ELECTROMAGNETIC STIMULATION OF LLOYDMINSTER HEAVY OIL RESERVOIRS: FIELD TEST RESULTS

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Electromagnetic Stimulation of Lloydminster Heavy Oil Reservoirs: Field Test Results

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Abstract

The paper will present the field test results of two electromagnetic (EM) stimulation projects conducted in the Lloydminster heavy oil area. The two wells (A1-11-48-25 W3M Lashburn and A8-6-51-27 W3M Northminster) produce heavy crude from the Sparky formation. Detailed production, electrical and operational data was gathered and analysed to quantify the effect EM stimulation had on each well's producing characteristics.

The main areas covered by the paper include production characteristics (primary and enhanced), in-flow performance relationships (primary and enhanced), operational considerations and some of the related economics. The data discussed to this point has been restricted to reservoir heating.

An additional review of a tubing heating electrical configuration test (ran on the Lashburn well) has been included. The viscous nature of the crude oil being produced caused severe rod fall problems. Tubing heating was initiated to reduce the wellbore fluid viscosity and eliminate the rod fall problem. The paper will conclude with a general overview of the EM stimulation process as applied to the Canada Northwest Energy Limited locations and the potential for future applications.

Introduction

The possibility of using electrical energy to heat oil-bearing formations has been attempted on several occasions over the past four decades. In general terms, the electrical (and electromagnetic) energy is converted to heat. Three basic types of heating are possible (dielectric, inductive and resistive). This discussion will deal with the resistive heating process.

Canada Northwest Energy Limited et al. (CNW) contracted with EOR International (EOR) to field test the process in the Lloydminster area heavy oil formations. A majority of the heavy oil sands around Lloydminster are well suited to the application of electromagnetic (EM) heating. Many of the formations are relatively thin and not well suited for other secondary, tertiary and thermal recovery methods. The EM heating process as applied in the CNW pilot areas creates a heated zone in the near wellbore region. The application of heat significantly reduces the viscosity of the oil, improves the oil/water flow characteristics, and overcomes some forms of formation damage. The end result is an improved pressure profile in the near wellbore region and a corresponding increase in the oil production rate.

Field Evaluations

Introduction

The electromagnetic (EM) heating process was tested in three Canada Northwest Energy Limited project areas (Wildmere, Northminster and Lashburn). The pilot projects (as listed above) were not economically successful (due to premature equipment failure). They did however provide very encouraging technical information from a reservoir engineering point of view. The electrical delivery system used in these projects consisted of externally insulated casing. The casing was electrically isolated from the wellhead and tubulars. The casing insulation was scraped off across from the reservoir to allow EM energy to enter the formation. The energy flow was into the reservoir and up through the overburden to surface ground wells to complete the circuit. The project failures were due to casing insulation failures (Northminster and Lashburn) and/or reservoir specific problems in the case of Wildmere [i.e., sanding, high watercuts and poor permeability (i.e., tight rock)]. The problems encountered to date have since been corrected or can be easily screened for [i.e., use a more competent delivery system (discussed later) and test the process in good reservoir].

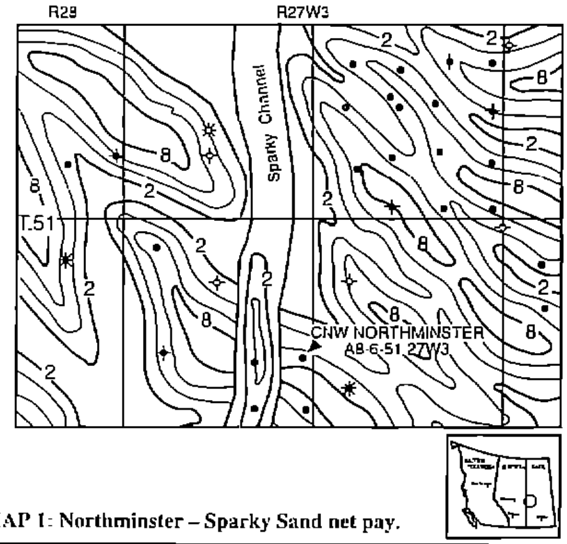
Wildmere, Alberta, Canada
4-30-48-04 W4M, 10-23 and 15-24-48-05 W4M

The Wildmere project (CNW's first) will not be discussed in any detail due to space constraints. Sustained productivity was never achieved because of sanding problems and eventual casing insulation failure. The data obtained was not suitable for analysis from the reservoir engineering viewpoint. The data obtained did indicate a reservoir response was occurring but sanding problems resulted in very short production periods.

Northminster, Saskatchewan, Canada
(A8-6-51-27 W3M)

This field is located six miles north of the city of Lloydminster. The well produces 13.7° API oil from the Sparky formation. The geological interpretation is included as Map 1. The main operating highlights are listed below:

21/03/88 =	Initial primary production
22/04/88 =	GP gas zone communication (well shut-in)
20/05/88 =	Remedial cement squeeze (to shut off the gas zone)
03/01/89 =	Electrical reservoir heating commenced
24/01/89 =	Casing insulation failure
16/05/89 =	Mechanical failure of the casing; electrical heating terminated
29/06/89 =	Resumed production (no heating)



MAP 1: Northminster – Sparky Sand net pay.

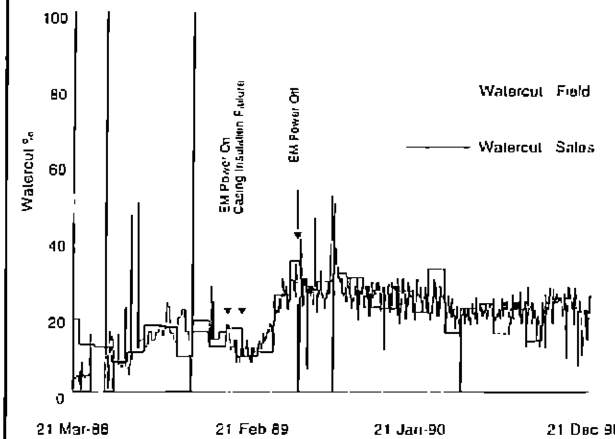


FIGURE 2: EM stimulation: Northminster A8-6 watercut.

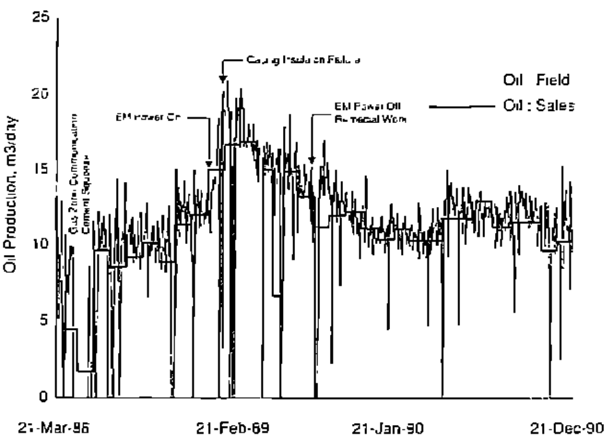


FIGURE 1: EM stimulation: Northminster A8-6 oil production profile (cday).

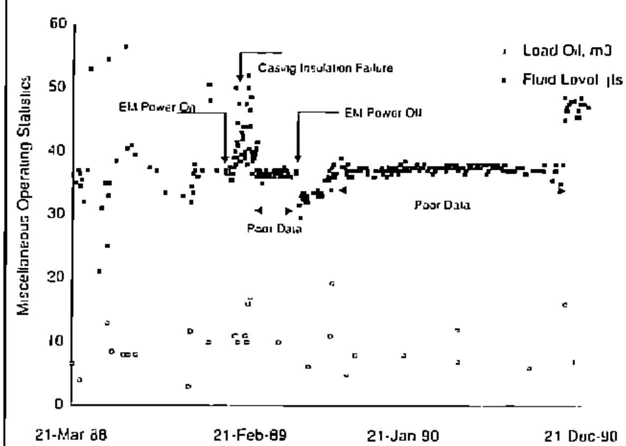


FIGURE 3: EM stimulation: Northminster A8-6 fluid level, load oil.

The primary oil production rate at A8-6 stabilized at approximately 10 and 12 m^3/day (Figure 1) at pump speeds of 1.5 and 1.9 spm, respectively. Water cuts were in the 10 to 20% range (Figure 2). The well's primary production period lasted approximately 10 months.

With the commencement of heating, oil production levels jumped to around 20 m^3/day. It is important to note that a pump speed increase (from 1.9 to 3.0 spm) coincides with the production improvement. As such, a portion of the production increase has to be attributed to the pump speed increase. The productivity index (PI) increased from 0.33 bbls/psi to 0.42 bbls/psi (a stimulation ratio of 1.27). A more detailed discussion of Inflow Performance Relationships is included later to quantify the relative importance of EM heating and pump speed. The production peaked shortly after the casing insulation failed, and has since declined to levels of 11 m^3/day.

Water cuts (Figure 2) responded to EM heating as expected. Under primary conditions, the water cuts rose gradually to 15 - 20%. Once power (heat) was applied to the formation, the water cuts began dropping (expected based on the relative viscosity improvement of oil as compared to water). Once the casing insulation failed, (and the formation had cooled off) the water cut rose rapidly to 30%. The water cut then levelled off around 20 - 25%. The EM heating had a positive effect on water cut and therefore oil production.

Fluid levels (Figure 3) during the primary production phase were generally 35 - 40 joints of tubing from the surface. This corresponds to roughly 150 - 200 m of fluid above the perforations. The well contains 56 joints of tubing. Fluid levels were roughly constant through the first two months of production. Once the pump speed (Figure 4) was increased to 1.5 spm, the fluid levels dropped for one and one half months then gradually began rising (probably due to near wellbore permeability improvements). The fluid level had stabilized over the last month (at a pump speed of 1.5 spm). The fluid level dropped (as expected) when the pump speed was increased to 1.9 spm and remained constant. Fluid levels dropped slightly during the early heating phase due to pump speed increases. The pump speed was increased to 3.0 spm January 20, 1989. Fluid levels over the next month were very erratic. The casing vent line was periodically freezing off.

When the vent line froze, casing pressures (Figure 5) increased and fluid levels dropped. During this period (January 24, specifically), the casing insulation failed. In general when casing pressures went up, flowline temperatures (Figure 6) went down, and vice versa. The flowline temperatures spiked when the fluid levels were high (i.e., large scale heat transfer from the casing hot spot to the fluid in the tubing can only occur when the annulus contains fluid).

The bottomhole temperature (Figure 6) was not reacting in conjunction with the flowline temperatures (further evidence of an uphole casing insulation failure). The bottomhole temperature spikes (after insulation failure) are due to wellbore flushes with hot oil. The first two major spikes (BHT) are not the result of flushing. These spikes were probably a direct result of the vent line freezing. When the casing pressure increases, the fluid level drops and a temporary no- or low-flow condition occurs across the perforations. The near wellbore heats up very quickly when the

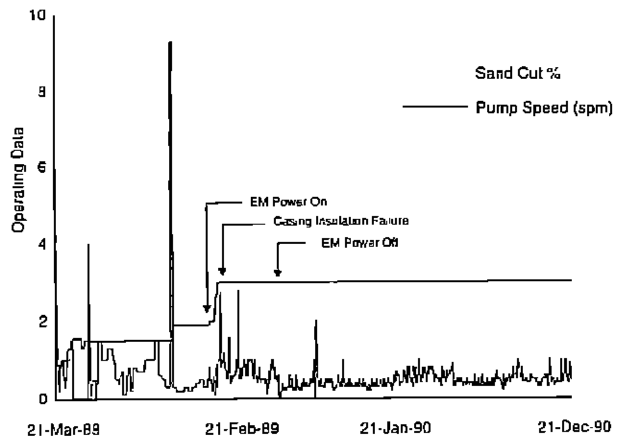


FIGURE 4: EM stimulation: Northminster A8-6 pump speed, sand cut.

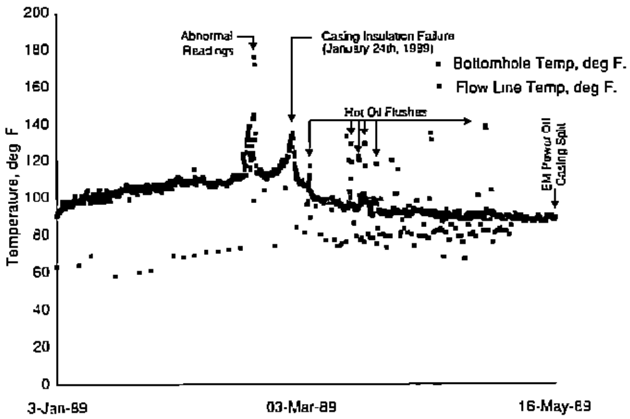


FIGURE 6: EM stimulation: Northminster A8-6 flowline and bottomhole temperatures.

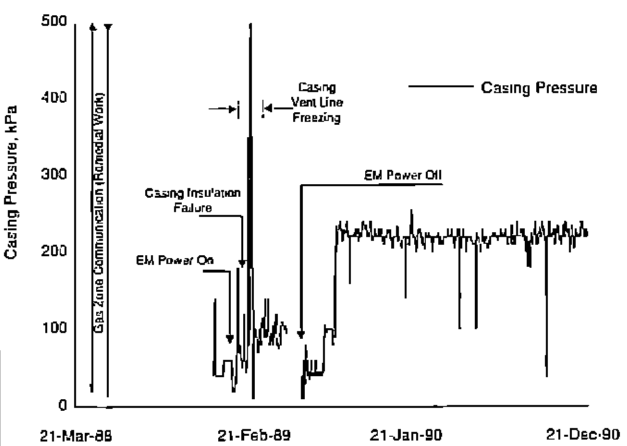


FIGURE 5: EM stimulation: Northminster A8-6 casing pressure.

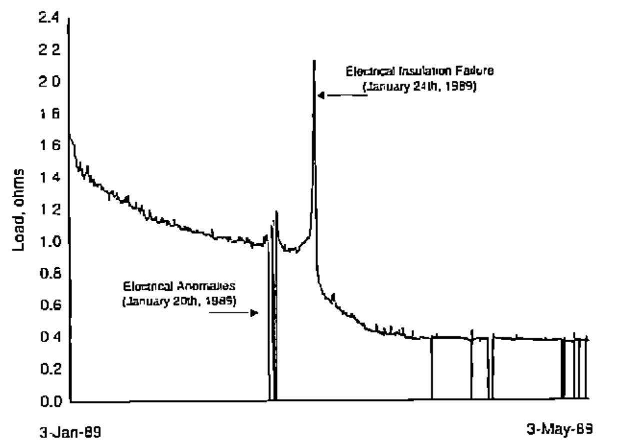


FIGURE 7: EM stimulation: Northminster A8-6 impedance/load.

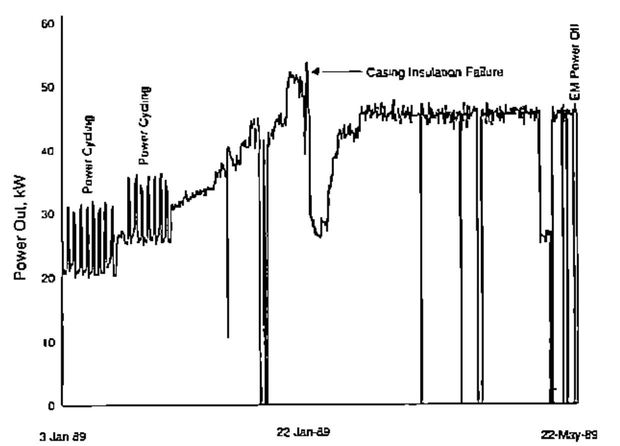


FIGURE 8: EM stimulation: Northminster A8-6 power out.

fluid flow is cut off. In general, the temperatures (both bottomhole and flowline) increased while energy was being applied to the reservoir. When the casing insulation failed, the bottomhole temperature dropped to 31°C (88°F) and not to original reservoir temperature 21°C (70°F). The average flowline temperature remained roughly constant at 26°C (80°F).

After the vent line problems were corrected, fluid levels were constant (at roughly 37 joints to the surface). Note that the fluid level during this period coincides closely to the level of the casing insulation failure.

Actual fluid levels are not considered entirely representative during this period. The sonic reflection is actually picking up the hot spot. Fluid levels were still fluctuating around the casing insulation failure as indicated by the flowline temperature spikes during the same period.

Fluid levels (after the casing split was repaired) started out at roughly 30 joints of tubing to the liquid surface. The fluid level dropped steadily (as expected with a solution gas drive reservoir) to 37 joints where it levelled off. The fluid levels after this point are actually showing the casing split, not the operating fluid level. With some procedural modifications, representative fluid levels were obtained in the fall of 1990. The current operating fluid level is around 47 joints. Sand cuts (refer back to Figure 4) at the Northminster project have remained low (less than 1.0%) and have not been a problem. As a result, the well has not required flushing with load oil on very many occasions (refer back to Figure 3).

The key electrical data is plotted in Figures 7 and 8. The impedance/load (Figure 7) started out at 1.77 ohms. The impedance began dropping towards an asymptotic limit of 0.75 to 0.8 ohms. On January 20, some anomalous points occurred but the impedance resumed its original decline. On January 22, the impedance began climbing, peaking at 2.13 ohms on January 24. The impedance then dropped sharply, levelling off towards a new asymptotic limit of 0.3 to 0.35 ohms.

The power output (Figure 8) to the well was started at a

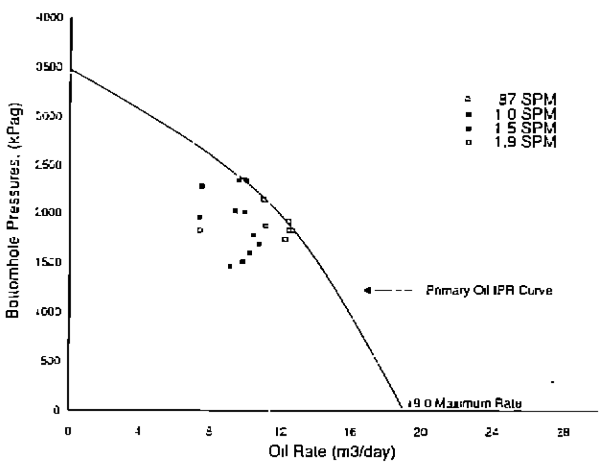


FIGURE 9: Inflow performance relationship: Northminster A8-6 (primary).

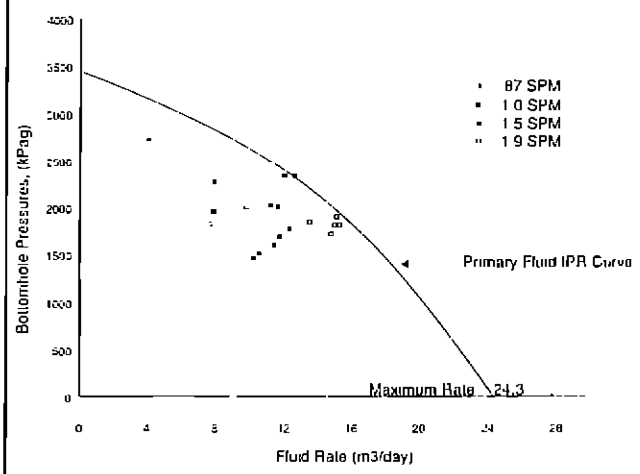


FIGURE 11: Inflow performance relationship: Northminster A8-6 (primary).

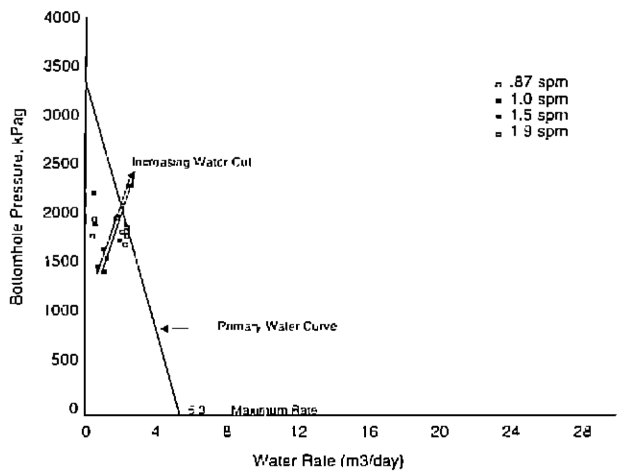


FIGURE 10: Inflow performance relationship: Northminster A8-6 (primary).

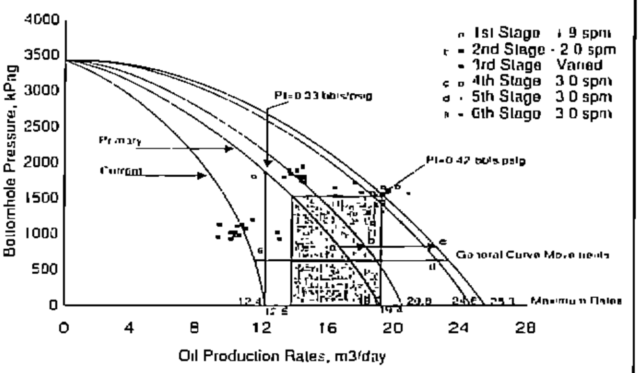


FIGURE 12: Inflow performance relationships: Northminster A8-6 oil production (enhanced).

baseline level of 20 kW with four hour spikes of 30 kW (two daily). The pulsing strategy was recommended to heat the formation quicker without adding significant risk of insulation damage. The baseline power rate was increased to 25 kW on January 8, 1989. The power pulses were increased in magnitude to 35 kW. On January 12, the baseline power rate was increased 30 kW with no pulsing. Power rates gradually increased to 50 kW. On January 24, the casing insulation failed and power rates were cut back to 28 kW. The rates were then increased to 47 kW and kept at that level until power input was terminated.

Inflow Performance Relationships – Northminster

A selection of primary Inflow Performance Relationship (IPR) curves are detailed in Figures 9, 10 and 11. The data points on the oil IPR curve (Figure 9) reflect the general production capability at each pump speed increment. Pump speeds of 1.0, 1.5 and 1.9 spm yielded average oil production rates of 7.5, 10.0 and 12.0 m^3/day respectively. The oil IPR curves fit closely with the standard Vogel equations during the latter part of the well's primary production period. This production period corresponds to pump speeds of 1.5 and 1.9 spm. The well had not produced long enough (at the other pump speeds) to reach equilibrium. Even at 1.5 spm, the well exhibited a cleanup phase. As a result, the primary oil IPR curve was maximized to ensure the results of EM heating are not overstated.

As time progresses, the oil IPR curves will shift downwards due to water cut increases (dominant in the early production phase) and depletion (more important later in the well's life). This analysis does not use adjusted IPR curves. As such, the results may be slightly pessimistic. A review of the primary water IPR curves (Figure 10) illustrates their dynamic nature. The curve shifts outward with time as illustrated by the 1.5 spm data points. The curve shifts outward because the water cut rises quickly during the early production phase of heavy oil wells. The curves will eventually begin dropping back again as depletion becomes a factor and the water cut begins levelling off.

The total fluid IPR curve (Figure 11) is just a compilation of the oil and water IPR curves. As such, the data reflects the same characteristics as the oil IPR curve.

Figures 12, 13, and 14 outline the dynamic nature of the post primary IPR data. The analysis showed that incremental oil (attributable to the EM process) is being produced. The stimulation ratio was 1.27 (i.e., the productivity index (PI) increased from 0.33 to 0.42 bbls/psig). The peak production rates occurred in the week following the January 24, 1989 failure in the power delivery systems. As mentioned earlier, the data has been manipulated to ensure that the results are not overstated. A higher stimulation ratio (1.56) was obtained during the test but it was based on only four days worth of data.

Incremental oil production due to pump speed increases alone would be represented by movement down along the original IPR curves. A portion of the improved oil rates (from 12.5 up to 19.4 m^3/day) is due to increased pump speeds. Figure 12 illustrates the incremental breakdown at peak rates (1.4 m^3/day due to pump speed increases and 5.5 m^3/d due to EM heating). The analysis yielded IPR curves which were shifted outward from the

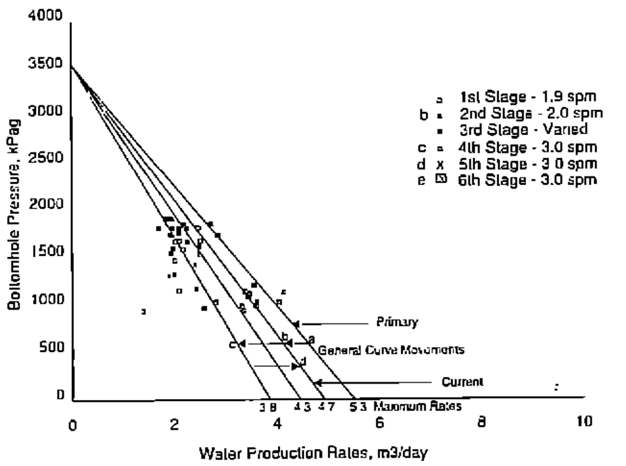


FIGURE 13: Inflow performance relationships: Northminster A8-6 water production (enhanced).

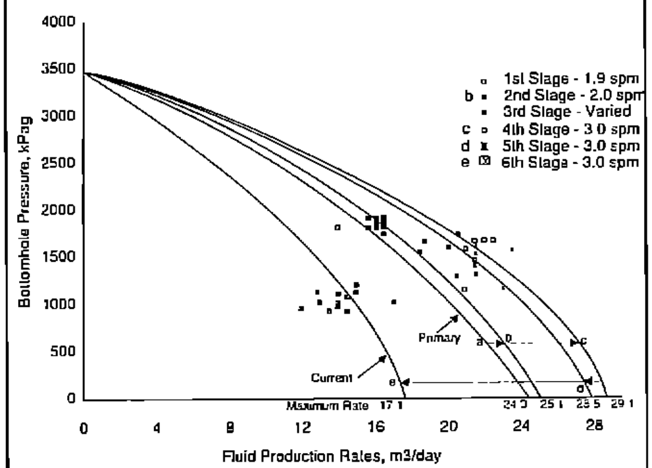


FIGURE 14: Inflow performance relationships: Northminster A8-6 fluid production (enhanced).

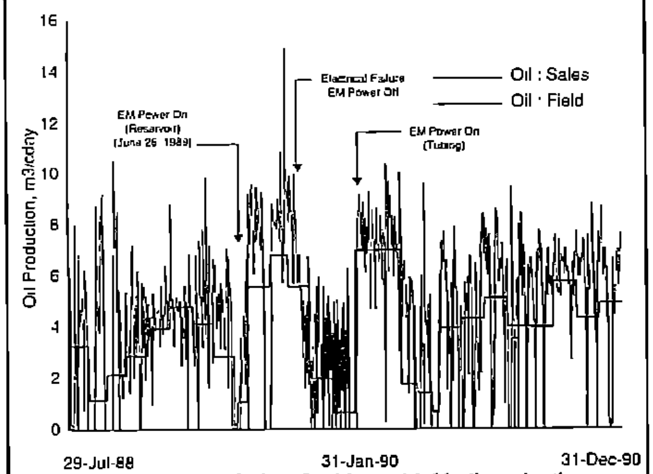


FIGURE 15: EM stimulation: Lashburn A1-11 oil production profile (cday).

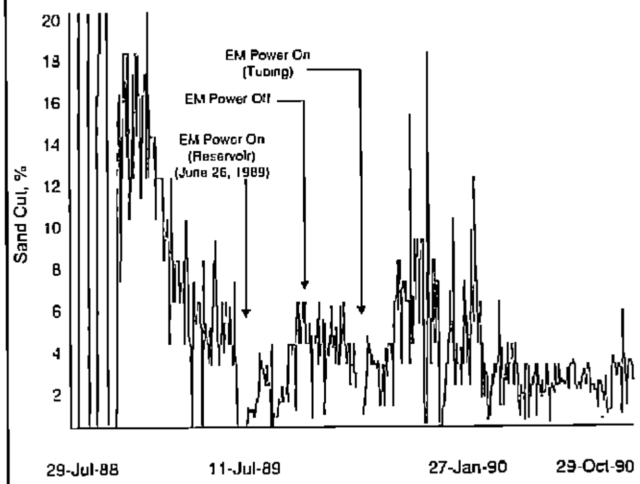


FIGURE 16: EM stimulation: Lashburn A1-11 sand cut.

unstimulated IPR curve. During the first stage of heating, the curves began shifting outward. The maximum IPR curve was reached during the fourth stage. The IPR curve then began shifting back towards the unstimulated case (as expected due to the electrical delivery failure). In general, most data points (with stimulation) indicated an oil production improvement had been achieved.

The most recent data is below the original primary IPR data curve. The Northminster location has produced a significant volume of fluid. As a result, the well has experienced some depletion and the IPR curves have shifted inward from the originally established primary IPR curve. The late time data is at a higher pump speed (3.0 spm) than the data points used to generate the primary IPR curve. The maximum pump speed under early primary production was 1.9 spm. If depletion was not a factor, the pump speed increase would have been reflected by a move down along the primary IPR curve.

Figure 13 represents the detailed results of the water IPR curve analysis. The key feature of the plot is the general position of the data points. Virtually all of the data points are to the left of the primary IPR curve. This indicates an improvement in the water production characteristics. A response of this nature is expected due to the disproportionate improvement in mobility as a result of heating oil and water. An economic benefit is obtained through the improvement in water production characteristics (i.e., lower operating costs). The late time data (post-heating) has in general moved gradually down on the plot. The water production has maintained a relatively consistent rate while operating bottomhole pressures have been dropping. The water IPR curve has followed the same general path as the oil IPR curve but not to the same magnitude. Depletion is the controlling factor. The total fluid IPR curves (Figure 14) reflect the same data as the oil IPR curves.

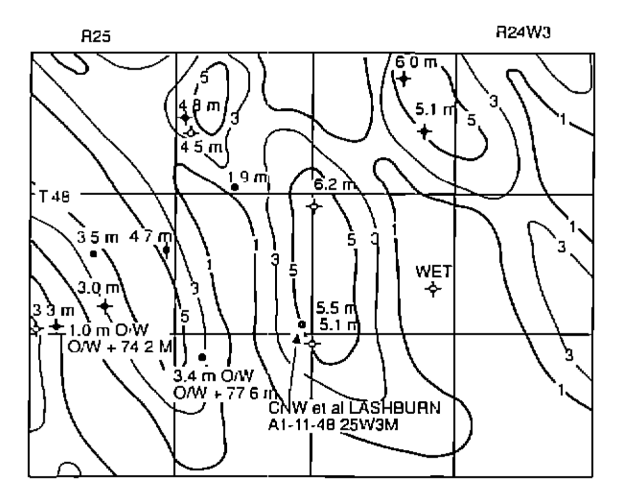
A few generalities should be kept in mind. The plots are based on field data. Actual production numbers will not be exactly the same as the reported field data. In the case of Northminster A8-6, the field and actual numbers are very close (as evidenced by Figure 1). In relative terms, the field numbers are fully acceptable for the preceding analysis. Not all data points have been included on the plots. Points were omitted where load oil had been pumped down the wellbore and where some obvious pump inefficiencies were occurring.

Lashburn, Saskatchewan, Canada
(A1-11-48-25 W3M)

This field is located 22 miles southeast of the city of Lloydminster. The well produces a very viscous 11.4° API crude oil from the Sparky formation. The geological interpretation is included as Map 2.

Main Operating Highlights:

27/07/88 = Initial primary production
26/03/89 = Sanded-in over spring breakup (last primary prod.)
26/06/89 = Reservoir heating commenced
06/09/89 = Anomaly occurred in the electrical delivery system
15/09/89 = Reservoir heating terminated
02/12/89 = Wellbore heating commenced



MAP 2: Lashburn – Sparky Sand net pay.

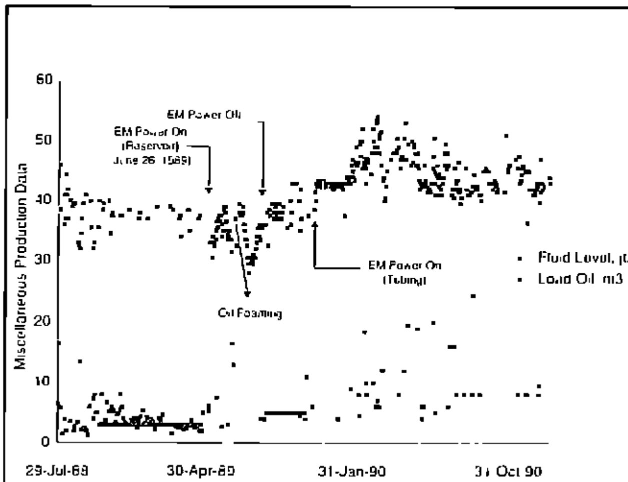


FIGURE 17: EM stimulation: Lashburn A1-11 fluid level, load oil.

The primary production at Lashburn A1-11 can best be described as erratic. Oil production (Figure 15) was erratic due to operating parameters. The well is subject to high sand cuts (Figure 16). Productivity was maintained through regular flushing of the wellbore with load oil (Figure 17). As the sand cuts dropped, the loading frequency was also reduced. Under primary conditions, the well's production peaked around 5.0 m³/day (but was already declining prior to EM heating).

The well sanded-in just prior to spring break-up in 1989. The well was placed back on production at a high water cut (Figure 18). Once EM heating was initiated, the water cut dropped rapidly. Note that not all of the water cut improvement is due to EM heating. A similar water cut response occurred later in the well's life (with no reservoir heating benefits). The well is prone to coming back on at high water cuts following a prolonged shut-in period.

Oil production was noticeably higher while the well was being heated. Oil rates quickly rose to the 8 - 9 m³/day range. The rates dropped just as quickly once the electrical power was shut off. For a period of two months (following EM heating), the well's productivity dropped into the 2 - 3 m³/day range. Once again, the well required daily flushing to maintain productivity. During this period, the well experienced rod fall problems (due to the viscous nature of the crude). To correct the rod fall problems, the electrical configuration was modified to allow wellbore heating. The result was an immediate jump in production (to the 7 m³/day range) and a reduction in load oil requirements. Production since spring breakup 1990 has averaged just under 5 m³/day (on a calendar day basis). Operating day oil production is closer to 6 m³/day. Loading is still required on a periodic basis.

Both the reservoir heating and tubing heating configurations produced similar responses on the oil production curves. An important difference becomes evident when the fluid levels (Figure 17) are reviewed. While the reservoir was being heated, fluid levels ranged between 30 and 40 joints of tubing from the surface. Without reservoir heating, fluid levels dropped into the range of 40 to 50 joints of tubing from surface. The benefits of reservoir heating are apparent and will be quantified when the inflow characteristics are discussed. The fluid level characteristics during August 1989 are important to note. The sharp rise in fluid levels (indicated on Figure 17) is the result of oil foaming and not an indication of improved inflow. The fluid level numbers have to be neglected through this type of period. The foaming problem disappeared when the pump speed was increased to 2.0 spm.

The pump speed (Figure 19) was around 1.2 spm throughout most of the well's history. A review of the fluid rate curves (Figure 20) indicates improved fluid production after spring break-up (1989) despite a consistent pump speed. The data suggests that the inflow characteristics need to be studied in detail to quantify the relative effects of the pump change and the various stages of heating.

An additional benefit to heating was obtained as shown on the tubing pressure plot (Figure 21). Under primary conditions, the tubing pressure was significant (especially during the winter months). While being heated the tubing pressure was not a factor. With reduced operating pressures and higher temperatures, there is reduced equipment wear and failure and fewer cold weather related problems. The improved operating conditions can recover

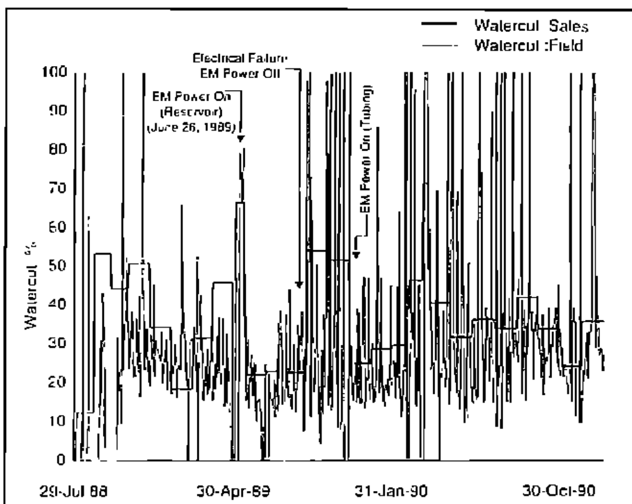


FIGURE 18: EM stimulation: Lashburn A1-11 watercut.

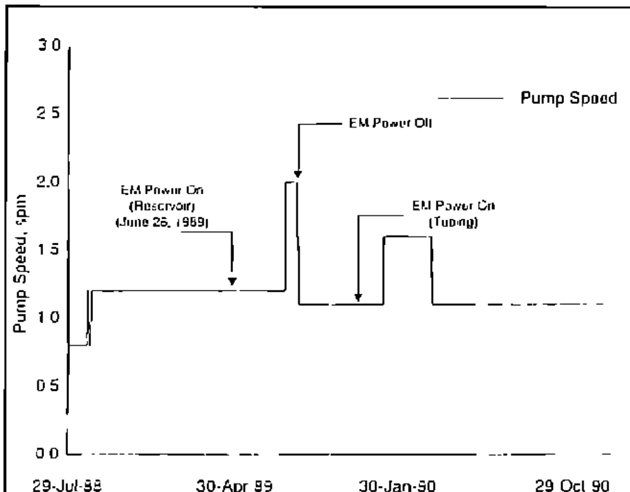


FIGURE 19: EM stimulation: Lashburn A1-11 pump speed.

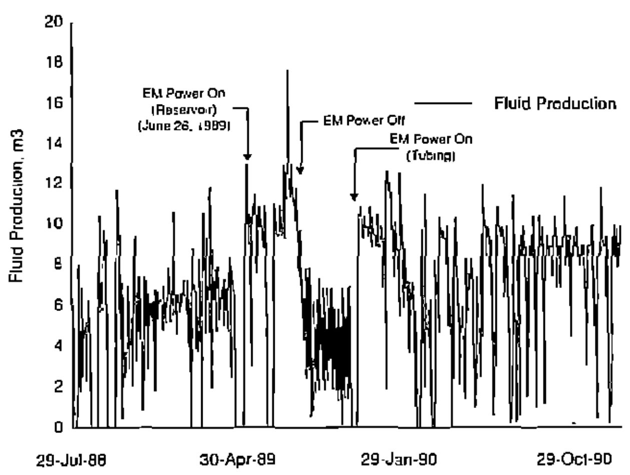


FIGURE 20: EM stimulation: Lashburn A1-11 fluid production.

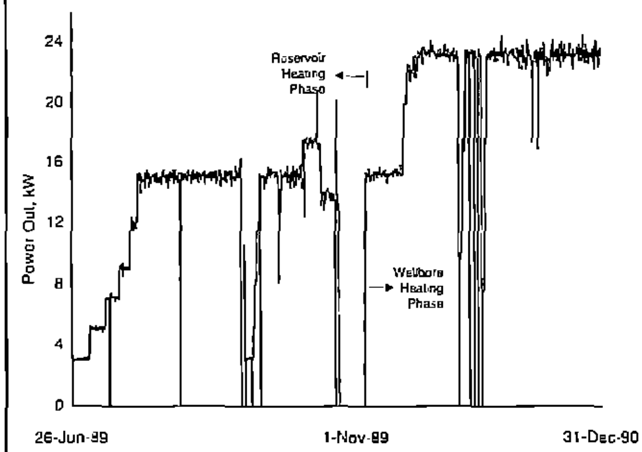


FIGURE 23: EM stimulation: Lashburn A1-11 power out.

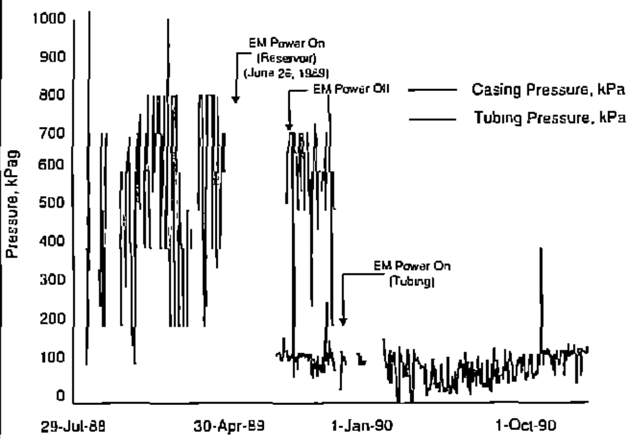


FIGURE 21: EM stimulation: Lashburn A1-11 operating pressures.

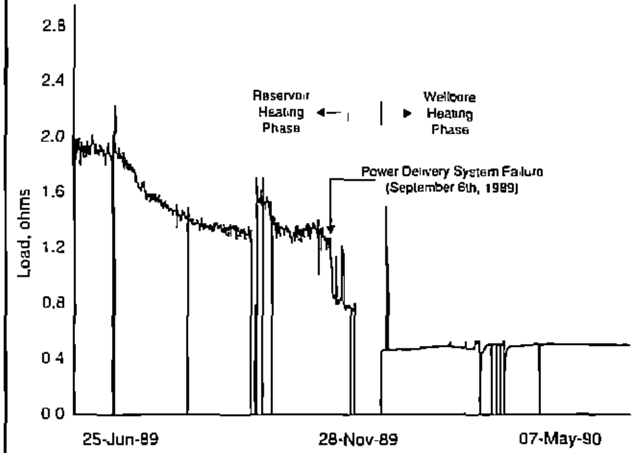


FIGURE 24: EM stimulation: Lashburn A1-11 impedance/load.

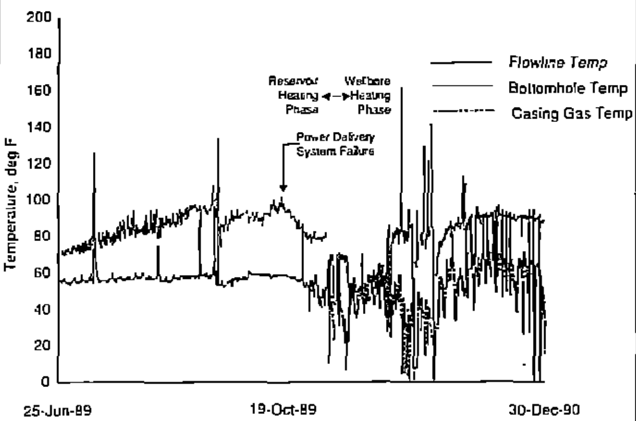


FIGURE 22: EM stimulation: Lashburn A1-11 flowing and bottomhole temperatures.

a portion of the invested costs.

A number of temperature and electrical readings (Figures 22, 23 and 24) were monitored. During the reservoir heating phase, two thermocouples were positioned to monitor bottomhole temperatures. The downhole configuration is shown on Figure 25. As shown, the bottom sensor sat below the perforations (at or near the pump intake). The upper sensor was positioned across from and near the top of the perforations. Only the upper BHT has been plotted. The lower thermocouple failed early in the project.

The temperature profile (Figure 22) can be discussed in general terms. During the initial heating phase, the BHT increased steadily to 36°C (97°F) (an increase of roughly 25°). The flowline temperature (FLT) increased roughly 5° over the same time period. The well developed sand problems and was shut-in for a few weeks. Temperatures dropped during shut-in. Once heating was resumed, the temperature climbed back into the same range observed earlier. Bottomhole temperatures began dropping immediately after the power delivery system failed, levelling off towards the original reservoir temperature. Flowline temperatures declined continuously as a result of declining ambient temperatures.

With the implementation of wellbore heating, the bottomhole thermocouples were pulled and replaced by an uphole thermocouple to measure casing gas temperatures. The casing gas data is influenced strongly by the atmospheric temperatures and can only be used as a general indication of downhole heating. The flowline temperatures responded much stronger and quicker under the wellbore heating scenario.

The electrical power (Figure 23) was energized at 10:40 a.m. June 27, 1989. The power output to the well was started at a baseline level of 3 kW. The power level was increased in small incremental steps to 15 kW. During the reservoir heating phase, power output was generally in the 13 to 18 kW range. The power levels were kept low, to minimize the risk of casing insulation failure.

The impedance/load (Figure 24) reacted in much the same

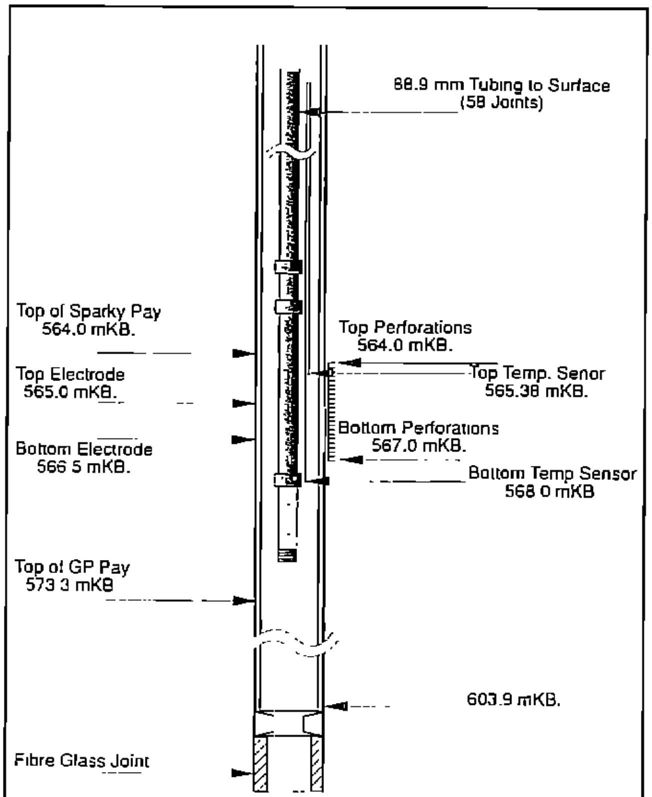


FIGURE 25: CNW Lashburn A1 - 11 - 48 - 25 - W3M completion schematic.

fashion as the Northminster well. Initial impedances started around 2 ohms, declining towards an asymptotic limit of roughly 1.2 ohms. When the power delivery system failed, the impedance took a sharp step drop and began declining towards a new asymptotic limit.

Under the wellbore heating scenario, the electrical properties have been virtually constant. Power input levels have remained around 23 kW, the impedance remained constant at 0.5 ohms and flowline temperatures remained in the 29 to 32°C (85 to 90°F) range. The consistency is of special importance. Power delivery on a consistent basis is important in any economic consideration.

Inflow Performance Relationships – Lashburn

The general quality of the data is not as refined as Northminster A8-6. The data is fairly scattered and the number of points which were usable were limited because of well loading, workovers, etc. The primary oil IPR (Figure 26) is based on a statistical average of all the data points. The curves were chosen based on a comparison of the well's production history and the average production from the IPR data (5.2 m³/day at a bottomhole operating pressure of 1,802 kPa). The oil production data (based on field numbers) tends to be high because actual water cuts are generally higher than those reported in the field. The high viscosity crude forms an emulsion that does not easily separate out. The well's primary production peaked at 4.8 m³ per operating day and had since declined to around 4.0 m³ per operating day. With all things considered, justifying an oil production rate higher than 5.2 m³/day is difficult.

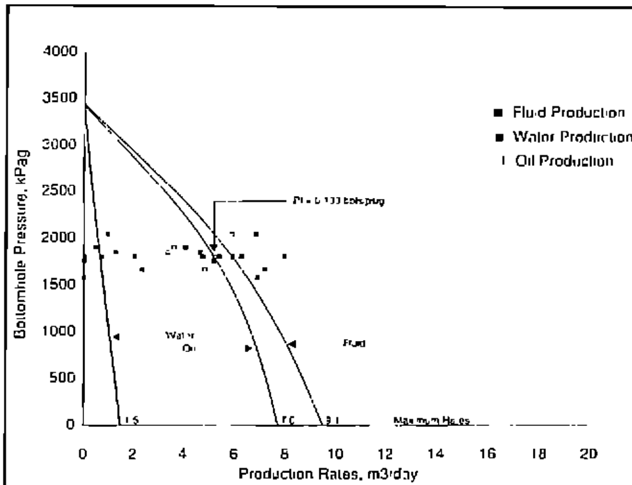


FIGURE 26: Inflow performance relationships: Lashburn A1-11 primary production.

The primary water IPR curves (Figure 26) do not have any unusual characteristics. Early curves were along the vertical axis (i.e., the well was producing clean oil). As water cuts rose the curves moved outward. The water cuts through the primary stages were somewhat erratic as indicated by the scatter on Figure 26. The total primary fluid IPR curves are also shown in Figure 26.

The stimulated oil IPR curve (Figure 27) showed that incremental oil (attributable to the EM process) is being produced. The data sets shown were chosen to highlight the movement of the curves (with time) and to quantify the different operating stages of the well's post primary production period. Operating parameters [pump speed and efficiency and heating (reservoir vs. tubing)] are consistent within each stage. The IPR curves began shifting out as soon as EM heating commenced. The productivity index (PI) increased from 0.133 to 0.267 bbls/psig (a stimulation ratio of 2.01) during the second stage. The well developed some

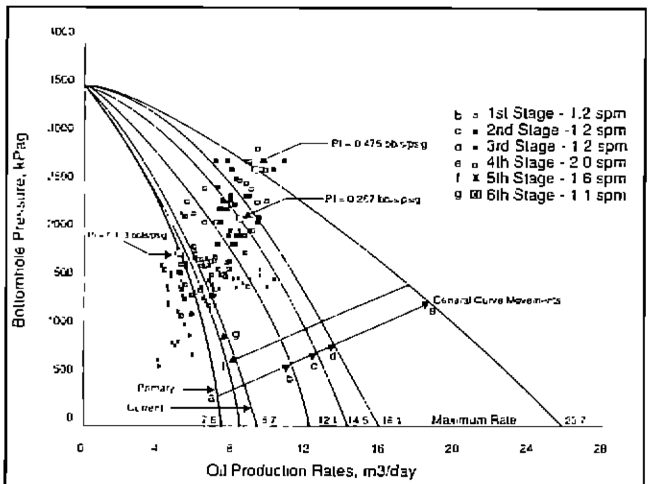


FIGURE 27: Inflow performance relationships: Lashburn A1-11 oil production (enhanced).

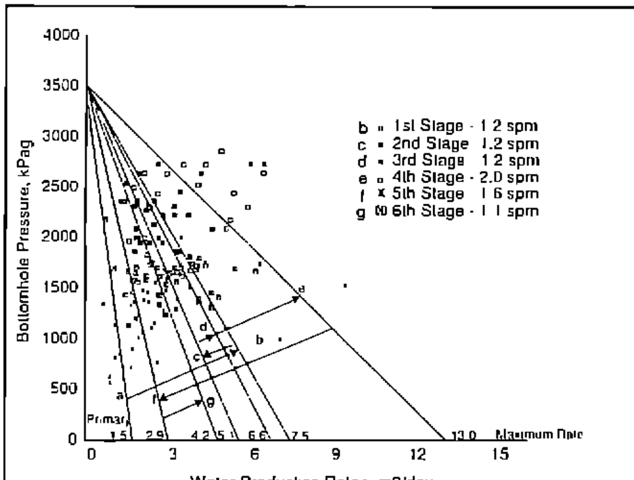


FIGURE 28: Inflow performance relationships: Lashburn A1-11 water production (enhanced).

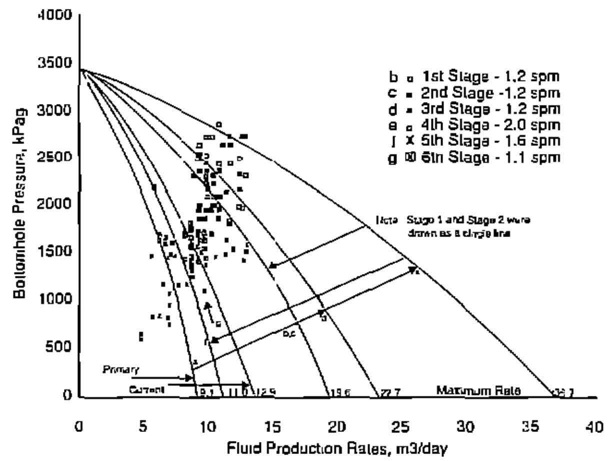


FIGURE 29: Inflow performance relationships: Lashburn A1-11 fluid production (enhanced).

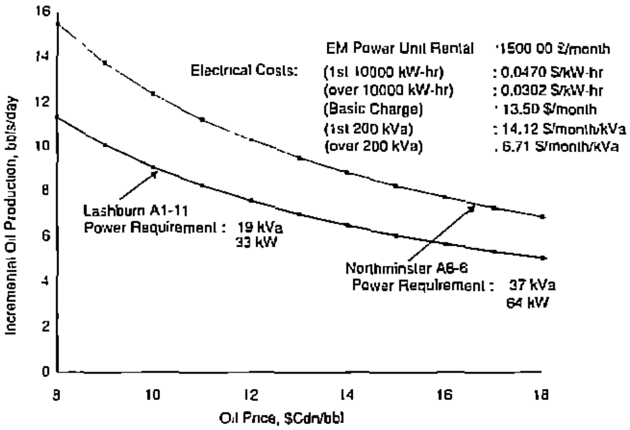


FIGURE 30: EM stimulation: A1-11 Lashburn/Northminster A8-6 economic incremental oil vs. oil price.

sanding problems and was shut-in for a period of time. EM heating during the third stage continued to inflate the IPR curves. However, data was strongly influenced by oil foaming and should be neglected for the most part (i.e., the bottomhole pressure values are suspect).

The improved inflow experienced during the third stage, prompted a decision to increase the pump speed to 2.0 spm for the fourth stage. During this stage, the IPR curves continued to advance outward. The PI peaked at 0.475 bbls/psig during this stage. Based on a primary PI of 0.133 bbls/psig, the stimulation ratio would be 3.57. These numbers need confirmation with new tests (i.e., the data is close to the foaming problem and may have been affected). It was during the fourth stage, that the electrical delivery system failed. Without the heat to sustain production rates, the well's productivity quickly dropped (as discussed before). The data in the two months following reservoir heating was not evaluated on an IPR basis because operating practices were constantly influencing production performance.

Two production periods were evaluated during the tubing heating phase. One important feature of these data points is their proximity to the primary IPR curve. With the tubing heating configuration, this result is expected. Under this scenario reservoir inflow is not being affected and as a result the data points should follow the primary IPR curve. They also react as expected to pump speed changes. When going from a pump speed of 1.6 spm down to 1.1 spm, the data points should (and do) move up along the IPR curve. The other important feature is evident when the reservoir and tubing heating data points are compared on a group basis. The contrast between the two is strong evidence that the EM heating (reservoir) is providing a very beneficial effect. The Lashburn well would not be capable of economic oil production without the tubing heating system in place. However, given the choice, reservoir heating is the logical alternative. It should be mentioned that tubing and reservoir heating can occur simultaneously which is advantageous under some scenarios.

The water IPR curves (Figure 28) over the same corresponding stages stay within a reasonably well defined range. In general, they move out during the reservoir heating phase (because fluid production rates were increasing faster than water cuts were decreasing giving a net effect of increased water production).

Once reservoir heating was terminated, the water IPR curves moved back into the range of the primary water IPR curve. The water data points responded to changes in pump speed in much the same fashion as the oil data points. The fluid IPR curves (Figure 29) confirm the general production trends discussed under the oil and water IPR sections. The fluid IPR curves (corresponding to similar pump speeds) follow each other closely where pump efficiencies are also consistent.

Incremental Economics

A secondary analysis was conducted to quantify the incremental oil rates required to justify the incremental electrical cost (Figure 30). Note that the analysis does not look at the overall economics of the process. A full range of oil prices were considered. Both wells, (while being heated), were producing sufficient incremental oil even at low oil prices. At low prices other factors result in uneconomic production at the Lashburn well. It is important to note that the Lashburn well would not be capable of economic production, if the well was not being heated.

Conclusions

A number of key points came out of the preceding analysis. First and foremost, there was a positive production response obtained through the application of electromagnetic (EM) heating. The pilot projects (Northminster and Lashburn) had peak stimulation ratios of 1.27 and 3.75, respectively (a minimum of 2.01 at Lashburn). In both cases the electrical delivery system failed and production (productivity indexes specifically) quickly dropped back toward primary levels. Both projects indicated a quick response to heating even at low power input levels. At the time of the failure, the inflow characteristics were still improving. Neither project had been heated for a substantial period of time (Northminster – three weeks, Lashburn – two months). With longer-term heating, the stimulation ratio could be improved. As a note, the effects of long-term EM heating (incremental production and reserves) have already been addressed[1]. Their evaluation (based on reservoir simulation) suggests both incremental production and reserves.

The economic potential of the process cannot be realized without long-term heating. The pilot projects conducted on CNW properties have been casing delivery configurations. The mechanical problems (casing insulation failure) of this particular configuration make long-term heating doubtful. The cable delivery system being evaluated by EOR International and other companies is more suited for long-term heating. The benefits include serviceability and a reduced capital exposure on downhole, non-retrieveable equipment (i.e., insulated casing). The economics of proven long-term EM heating are obvious. For a capital investment of 25 - 30% over normal well costs, the production can be improved by a minimum factor of 2 for a typical heavy oil well.

The tubing heating configuration has some possible applications in areas where rod fall problems are prevalent. The process can be adapted to existing well installations. The economics would be largely dependent on the availability (and cost) of power in the area.

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