C O N F I D E N T I A L

Titan Field Applications Supplement

(as of May 16, 2010)

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TITAN TREATMENT SUMMARY

(Unspecified well identification based on Peak Results)

Country/State	Percent Increase	Comment	Project	Comment
California	550%		1	ISMRA*
California	24%	Short term increase	1	Producer
California	32%		1	Producer
California	45% 6 offsets		1	Field
California	900%	Idle Well	1	Producer
California Offshore	47%	Short term increase	2	ISMRA
California Offshore	7%		2	Pilot
California Offshore	0%	Pending	2	Expansion
California Offshore	0%	Pending	2	Expansion
California Offshore	0%		3	ISMRA
Canada	225%		4	ISMRA
Canada	850%	Idle Well	4	Producer
Canada	0%		4	Producer
Canada	525%		4	Producer
Canada	261%		4	Pilot
Canada	64%		4	Expansion
Canada	27%		4	Expansion
Canada	0%	Pending	4	Expansion
Canada	0%	Pending	4	Expansion
Canada	387%		5	ISMRA
Canada	46%		5	9-Well Pilot
Canada	1000%		6	ISMRA
Canada	54%		6	Pilot
Canada	100%		7	ISMRA
Canada	44%		7	Pilot
California	0%		8	ISMRA
Canada	36%		9	ISMRA
Canada	64%	Short term	10	ISMRA
Canada	7%		11	ISMRA
Canada	0%		12	ISMRA
Canada	0%	Pending	13	4 ISMRAs
Canada	0%	Pending	14	8 Producers

* ISMRA: In Situ Microbial Response Application. This is a simple and low cost test to see if the microbes are responding in the oil field as expected (similiar to the responses in the lab).

CURRENT APPLICATION SUMMARY TOTALS

30 Applications

61 Individual Well Treatments

21 Production increases (five pending)

Application
Success Ratio: 21/25 84% (based on completed applications, excludes pending results)
21/30 70% (based on number of applications)
17/30 57% (excluding short-term benefits)

Treatment
Success Ratio: 47/61 77% (based on number of individual treatments)
44/61 72% (excluding short-term benefits)

HISTORIC RESEARCH AND DEVELOPMENT FIELD APPLICATIONS

Below are brief summaries of the five fields treated during the research and development phase of the Titan Process and the commercial field applications that followed.

FIELD APPLICATION SUMMARIES

Research and Development Phase

Alton Field—Queensland, Australia—January 1989

Results reported in SPE/DOE 20254

Highlights:

- Increased production was sustained from a single treatment
- 40% increase in production for 12 months
- Producing water cut decreased
- Production was more stable after treatment
- Indications of changed flow patterns within the reservoir pore space

After successful lab research and formulation of the Titan Process technology and protocols, the first field trial of the Titan Process conducted on a small field in Australia located in the Surat Basin, Queensland. The application of MEOR in this field resulted in a substantial and sustained increase in production compared to control operations on the same reservoir. Increased production was sustained from a single treatment. Twelve months after the treatment, an approximate 40% increase in net oil production continued. The test was unique at that time in that stringent controls were applied during the assessment.

The Alton Field produces from the Lower Jurassic, Boxvale Sandstone. The field was formed by a combination of structural and stratigraphic traps with anticlinal closure controlled by permeability barriers and edge-water contacts. Reservoir temperature is 169 deg F (at the upper end of microbial treatments). Individual sands in the Alton Field are thin with permeabilities from 11 to 884 md (average of 260 md) and porosity averaging 17.2%. Original-oil-in-place has been estimated between 6.6 million and 13.6 million STB. The oil is medium light and residual oil at the time of treatment was about 50% of original-oil-in-place. The field's drive mechanism was a weak water drive and fluid expansion.

The field commenced production in 1969 at about 1,000 bopd and followed an exponential decline. Low primary recovery and high residual oil saturation made the field and excellent trial location. MEOR was considered to provide a combined mechanism that included: (i) profile improvement on aquifer movement and sweep, and (ii) some potential surfactant characteristics of microbe stimulation. The treatment was conducted by injection of nutrients into a single producing well.

Two control studies were done prior to injection of the nutrients. The first was a trial shut-in period to understand the impact of pressure build-up due solely to stopping production. The second control included the injection of produced water, followed by a shut-in period to simulate actual treatment volume and conditions. The actual treatment was compared to these two control operations. A total of 86 barrels of nutrients were injected after filtering them through 28 and 10 micron filters. The well was shut-in for incubation for 21 days.

The results were very good. Production was up roughly 40% from the control case, water cut decreased and production was less erratic than the control case. Chemical analysis of produced water was indicative based on concentrations of marker anions and cations of a release of connate water. Post stimulation microbe concentrations were up nearly a hundred-fold. No changes occurred to the composition or physical characteristics of the oil and no plugging or H2S concentrations (no sulfate reducing bacteria) were stimulated.

Rankin Field—Texas, USA—July 1990

Highlights:

- Pre-treatment, the field was declining at 19% annually
- This was a first treatment on water injection wells
- Two treatments were performed
- Pre-treatment, the field was producing 40 bopd
- The Titan Process resulted in a 60% increase in production
- Overall field production decline was halted for two years
- Public production records indicate production held above base rates for an additional two years

In July of 1990, the Rankin Field in Harris County Texas was purchased for the purpose of conducting field tests with the Titan Process. Since the field was purchased for this purpose, strict attention was given to holding the entire field operations constant, so the only change would be the MEOR treatment. All other potential treatments or operational enhancements were eliminated.

The Rankin Field was discovered in the early 1950s and had been under an active water flood since the mid-l960s. A carbon dioxide tertiary recovery project had been attempted in the mid-l980s, but had been discontinued as an economic failure shortly thereafter. In 1987, due to depressed oil prices, about fifteen of the field's twenty wells had been shut-in leaving two active producers and three active water injection wells. The field was producing approximately 40 barrels of oil per day on a 19% annual exponential decline.

Two MEOR treatments utilizing the Titan Process were performed in July, 1990 and January, 1991. The microbial treatment had an immediate positive effect on the Rankin

Field. Oil production increased, water injection pressures increased and the overall field decline was halted. Although only two treatments were performed, over two years approximately 24,400 barrels of additional oil were produced over the established and expected production performance (pre-treatment).

Of particular importance on the Rankin test was the treatment of the waterflood injection wells. This was the first application of the Titan Process to an existing water injection project with the intention of affecting the adjacent producing wells. Injection pressures on the injection wells gradually increased after treatment, from roughly 400 psi to approximately 1100 psi. As might be expected, the initial concern was that the wells had plugged-off as a result of the treatment as often happens with polymers and other plugging agents. However, upon shutting-in the injection wells, pressure fall-off indicated the wells were indeed open and the three injection wells decreased to zero pressure within three to five minutes. This behavior provided verification that selective permeability alteration had occurred in the reservoir creating a subsequent re-profiling of the injection sweep—exactly the desired response. The adjacent producing well behavior confirmed the effect on production. The field test was concluded in the later part of 1992 with more than 18 months of documented production performance under controlled circumstances. Public production records indicate the treatment production held until the end of 1994 (without further treatment). After that, production declined but the field life appears to have been extended for about five and a half years.

Following the controlled field test, the field was sold to another operator.

Note: the field contract petroleum engineer at the time of the test had been on a previous microbial job (not the Titan Process) in Oklahoma in 1983 where the two-well treatment had failed and there was an increase in corrosion in one of the wells (a significant negative). The engineer entered the Titan test as a “cynical skeptic”. His summary comment after the Titan treatment was that it was an extraordinary success,

Beatrice Field—UK Sector, North Sea—1991-1995

Highlights:

- Before treatment, the field was mature and rapidly declining
- Overall production increased 25% over the baseline (multiple operator improvements including the Titan Process)
- Significant water-oil-ratio improvements were observed in producing wells adjacent to the treated injection wells
- Production decline on key producing wells was altered positively and significantly following the treatments
- Injection rates declined and pressures increased, indicating a likely re-profiling of the water flood sweep pattern (a positive outcome)

The Beatrice Field is located in the inner Moray Firth in the United Kingdom some *35* kilometers offshore of Scotland. The field was discovered in September, 1976 and began production in September, 1981. Peak production of more than 50,000 bopd was reached in 1985. Oil reservoirs are at an average depth of 5,898 feet and the Beatrice platforms

(three steel production structures) are installed in 148 feet of water. Oil is high quality at 39 degree API with high wax content (17%). The Beatrice Field oil is believed to be sourced differently than the bulk of the North Sea fields and produces from lower to middle Jurassic reservoirs. At the time of the microbial treatments, the field was operated by British Petroleum. However, the field was sold to Talisman at the end of the treatment cycles following improved production performance.

At the time of treatment, the Beatrice Field was a mature and rapidly declining oil resource. The Titan Process was applied beginning in late 1991 and continued until the latter part of 1995 with eleven treatment cycles. British Petroleum carefully reviewed the microbial process before it implemented the treatment at the Beatrice Field. All treatments were performed on Platform "A" (the Alpha platform). The field is a complex, multilayered reservoir with average porosity of 16% and permeabilities ranging up to 6 darcies in cores. As an example of reservoir quality, well A-08 was producing 460 bopd at 93.7% water cut. Water saturation ranged by sand from 15% to 60% and permeability averaged 170 md with zones up to 600 md. Water injection rates on the eight Alpha injection wells ranged from just under 5,000 bwpd to over 21,600 bwpd. Injection rates were restricted during treatment with the Titan Process. Initial treatments were on single producing wells at one time (A-l4 and A-08), but end-treatments included up to seven wells (all injectors) at a time. In total eight injectors were treated.

The Beatrice Field is a complex oil field and British Petroleum was experimenting with a number of processes and techniques to improve production as part of their mature assets service team (MAST). These efforts included improved reservoir management, increased pump run times, improved well operations and the use of the Titan Process.

In July of 1996, British Petroleum acknowledged an overall increase in production of approximately *25%* over previously established baseline. An independent consulting firm was contracted to evaluate overall performance enhancements (Bridgefield Consultants Ltd.). There were three key outcomes of this review.

First, the recognized improvement in water oil ratios in the producing wells adjacent to the treated water injection wells was significant. This was an expected outcome of our MEOR process and could not be attributed to the other operational production improvements.

Second, production declines on key producing wells were noticeably altered in a positive way within months after the MEOR treatments were begun.

Third, injection rates declined, indicating the likely re-profiling of the injection sweep pattern—again, an expected and predictable outcome of the microbial process.

While the absolute benefit of the treatments is confused by other ongoing work, BP continued to apply the Titan Process for four years and an incremental production contract was issued in March of 1994 and incremental production payments were made over the following 20-months through November, 1995—in our minds, a notable success.

Kuparuk River Field—Alaska, USA—November 1996

Highlights:

- Well B-20 production increased within two weeks by 100%
- An unexplained increase in well E-08 from 750 bopd to 1300 bopd with a dramatic change in water cut. There was no other explanation (other than the Titan Process) according to the field operator.

The Milne Point Field, located at Milne Point on the North Slope of Alaska's Prudhoe Bay, was treated in November of 1996. The field lies to the west of the Prudhoe Bay Field and is an extension of the Kuparuk River Field. In general, Milne Point produces from the Schrader Bluff formation of the Late Cretaceous. The general area production history (Milne Point and Kuparuk River) provides evidence of sealing or baffling faults. Some faults separate pressure cells, offset fault blocks with distinct oil-water contacts, and create barriers to enhanced oil recovery. At some sites, producing wells receive no support from adjacent injectors—all making definitive interpretation difficult.

The Kuparuk Top C sand was the target of the treatment. At the time of the treatment, there were two active injectors (B-14 and CFP-2). There were three active producers (B-l 5, B-20 and E-8). At the commencement of the treatment, wells B-is and B-20 were producing only water at a rate of approximately 6,180 bwpd and well E-08 was producing 750 bopd and 1300 bwpd at 43% water cut. However, some data indicate that well B-20 was producing intermittently from 10-100 bopd. Both Kuparuk and Milne Point are heavier oil than the nearby Prudhoe Bay field at 23 deg API and 19 deg API, respectively. At the time, communication between the injectors and wells B-lS and E-08 was uncertain due to reservoir faulting.

The Titan Process was applied to water injection well B-14 on November 1, 1995. The injection rate of the injectors for wells B-14 and B-20 each was approximately 6700 bwpd, but there was no differentiation between the two wells. Well B-14 was slowed for the nutrients to be injected. Shortly after the treatment, construction work required the three producers to be shut-down, and injection was reduced. Prior to the shut-down, well B-20 production was up more than a 100 bopd to 200 bopd after only about two weeks from the injection treatment. While the response time would have been very fast, the operator could not find any other change in operating conditions that would have accounted for the change.

A most curious behavior occurred in well E-08 immediately following the treatment on well B- 14. The rate very suddenly jumped from 750 bopd at 43% water cut to over 1300 bopd at less than 20% water cut. Conventional wisdom would say that such a change was unreasonable, but there was no other explanation--just as with well B-20. The effects were still being seen two months after the treatment.

Milne Point displayed the two changes often seen with this process. First, a rapid change in production often associated with decreased water cut and then a delayed impact about 4-6 weeks later. These effects have been seen on several treatments.

This behavior could be indicative of microbial actions removed from the injection wellbore rather than near wellbore. The effect was quite marked, and its origins remain unexplained, but a distinct change in reservoir behavior occurred.

Springfield North Field—Indiana, USA—December 2004

Highlights:

- One injector and five adjacent test pattern wells were targeted
- Overall, average production from well tests increased 18.9% over a six month post-treatment period
- Six months after the last treatment, the test pattern wells have increased an average of 69.5% (the highest individual well increase was 116%)
- Water injection rates reduced 19.7% and pressure increased by *9.5%*, indicating water injection profile changes.

The Springfield North Field was a carefully planned test of the Titan Process. Pre-treatment methodologies were developed with the oil industry consultancy firm of Ryder Scott Company, who suggested a small field trial as the physics in a small field are exactly the same as in a large field. The trial lasted 15 months, with a controlled 9-month baseline period and a 6-month post treatment evaluation period. Before and after results of the five individual producing wells and performance of the single treatment (injection well No. 14) well are critical to the evaluation. The test area exhibited the highest quality reservoir and rock qualities as determined by Ryder Scott.

Springfield North produces from the Palestine sandstone formation (primary treatment target) and the McCloskey limestone in Posey County, Indiana. The field was discovered in 1946, with estimated original-oil-in-place of 5.13 million barrels in the Palestine. The field has been under waterflood since the early 1950s. The primary drive mechanism was solution gas with a limited natural water drive. Primary production was 24.1% and secondary recovery was good at 26.6%. A total of 54 wells were drilled in the field and at the time of the test, 30 wells remained active. The test pattern included five producing wells, one injector and two non-pattern wells. All Palestine wells are completed “open-hole” at a depth of about 1900 feet. The Palestine formation is a thin sand reservoir (8-10 feet) in this location with good porosity (19.3%), good permeability (362 md) and bottomhole temperature of 90 deg. F.

The Titan Process was applied to a single injector (well No. 14) in December, 2004 following an extended control period. Test monitoring ended in June, 2005. Well test results were averaged over the 6 months following treatment as compared to the 9-month control period prior to testing. Production from the test pattern well averaged 11 bopd before the test and increased to an average of 19 bopd post-treatment for an increase of 69.5% from December to June. Production increased over the six-month period and the overall period average was 18.9%. The oil percentage in the production stream increased by an average of 28.8% over the six month post-treatment period (albeit still very high water cut, i.e., more than 98% overall). Water volume in the injection well decreased significantly (-19.7%) with an associated increase in injection pressure (+9.5%),

indicating a desired re-profiling of the sweep pattern and improving the injection efficiency.

In June, 2005, while overall production rates were low, well No. 21 was up 116%, well No. 19 was up 73.8%, well No. 4 was up 51.8%, well No. 12 was up 29.4% and well No. *5* was up the least at 6.7%. Control wells outside the test pattern declined on average by 2.1%, although one well outside the immediate pattern also inexplicably increased. Whether it could have been affected by the injection well treatment is unknown. However, overall, the production increases on a percentage basis were good and the possibility and of external impacts was very well controlled.

CURRENT FIELD APPLICATION SUMMARIES

Commercial Operations Phase

Most of the commercial field operations currently underway are covered by confidentiality and non-disclosure agreements with the field operators and owners. Consequently, the following summaries have been written without specific references to companies, field names or well designations as required by the confidentiality agreements. Two fields can be identified and have been disclosed by the operators as a result of two Society of Petroleum Engineers publications documenting the field success. Specifics are given below.

California Oil Field—Los Angeles Basin—2007-ongoing

Results reported in SPE #129742: MEOR Success in Southern California

Highlights:

- A total of twelve (12) treatments have been completed
- A single-producing well ISMRA test resulted in a peak production increase of *550%* and a sustained 265+% increase in production rate from 20 bopd to 73 bopd over three months
- Three injection wells were each treated with three cycles over a seven-month period
- Five adjacent first-line producing wells were monitored for response (but not directly treated). Microbe response within the reservoir was excellent and production on these wells increased by 53 bopd over a 179 bopd baseline production—a 39.6% increase and a 6% total field improvement
- One idle, non-producing well was returned to production and increased from 0 bopd to a peak of 46 bopd bringing new life to a dead well

An application of the Titan Process on a California oilfield in the Los Angeles Basin resulted in an average 265% production increase over a three-month period beginning in mid-2007. From a base production rate of approximately 20 barrels of oil per day, the

post-treatment rates went to 110 barrels of oil per day (a 550% increase), and averaged 73 barrels per day over the first three months. This single producing well application was well above expectations.

The percent water produced (water cut) also decreased significantly, which was an additional benefit of the treatment. Since the initial treatment, the application has been expanded to a full-field treatment by performing an additional nine water injection well treatments and two additional producing well treatments. Based on both biological indicators and production data, the field seems to be showing a positive response to the injection well treatments.

Geologically, the field has three major producing horizons, with the shallowest being of Pliocene age and the deeper (more productive) zones being of high quality Miocene sands. The sand layers are noted as the Wolfskill, the Hauser and the Ogden. The Hauser zone is the most extensive of the zones and is the most productive. It is also the target of a current waterflood project. The field is a tightly folded anticline with faults forming the boundaries of the field. The field has experienced a fairly well documented decline over the past several years prior to application of the Titan Process.

Titan engineers worked closely with field operations personnel to develop a step-by-step approach to field treating. During July, 2007, a small volume of Titan's proprietary nutrients was injected into a single producing well to check the reaction and behavior of in-situ microbes in the oil-producing reservoir (ISMRA). The nutrient concentrate was mixed with 100 barrels of produced water and displaced with 350 barrels of injection water. The well was then shut-in for three days to allow specific indigenous microbes to grow and multiply as a result of nutrient stimulation. Following the extraordinary performance of this initial application, the field operator chose to expand the project to the full field by treating the field's three water injection wells with three treatment cycles each, for a total of nine treatments, over a seven-month period from November, 2007 to May, 2008. Adjacent producers have been positively affected, with a combined current production increase from five wells of over 30 barrels of oil per day—an overall production increase of about 6% of total field production. At one period of time from July through October, 2008, the first line of producing wells was making over 50 barrels of oil per day over the previously projected decline rate (by operator engineers)—a 30% increase.

Of particular note, one well in the field (also a first line well) had been shut down and kept idle from May, 2004 until mid-June, 2008 when Titan requested the well be put back on production with the expectation that the injection well treatments having a positive response on this portion of the field. After the long shutdown period, the well produced 100% water with no oil until November, 2008. The well "suddenly" began producing oil and eventually peaked at 46 bopd (a 900% increase), although part of this production is coming from a second producing interval. This aspect of the treatment raises the possibility that idle (non-producing) wells may be stimulated with the Titan Process, giving them new life and new profitability.

Two producing wells (in addition to the ISMRA) were also treated in the same field. While the treatments went well from an operational perspective, these two wells have not

seen the same magnitude of benefit as other treatments in the field. One well is making a small amount of incremental oil, but the other seems to be unchanged despite a very good microbial response. Titan engineers are working with the operator (owner) to determine possible reasons for the result when considering the microbial response was good. These wells have identified some areas requiring further study in applying the Titan Process to producing wells.

This field owner has conducted an ISMRA on one reservoir and an ISMRA and a pilot on another reservoir in another field in offshore California (detailed separately) and has sampled three reservoirs in a third field in Texas for possible Titan Process application.

Saskatchewan Oil Field—Saskatchewan, Canada—2007-ongoing

Results reported in SPE #124319: MEOR Success in Southern Saskatchewan

Highlights:

- A total of thirteen (13) treatments have been completed
- A single producing well was treated with an ISMRA test. Peak production increased 225% from 8 bopd to 26 bopd. Producing water volume decreased by 15%
- The ISMRA well continues to produce well above baseline more than twenty months following treatment
- A pilot was performed on a single injection well to monitor behavior of three adjacent producing wells
- The injection well has now been treated with three separate cycles
- Production in the pilot area increased from 23 bopd to a peak of 83 bopd, a 261% increase
- Three additional producing well treatments have been performed and an additional injection well has been treated to expand the pilot area
- An idle, non-producing well was returned to production and treated with Titan nutrients on two occasions. Following the second treatment, production increased from 2 bopd to 19 bopd—an 850% increase
- Field application has been initiated by treating two more injectors

    - One injector has had three treatments and production from the offset producers has increased from 64 bopd to a peak of 105 bopd after the second treatment. Results are pending on the third treatment, which was performed in November, 2009.

    - The other injector has had two treatments. After the first treatment, production increased from 52 bopd to a peak of 66 bopd in its offset producers. Results are pending on the third treatment, which was performed in November, 2009.

An oil field owned by a major Canadian oil company was treated in Saskatchewan, Canada beginning in December of 2007. Since that time, a total of five producing well

and 8 injection well treatments have been performed for the owner. With one exception, the producing wells have responded extremely favorably and the injection response has been outstanding. The operator is now expanding use of the Titan Process within the initial field and in four additional fields in another Canadian province.

The treated reservoir is Middle Jurassic sandstone in three identifiable “lobes”, or members, ranging from very high quality sand and excellent reservoir character in the upper member to a tight mixture of sands and shales in the lower member. Average porosity ranges from 21.4% to 15.2% in the poorer quality portions. Average permeability (a measure of the reservoirs ability to flow oil) ranges from 600 md to 50 md. This reservoir is a relatively thin sandstone formation with a total thickness of less than 20 feet. The field has been waterflooded for many years and overall recovery to date is approximately 25-35% of the original-oil-in-place. While the oil gravity is heavier than Titan initially targeted, the characteristic of the field proved to be quite suitable and the field response has been excellent.

The initial ISMRA test, a single producing well treatment, resulted in an excellent microbial response in the reservoir and a resultant increase in production. The well was originally treated in early December, 2007. Approximately, three weeks after the treatment, a “step-change” in production occurred, with the rate increasing from 8 bopd to 26 bopd—a 225% increase in the well’s production. Of major significance is the fact that the increase (144% increase in production) was still evident more than one year after the single treatment. Overall produced water volume has decreased approximately 15%.

Based on the positive results of the ISMRA, a pilot treatment on a single water injection well was then initiated by the field owner**.** To date, three treatments have been performed on the single injection well between April and December, 2008. The closest producing well has had a remarkable response, with an increase in production from 18 bopd to 51 bopd —a 183 % improvement. The well has shown an incremental production improvement with each treatment cycle so far. A second production well (more distant) has also shown an increase from 9 bopd to slightly over 12 bopd—a 34% increase. A third well in the injection pattern (the most distant and lowest volume) has yet to show an increase and the well is currently shut down due to mechanical problems not yet addressed by the operator.

The operator has expanded the application to two more injectors. After two treatments, one injector and its offset production had an increase from 64 bopd to 105 bopd, a 64% increase. The other injector after one treatment had an increase in production from 52 bopd to 66 bopd, a 25% increase. Both injectors had an additional treatment in November, 2009. Results of the latest treatments are pending. In addition, the operator has ordered initial treatments on two more injectors.

Three additional producing wells have been treated between April and December, 2008. The latest treatment in early December saw an increase from 4 bopd to 25 bopd, a *525%* increase. The previous two treatments were interesting in that one has been something of an enigma due to its lack of response and the second, a well that had been shut down for a number of years as a non-producing well, has been extremely successful and opens an important avenue of application for the Titan Process.

The first well had an excellent initial microbial response and demonstrated a prolonged response with hydrocarbon interacting species—but no significant associated production increase. The production for this well was on a very significant decline prior to the treatment and, after eight months, the well is essentially producing on the decline trend even though recent production has increased somewhat and might be indicative of some incremental oil production, albeit small.

The second well is quite significant in that the treatment was performed on a well that had been shut down due to uneconomic production. The well was treated at the suggestion of the owner as an experimental process to determine if such a well could be given new economic life. The well was returned to production February, 2008 to establish a baseline production level. The Titan Process was applied at the end of April, 2008. The indigenous microbes did not respond as hoped following the treatment and production continued to decline.

Titan scientists re-formulated the nutrient mixture and performed a second treatment at the end of July, 2008. The well saw a typical "step-change" in production at the end of August, 2008 based on the second treatment. Production increased from 2 bopd to 19 bopd—an 850% increase.

The field operator has expanded Titan treatments to four other fields in Alberta, Canada and one in Saskatchewan. Two adjacent Alberta fields are substantially bigger than the initial field application, with combined production of approximately 7,000 bopd. In addition, sampling and lab work has been completed on one field, lab work is in progress on samples taken from yet another field and planning is in progress for sampling a third Saskatchewan field. Titan is now involved in nine fields with this operator as success continues.

Alberta Oil Field #1—Alberta, Canada—2008-ongoing

Highlights:

- A total of four (4) treatments have been completed
- A single producing well was treated with an ISMRA test. Peak production showed a 100% increase in oil production from 16 bopd to 32 bopd
- The percent of water produced with the oil also decreased (a positive result)
- The increased oil production has continued for more than eighteen months. In fact, the well recently hit a second new high of 32 bopd.
- Three treatments have been performed on a pilot water injection well. After a second treatment, the four offset producing wells increased production from a base of 100 bopd to 163 bopd (a 63% increase). Results of the third treatment are still pending
- An ISMRA test has been conducted in a second field and a third field is being tested for future applications of the Titan Process.

Titan applied its process on an oil field in central Alberta, Canada. The field produces from the Gilwood sandstone and is under waterflood as a means of secondary recovery. From samples taken during a field visit, it was found that the oil and water samples did not contain the normal variety of microbes that are generally found and used in applying the Titan Process. However, good concentrations of other indigenous microbes that tended to flourish in the higher salinity environment in the field were found. Titan scientists determined in the laboratory that it was possible to achieve a microbial response with these microbes that had the potential of freeing trapped oil. Titan and the operator agreed to proceed with this higher risk application. Titan's microbiologists subsequently found a nutrient formula that they felt would be successful in this field.

The field had significant original-oil-in-place of approximately 65 million barrels and a cumulative recovery of 23% at a current production rate of 500 bopd from 22 producing wells and 10 water injection wells. Reservoir characteristics were good, with 14-16% porosity, permeability of 300 md, and a depth of roughly 3500 feet resulting in moderate reservoir temperature and pressure. Only the reservoir water was anomalous for the Titan Process, with high salinity of 142,000 parts per million. Crude oil produced is a light high quality crude (API gravity of 41.1 degrees).

In April, 2008 an ISMRA test was performed on a chosen producing well expected to be representative of the broader field characteristics. The mechanical treatment was anomalous to other Titan treatments, in that the nutrient injection pressure was very high and it was not possible to displace the fluids away from the wellbore, as we would normally prefer. It was later determined that there may have been a buildup of asphaltene deposits in the well which led to plugging during the treatment. There was a definite degree of pessimism immediately after the treatment and this was followed by mechanical problems with the well that effectively kept the well shut-in for an extended period of time, leading to an excessive nutrient incubation period of more than three weeks.

Despite these apparent setbacks, following the well's return to production, an increase in production of 87% from 16 bopd to 30 bopd was experienced and the well recently hit a second peak of 32 bopd, a 100% increase over its pretreatment rate.

Following this successful ISMRA test, a single water injection well has been treated three times as a pilot project in the field. After two treatments, production peaked at 163 bopd, 63 bopd over its pretrial base for a 63% increase and a 44% increase over its former pretreatment production of 113 bopd.

Titan has worked in two other fields for the operator. One field awaits the initiation of a pilot water flood facility before the Titan Process will be applied and the second field just conducted an ISMRA test. One field **is** located in Alberta and the other is located in British Columbia.

California Offshore Field #1—2008-ongoing

Highlights:

- A total of seven (7) treatments have been completed
- Two single producing well ISMRA tests were performed on this offshore field
- Microbial response was good in one of the two ISMRAs and a pilot water injection well treatment was begun in early 2009
- After a second treatment on the pilot injector, the front line producers are showing an increase of 7% to 168 bopd. A third injection treatment completed in January, 2010
- The other ISMRA producing well has had three treatments and results are pending on the last treatment

Following field screening and well-fluid sampling, this field was treated with two **ISMRA applications of the Titan Process.** Two ISMRAs were recommended, since the field has two very distinct producing horizons with very different reservoir characteristics. The field was unique in that one of the producing zones contains 16-18.5 degree API crude (quite heavy by Titan treatment standards) and the crude is "sour"; i.e., containing relatively high concentrations of hydrogen sulfide—normally associated with sulfate reducing bacteria (SRBs). The second (deeper) zone contains lighter sweet crude of 30.6 degree API oil. Titan found the oil and water from both reservoirs contained an excellent variety of microbes that can be used for the Titan Process. However, because of the oil characteristics of the upper zone caused Titan to characterize the treatment as higher risk than our normal applications. However, the fact that the oil has been proven to be quite mobile and has responded well to waterflood operations and the high biological activity, both Titan and the operator chose to proceed with the ISMRA test.

The lower zone provided an additional challenge in that the reservoir has an ongoing treatment for hydrogen sulfate suppression. The chemicals used in the ongoing treatment present a potential conflict with the Titan nutrients, so this was an added and unusual twist for the Titan scientific team. This field contains the most complex microbial ecosystem evaluated so far for the Titan Process.

In this field, the upper reservoir produces over 50% of the oil. The basin floor turbidites are of middle Miocene geologic age. Reservoir characteristics are very good with porosity measurements of 34%, and permeability (ability of the sandstone to produce liquids) is excellent but quite variable in its range of 1.5 md to 2.5 darcies. Reservoir thickness is also variable, ranging from 50 feet to 150 feet (northwest to southeast). There is some variability in the original oil volume calculated by the current and previous owners, but recovery seems to be 25-30% (likely between 40-60 million barrels of original-oil-in-place). Such variability presents certain treating challenges. The primary drive mechanism appears to be gas expansion, formation compaction and, perhaps, a weak natural water drive—but the field is now being waterflooded. The lower zone, also of Miocene age, is also geologically very complex due to its transgressive marine sediments and complex geologic features (faulting and erosional surfaces).

Porosity ranges from 15-22%. As with the upper zone, reservoir thickness is 30 feet in the north and thins to the south—again creating some treating challenges. Original oil volume calculations vary quite dramatically, but it is likely in the range of 10 million barrels of original-oil-in-place.

The upper zone ISMRA test was conducted in early October, 2008. Post-treatment laboratory analysis indicated a large increase in the number of microbes after the well was returned to production. The behavior of the microbes was very much according to plan, but the response was short-lived. Production performance associated with the microbial activity tracked very well. From a pre-treatment rate of 181 bopd, post-treatment production peaked at 266 bopd. The increase was very short in duration and production rapidly returned to its previous rate and decline. Nonetheless, the behavior of the reservoir gave both Titan and the operator encouragement to proceed with a pilot treatment on the water injection system. This work was begun early in 2009 and a second treatment was performed in December, 2009 and a third treatment in January, 2010.

The lower zone ISMRA test was less encouraging due to the lack of post-treatment microbial activity. However, the Titan scientific team believed the lack of response is due to the ongoing hydrogen sulfate suppression treatments and two re-treatments were conducted. Results are pending on the last retreatment in late-December, 2009.

Alberta Fields #2&3—Alberta, Canada—2009-ongoing

Highlights:

- Two single producing well ISMRA tests were performed on two adjacent fields
- Both saw good microbial and production response
- The ISMRA test in one field increased production 387% from 8 bopd to a peak of 39 bopd
- The ISMRA test in the second field increased production 1000% from 2 bopd to a peak of 22 bopd
- Pilot projects are currently being conducted in both fields with a combined ten additional treatments performed in October, 2009
- Preliminary reports indicate that the operator is seeing incremental oil in both pilots

These are adjacent fields in the same reservoir and development is being handled in parallel, since the operator has already seen success in another field. After field screening and well-fluid sampling, each field was treated with an ISMRA application of the Titan Process. The reservoir contains 20 degree API crude (heavy by Titan treatment standards). Titan found the oil and water from both reservoirs contained an excellent variety of microbes that can be used for the Titan Process.

Reservoir characteristics are very good with porosity measurements of 30%, and permeability (ability of the sandstone to produce liquids) is excellent at about 600 md. Reservoir thickness is about 45 feet. Recovery is about 33% (103 million barrels) of oil

originally in place. The primary drive mechanism appears to be gas expansion, but the field is now being waterflooded.

Both ISMRA tests were conducted in January, 2009. The producing well in one field increased production from 8 bopd to 39 bopd, a 387% increase. In the other field, the production well increased production from 2 bopd to 22 bopd, a 1000% increase. In addition, both fields saw adjacent wells respond. Although these wells were not treated, it is believed the nutrient migrated away from the treated producer while the well was shut-in, allowing time for the microbes to respond to the nutrient treatment. In the first field, an adjacent producer doubled its production from 6 bopd to 12 bopd. In the second field, several adjacent wells responded. One adjacent producer increased its production from 2 bopd to 14 bopd, a 600% increase.

Pilot projects were initiated in both fields in October, 2009. On the first field it was decided to do a nine-well pilot. So far, the operator has reported that seven of twenty-two offset producers are showing an increase in oil production. The second field is a single well pilot. It has been verbally reported that production has doubled in each of the four offset producers from 6 bopd to 12 bopd.

Saskatchewan Field #2—Saskatchewan, Canada—2009-ongoing

Highlights:

- The ISMRA test was successful, as production increased from 28 bopd to a peak of 40 bopd, a 43% increase
- The operator is considering a proposal for a pilot project for early 2010

Adjacent to the first Saskatchewan field, this field has similar characteristics. The treated reservoir is sandstone. Average porosity is 26.5%. Permeability ranges from 53 md to 500 md. This reservoir is a relatively thin sandstone formation, with a total thickness of less than 15 feet. The field has been waterflooded for many years and overall recovery to date is approximately 42% of the original-oil-in-place. The oil gravity is 22 to 25 degree API crude.

The initial ISMRA test, a single producing well treatment, resulted in an excellent microbial response in the reservoir and a resultant increase in production. The well was originally treated in November, 2009. Production peaked at 40 bopd from 28 bopd, a 43% increase.

British Columbia Field #1—British Columbia, Canada—2009

Highlights:

- The ISMRA test was successful, as production increased from 17 bopd to a peak of 28 bopd, a 65% increase

The treated reservoir is sandstone. Porosity is from 10 to 15%. Average permeability is 30 md and it ranges from 5 md to 75 md. This reservoir is a thin sandstone formation with a total thickness of less than 7 feet. Although the reservoir has pressure support from bottom water, a single injection well was introduced in February, 2005. The oil gravity is 41 to 42 degree API crude.

The initial ISMRA test, a single producing well treatment, in November, 2009 resulted in an excellent microbial response in the reservoir and a resultant increase in production. Production peaked at 40 bopd from 28 bopd, a 43% increase. Further work is pending additional pressure support needed for sustained incremental production.

NEW FIELD TREATMENTS & OTHER WORK IN PROGRESS

(as of May 28, 2010)

Alberta Oil Field #4:	Results pending for an ISMRA test, which was pumped in December, 2009.
Alberta Oil Field #5:	Results pending for an ISMRA test, which was pumped in January, 2010.
Alberta Oil Field #6:	Sampling and laboratory analysis complete. Field application and ISMRA test pending.
Alberta Oil Field #7:	Sampling complete. Laboratory analysis in progress.
South Texas Field #1:	Sampling and laboratory analysis complete. ISMRA test approval pending.
South Texas Field #2:	Sampling and laboratory results complete. ISMRA test approval pending.
South Texas Field # 3:	Laboratory analysis in progress.
California Onshore #2:	Sampling and laboratory analysis complete. ISMRA test in progress.
California Oil Field #3:	Sampling and laboratory analysis complete.
California Oil Field #4:	Sampling and laboratory analysis complete.
California Oil Field #5:	Sampling and laboratory analysis complete.
California Oil Field #6:	Sampling and laboratory analysis complete.
California Oil Field #7:	Sampling and laboratory analysis complete. ISMRA test approval pending.
California Oil Field #8:	Sampling and laboratory analysis complete.
California Oil Field #9:	Sampling and laboratory analysis complete.
Oklahoma Oil Field #1:	Sampling complete. Laboratory analysis in progress.
Oklahoma Oil Field #2:	Sampling complete. Laboratory analysis in progress.
Australia Oil Field #1:	Final proposal and logistical arrangements are pending.
Brazil Oil Field #1:	Sampling and laboratory analysis complete.
Mexico Oil Field #1:	Sampling and laboratory analysis complete.
Mexico Oil Field #2:	Awaiting approval to proceed with sample.

Indonesia Joint Venture:	Establishment of an Indonesian entity is being evaluated by legal counsel.
Oman Joint Venture:	Sampling complete on Field #1. Laboratory analysis complete and a second field is being chosen for sampling. Field data on two fields being reviewed
German application:	On hold.

HISTORY OF THE TITAN PROCESS

The current Titan Process was first formulated in 1989-90 and originally called the Biological Oil Stimulation (BOS) Process. It was invented by the Carroll brothers and Professor Alan Sheehy.

The Carroll family created and developed with Southampton University an oil water separator called the Vortoil separator in 1980. Within seven years, this invention was in use all over the world and was in wide use on North Sea oil platforms, BWN Vortoil Limited had offices in Australia, U.S., U.K., Saudi Arabia and Singapore. In 1989, Dupont/Conoco bought the Vortoil business for approximately *$35* million. Today the Vortoil technology is an accepted leading technology for offshore oil-water separation. The oil-water separator technology is not directly related to the Titan MEOR process, but the proceeds of the Vortoil sale allowed a $20 million infusion for research and development in what was to become the BOS Process and has now been developed into the Titan Process.

Noel Carroll has had approximately 100 patents issued since he was a teenager. His research into the BOS Process had its beginning with research and scientific inquiry into various microbial phenomena totally unrelated to the petroleum industry in the early 1970s. In the late 1980s, the Carrolls helped finance research on a microbial enhanced oil recovery technology with the Commonwealth Scientific and Industrial Research Organization (CSIRO), Australia's largest government funded research organization. Professor Alan Sheehy, Director and Head of Microbiology at the University of Canberra, was then working with CSIRO and studied the new microbial enhanced oil recovery system extensively. He eventually joined the Carroll team as Research Leader and remains today as Principal Scientist. Professor Sheehy has joined Titan as Vice President and Principal Scientist.

Under Noel Carroll's direction, the group embarked on a new direction in the microbial sciences as it relates to oil recovery. As research continued, laboratory tests and scientific experimentation were successful and culminated in the first field test at a small 40 bopd field in Australia, the Alton Field. The test was successful in 1989. Further Research and Development field trials then followed (See details below).

Titan was incorporated in June, 2001. The Company was founded by Kenneth J. Gerbino to commercialize this oil recovery process. Titan signed a five-year profit sharing agreement with LOSL Services that also included a provision to eventually merge the

two companies, which was recently completed. After forming Titan and organizing the Board, Ryder Scott Company, a highly regarded oil and gas engineering and consulting firm in Houston, Texas was retained to design a test for Mr. Gerbino and his early investors. The test required an independent oil company to try the Titan Process and then, based on these results, Titan would proceed in expanding and commercializing the venture. Another successful field trial was conducted under Mr. Gerbino's direction with the assistance of the consulting firm of Ryder Scott on the Springfield North Field in Indiana.

The next step was for the Company to recruit a management team to expand the scope of the Company and organize it as a viable business. An extended CEO search took almost 12 months. Mr. Brian Marcotte accepted the job in September, 2006.

Since 2006, Mr. Marcotte has been instrumental in bringing the Company to where it is today, with an impressive list of customers and prospects for the Titan Process. In addition, considerable amount of time has been spent on formulating and executing the merger with LOSL. The merger was signed on September 15, 2009 and all documentation and formalities were completed on May 10, 2010 upon filing with the Secretaries of State of both Nevada and Delaware.

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