitoring in similar future MEOR ISMRA™ trials.

In all seven applications the bacteria responded as expected and as needed for oil release. It is believed that oil must not be in the presence of the activated bacteria. No oil is being released because the area that is being treated is swept of any movable oil.

CONCLUSIONS

Over one hundred MEOR applications have demonstrated that MEOR can be successful in a variety of reservoirs with a new approach to organic oil recovery. Reservoirs with oil gravities between 16° API and 41° API have been successfully treated and yielded significant improvement in oil production rate. Positive results have also been proven in higher temperature and higher salinity reservoirs and such reservoirs should still be considered for stimulation if other reservoir parameters are moderate. Even dual porosity systems should be considered as potential candidates for MEOR based on limited experience over the past four years. In addition to recovering incremental oil, side benefits include reduced H_2S levels. Knowing that there is essentially no risk of damaging the reservoir, there is little downside to trying MEOR as long as due consideration is given to the microbial composition and other reservoir screening parameters. Rigorous scientific analysis prior to treatment is a requirement before initiating an organic oil recovery treatment to optimize potential benefits. MEOR must be targeted and customized to each reservoir. When applied systematically, MEOR can yield significant production and oil recovery increases. It will be interesting to see what will be learned from the next one hundred applications as the limiting constraints are expanded and new avenues explored. Application of organic oil recovery has been shown to be most applicable in secondary recovery projects using water injection since existing infrastructure can be used as the delivery system and avoid any significant new capital equipment expenditure requirements.

ACKNOWLEDGEMENTS
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Figure 1. Devonian producer with 41° API oil shows positive results.

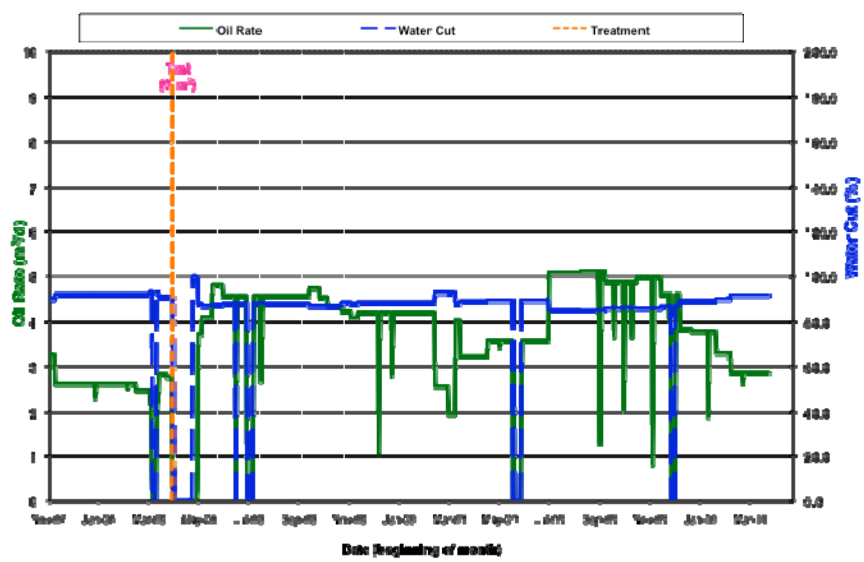

Figure 2. Sparky producer with 16° API oil shows positive response to treatment performed on August 10 2010.

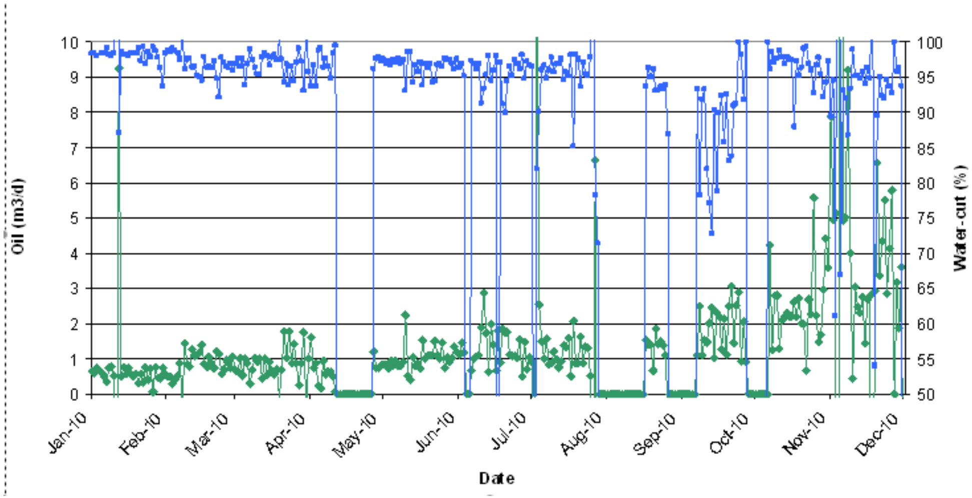

Figure 3. Upper Topanga producer with 16° API oil showing response from treating injectors

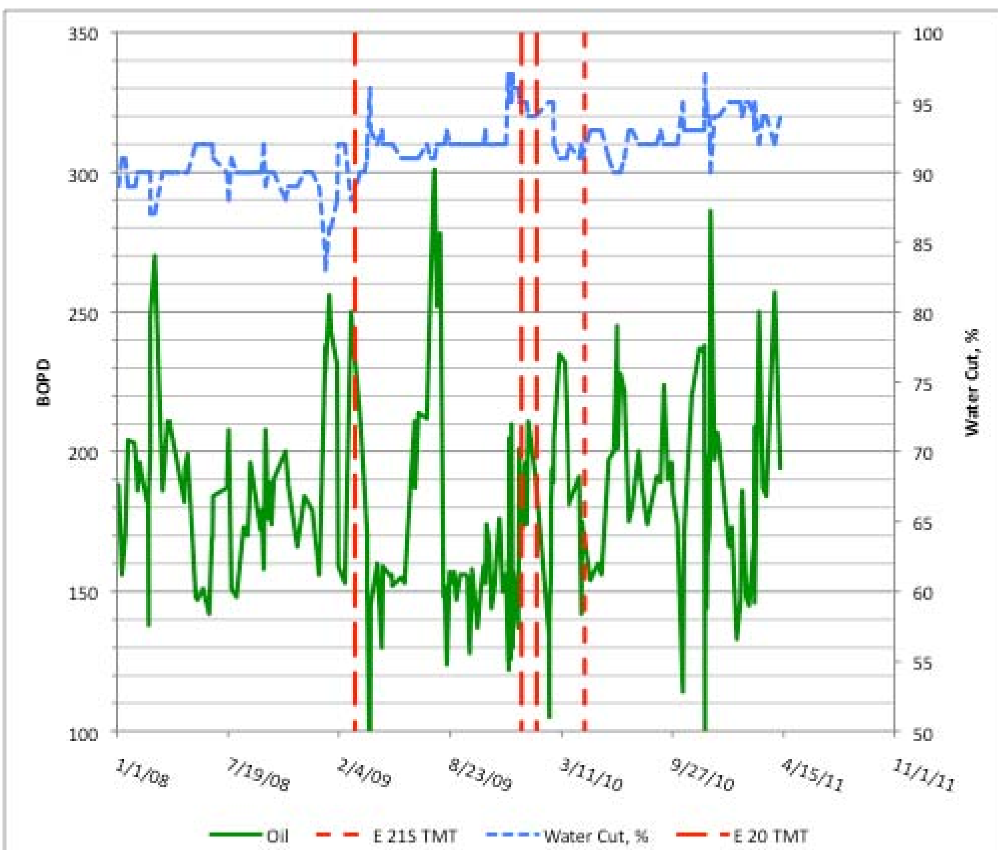

Figure 4. Twelve responding wells of 26-well pilot in dual-porosity reservoir showing positive results.

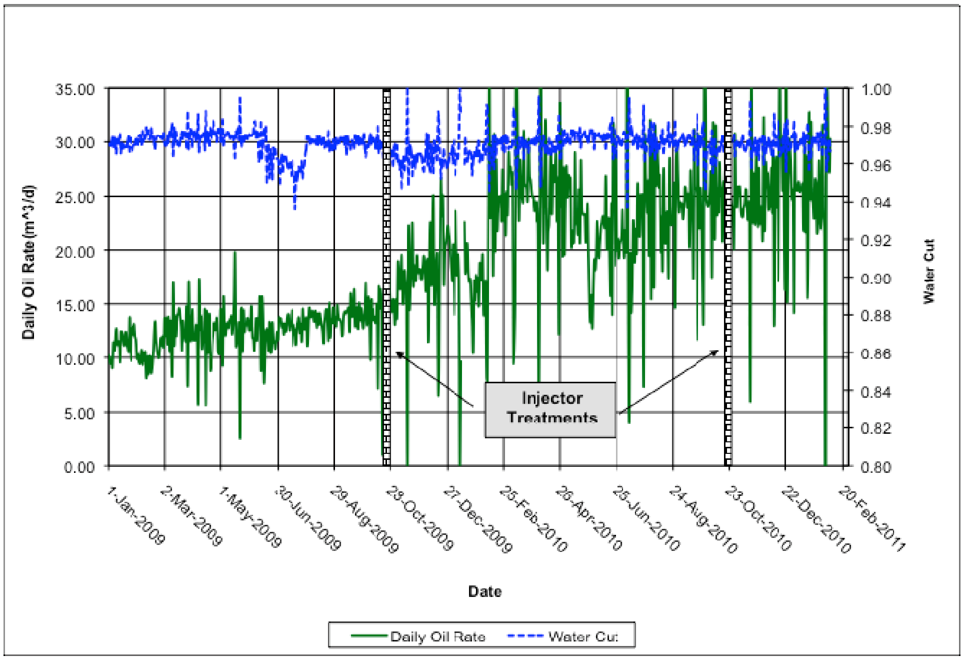

Figure 5. Mannville ISMRA™ shows positive results.

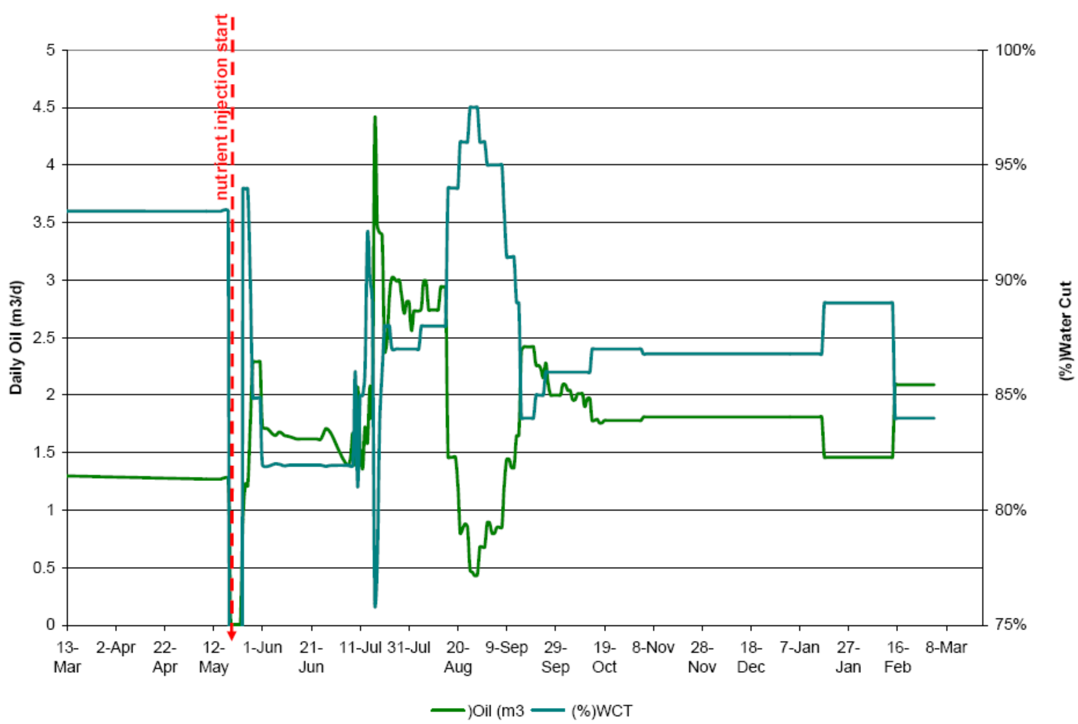

Figure 6. Mannville ISMRA™ shows unsuccessful results.