5 CASE HISTORIES: LUSELAND FIELD & HORIZONTAL WELLS

5.1 Luseland Field History and Reservoir Parameters

The Luseland Field in Saskatchewan is a particularly important case history for a number of reasons:

- It has been on production continuously since 1982.
- Since 1984, there have always been approximately 30 vertical wells on production, allowing direct gross average field production comparisons over time.
- Wells were drilled on 40-acre spacing, and there has been no infill drilling in this field during the study period.
- The company that operated the field (Wascana Energy, previously Saskatchewan Energy, and now a subsidiary of Nexen Inc.) installed and tested a group of six horizontal wells in the same field during the period 1992-1994.
- Old vertical wells were converted to CHOPS production in during the years from 1994 to 1996.
- Recompletions with larger-diameter perforations and conversions to higher capacity PC pumps were undertaken on selected wells during 1994 to 1997.

Thus, the Luseland Field allows a direct and unbiased comparison of field performance under three different conditions: horizontal wells in three different areas of the field, vertical wells with minimal sand production, and production from the identical vertical wells, but with deliberate encouragement of sand influx (CHOPS). The basic properties and parameters of the Luseland Field are presented in Table 5.1 along with a comparison to a west-central portion of the heavy oil belt (Faja del Orinoco) in Venezuela.

Table 5.1: Luseland and Faja del Orinoco Properties

Parameter	Luseland	Faja del Orinoco
Depth – z	730 m	400-800 m
BHSP - p_o	6.3 MPa	3.8-8.0 MPa
As % of $\gamma_w \cdot z$ (hydr)	86%	>90-95%

Bubble point (%p_o)	95% of p_o (?)	>90% of p_o
BHST – T	30ºC	44-60ºC
Porosity - ϕ	~30%	29-31% *in situ*
Permeability - k	2 – 4 D	1 – 15 D
S_w, S_g	0.28, 0.0	~0.15, 0.0
Zonal thickness - h	5-15 m	6-40 m
Viscosity *in situ* - μ	1400 cP	500-6000 cP
Dead oil viscosity	12,000-30,000 cP	??
API gravity (º)	11-13.4ºAPI	8-11ºAPI
Solution gas type	>90% CH_4	>90% CH_4
Gas solution const.	0.20 bar^{-1} ~50 scf/B - 500m	~0.20 bar^{-1} ~50 scf/B - 500m
k·h/μ (in Darcy-metre/centipoise)	5-50 m·D/cP	12-400 m·D/cP
Lithology	Uncemented quartz-rich sands	Uncemented quartz-rich sands

For the Venezuelan case, parameter values have been given as a range for the shallower reservoirs in the southern part of Zuata Province. The Luseland parameters are quite "typical" of heavy oil in Canada except for one item: S_w is more typically in the range 0.12-0.16, rather than the 0.28 value presented.

5.2 Production History for Luseland Field

Figure 5.1 is a plot of the monthly oil and water rates in m^3/month produced from the Luseland Field from its inception to Dec 1998.[36] Four distinct phases are defined.

Phase I is the ~10 year initial period. The wells were completed with conventional widely spaced, small-diameter perforation openings (probably all 13 shots/metre with 10-12 mm openings). Reciprocating pumps were used to achieve production rates of ~20-30 b/d of oil, although a few wells had PC pumps installed in the late 1980s; apparently the wells were not reperforated at this time and the PC pumps were not highly successful. During this phase, small amounts of sand entered the well, probably ~0.25% to 2% by volume of produced liquids in each well. Thus, CHOPS processes were occurring, but limited by the rate at which the well could be produced and by the size of the perforation ports. Careful examination of the data shows that the wells were slowly becoming more productive with time. This can be partly ascribed to the increase in rate that develops as a more permeable zone grows around each CHOPS well.

Phase II involved drilling and producing a set of six horizontal wells with slotted liners or open-hole completions. These six 500 m long wells were drilled in three different geographical regions in the same area, but one of them was placed centrally in the best area of the field near where the ~30 original vertical wells were producing. Table II contains the production history for 5 of the 6 horizontal wells (the sixth never produced oil).

Table 5.2: Luseland Field Horizontal Well History

Well No	Total Oil m^3	Total H_2O m^3	Well life (mo)	Ave. oil prod. (m^3/mo)	Ave. H_2O prod. (m^3/mo)
91^15/12	40	1820	8	5	225
91^2/13	705	1515	6	118	252
91^10/9	4870	1615	59	82	27
91^9/9	6850	1245	30	228	41
91^7/9	10940	6015	48	227	125

Clearly, the Phase II horizontal wells were failures. Figure 5.2 shows the production history of the most productive one, Well 91^7/9, that produced just over 68,000 bbl.

Phase III is the CHOPS phase for the Luseland Field. Starting in late 1993, a change in philosophy took place, and over a number of years, the original ~30 vertical wells were gradually recompleted to aggressively produce sand. This involved reperforating the interval using large diameter entry ports (20-22 mm) and more closely spaced charges (26/m) so that larger volumes of sand and oil could enter the wellbore unimpeded by perforation restrictions. Reciprocating

[36] Care must be exercised in field data analysis and comparisons; price collapses in 1990 and 1997 caused many heavy oil operators to alter their production rates and to focus on good wells, shutting in poorer wells. Thus, a production history for a well or a field may reflect market forces as well as production practices.

pumps were replaced by PC pumps, with the base of the pumps seated about 1 m below the lowermost perforation port.

Operation of the PC pumps was gradually optimized over a period of many months to several years for each well. PC pump efficiency in CHOPS wells is generally optimal when the fluid level in the annulus is maintained low, yet not so low as to allow gas to enter the pump. This applies the maximum drawdown to the formation without risk of burning the pump, which can happen rapidly if the well is operated without fluid. Over time, individual well production was adjusted so that fewer that 10 joints of fluid (<100 m) were maintained in the annulus. Larger capacity PC pumps were installed in several of the best CHOPS wells in the period 1996-1997, and this further boosted oil production rates in the field. In five wells in 1997, tubing size was increased to 4.5″ (112 mm diameter) so that a higher torque could be used in the wells without backing off the tubing or impairing it through excessive torque.

By 1997-1998, well conversions and optimization had resulted in an increase in the overall oil production rate by a factor of about four to five, compared to the period 1982-1992. On an individual well basis, pre-1993 production was ~4.5 m^3/well; after 1997, it was 21.6 m^3/d. A series of typical well histories is presented in Figures 5.3, 5.4 and 5.5.

Phase IV started recently, in the middle 1990's. This phase has involved drilling additional (step-out) wells off the center of the structure, and this drilling program has had mixed results. Some of the wells are good CHOPS producers, but some of the wells have rapidly become poor oil producers and good water producers. It is believed that the new flank wells are producing large amounts of water early in their life because of proximity to the laterally offset zones of mobile bottom water below the regional oil-water contact that are closer to the thinner flanks.

The improvements in production have continued to the year 2001, although not at the rate of improvement in the 1994-1998 period. At the present time, the field is producing over 20,000 m^3/month of oil, and this production level is being sustained. Targeted recovery factor is now >20% of OOIP for the best central part of the reservoir, based on continued good CHOPS well performance.

5.3 Individual Well Behavior

Figures 5.2-5.5 are "typical wells" from the Luseland Field; more individual well plots can be found elsewhere.[xxvii] Some comments are warranted for each well to explain the data.

Well 91^7/9 is the best of the six horizontal wells drilled in the early 1990's. Within a year after production started, a strong trend in increasing water cut was accompanied by a drop in oil rate to below economic levels. Workovers and other attempts to establish good oil rates did not succeed, and the well was finally abandoned in 1998. Based on a well cost approximately four times that of a vertical well (CAN$1,000,000 vs. CAN$250,000 in 1992), on the average price of oil, and on typical operating expenses, even the most productive horizontal well was not an economic success. Unfortunately, this is not unusual in heavy oil.

Well 5/4 (Figure 5.3) is a vertical well that always had relatively high water cut from the first day of production. It was converted to CHOPS, and therefore subjected to more aggressive drawdown. Generally, this would be expected to immediately accelerate the rate of water cut increase, but the opposite happened. For the first decade of the well life, the average water cut was approximately 50%, but in the period 1994-1998, the water cut dropped to about 30-35% (one part in three). At the same time, the oil production rate changed from 22 b/d to over 100 b/d.

Well 14/7 (Figure 5.4) produced for the first 12 years of its life on a reciprocating pump. It actually showed a declining water cut, going from a WOR of >1.0 in the first two years to a value of ~0.25 in the period 1991-1993. At about 1994 it was converted to CHOPS, and oil production rates began to rise substantially, initially without the water cut increasing. However, sudden water breakthrough occurred within about a year, at the end of 1994, and attempts to restore oil production have not succeeded. This well produced just less than 100,000 bbl of oil. It is widely accepted that, for a cheap vertical well in these heavy oil fields, payback and operating expenses are met if about 30,000 – 60,000 bbl are produced (depending on price and workover requirements). Therefore, this well was likely a marginal moneymaker for the company, providing that it did not require a large number of workovers.

Well 18/16 (Figure 5.5) produced on a reciprocating pump for a number of years at modest rates that increased to ~40 b/d before water breakthrough took place, resulting in the well being shut down for three years. In late 1993, the well was converted to CHOPS, and the oil rates climbed to over 100-200 b/d and stayed there for over three years before oil production once again began to drop off. However, during the oil rate drop-off in 1997-1998, the WOR did not rise. This indicates that oil rate loss was linked to depletion of the reservoir energy in the well vicinity. GOR values were stable for the period marked on the plot, but the GOR values began to rise in 1997 at the same time that the oil rates began to drop; by the end of oil production in 1998, GOR was 5-6 times higher than in 1996. It appears that a continuous gas phase developed at about this time, and this caused depletion of the foamy oil drive mechanism in the well vicinity. This well produced about 250,000 bbl over its life, about 80% of this in the second phase of the well's life, after it was placed on CHOPS production. Thus, the CHOPS phase was highly profitable for the company in this well.

5.4 Field Behavior

The total historical liquid production volumes for all the vertical wells in Luseland are plotted in Figure 5.6; clearly, the examples shown in the previous figures are not the "best" in the field, by any means. Figure 5.6 includes not only the 30 original wells that were converted to CHOPS, but also the higher-risk wells drilled in the 1990's on the flanks of the structure; generally, the high-risk wells and the new wells plot to the left hand side of the diagram, and careful examination shows that most had very high water cuts, which suggests why they were generally shut down after a short production period.

This figure shows that the overall average cumulative oil production in these wells is about three times the water production. If the high-risk wells and all wells drilled since 1990 are removed, the average oil produced is on the order of 230,000 b/well to 1998 (over 300,000 to 2001, based on verbal statements from the operator). For those wells with production in excess of 400,000 bbl, the recovery ratio for their individual drainage areas is approaching 20%; for the overall field, it was approaching 11% in 1998

Figure 5.7 is a plot of the average monthly water rate versus the average monthly oil rate, without correcting for the total oil rate. There is no obvious correlation between the two rates. However, if the water-oil ratio (WOR) is plotted against the oil production rate, as shown in Figure 5.8, a definite hyperbolic relationship exists. This latter plot shows that the better oil wells are generally the wells that produce the lowest amount of water. This makes sense, and yet there are exceptions; the three wells circled have shown a reasonable oil rate despite a high WOR. In fact, there are now attempts under way in Alberta and Saskatchewan to produce heavy oil in CHOPS fields using waterflooding. These efforts have achieved additional oil production, albeit in modest amounts.

Note that conventional predictions using textbook equations would never justify waterflooding in such fields, but the reality in heavy oil is often different than the theory. This is also the case with CHOPS processes: using conventional oil production prediction methods would lead to no vertical wells ever being drilled in these reservoirs!

CHOPS waterflooding projects have proven economical in that operating costs are more than met by the additional value of the incremental oil produced, but the amount of incremental oil production is not large, seldom more than one or two additional percent of OOIP. In the fall of 1999, waterflooding in a 10,800 cP heavy oil deposit north of Lloydminster was attempted using a pressure pulsing[xxviii] approach to moderate viscous fingering instability. The pressure-pulsed waterflood slowed down the sharp production decline in the CHOPS field, and this prolonged the life of the field. At the same time, water production increased, and individual CHOPS well behavior in the offset producing wells changed, with larger sand cuts observed. For the six-month period during which pressure pulsing was used to inject water, the netback to the company was about CAN$58,000/month, after all additional costs were paid.

5.5 Horizontal Versus Vertical Wells?

This is not a trivial question, and the answer is not obvious. On the basis of production data in heavy oil wells, it might seem obvious that horizontal wells should be economical, even lucrative. The logic goes something like this (using Luseland as an example):

- Verticals penetrate 10-15 m of ϕ = 30% sand, $S_o \sim 0.85$.
- As in Luseland, without deliberate CHOPS, these wells can produce 15-50 b/d, using reciprocating pumps.
- In a conventional oil reservoir, a 1000 m horizontal well might produce 5-8 times this amount (100-300 b/d).
- Thus, a $1,000,000 horizontal well will produce at least 40,000 b/yr, and with three years production, be economical.
- At least some wells producing over 100,000 b/yr can be expected, giving excellent profits.

What is the flaw in this logic? It is that the production mechanism in the second step is assumed incorrectly to be the same production mechanism as for conventional oil: Darcy-dominated flow without any ancillary positive influences from sand influx. This then leads inexorably to the remaining points of logic, so that a mistaken final conclusion is reached.

In the Alberta and Saskatchewan portions of the HOB, as demonstrated in the Luseland Field case, it is possible to find many reservoirs that have been producing 15-50 b/d per well for many years using reciprocating pumps. However, more careful examination of production practices will show that all these wells have small amounts of sand that enter the wellbore continuously with the oil. If this sand is stopped (with a screen, slotted liner or gravel pack), the oil rate will drop to only a few barrels a day. It is this latter figure (2-10 b/d, sand-free rate) that must be used in the logic sequence stated above. This leads to predicted horizontal well rates closer to 50-100 b/d, although some fields do actually produce much higher rates than this from horizontal wells. It is usually found that these successful cases are in the lower viscosity range of Alberta heavy oils (<1500 cP)

Horizontal wells are almost invariably completed using slotted liners with slot width of 40-100 μm; these serve the role of excluding formation sand. Thus, in horizontal wells in heavy oil, sand is largely prevented from entering and the production enhancement aspects of CHOPS never develop. If the correct production value is used in comparisons (sand-free oil production rate from a vertical well), it will lead to the conclusion that seldom can sand-free horizontal wells be better producers than vertical CHOPS wells in heavy oil deposits. In fields such as Pelican Lake and Amber Lake in Alberta that have been exploited with horizontal wells, the operators report that there is a small amount of continued fine-grained sand ingress. This is probably the reason that these fields were successful, providing rates that approached 300-500 b/d initially, although declining at a rate of 25-40% per year.

Is there additional proof of the comparative behavior of horizontal wells versus vertical CHOPS wells beyond the Luseland case? Fortunately, even though it was expensive for them, a number of operators have tried horizontal wells in precisely (or omit both words) the same areas where verticals were drilled and CHOPS was implemented; several of these additional case histories will be briefly presented.

The reservoir parameters for these cases are roughly similar (porosity of ~30%, temperatures in the 20-30°C range, oil viscosities in the 1000 – 10,000 μm range, absolute permeability in the 1-4 Darcy range…), although there are invariably minor differences in oil saturation, thickness, depth, initial pore pressure, bubble point, and so on. These differences among reservoirs and producing fields will not be discussed in detail because the comparisons to follow are based on wells in a small geographical area, no more than a section (2.5 km^2) in each case. This means that, the geological parameters and reservoir parameters were virtually identical for the horizontal and the CHOPS wells.

5.5.1 Lindbergh Field Horizontal/CHOPS Comparison

The Lindbergh area in Alberta, north of Township 53, has hundreds of wells producing from several formations. The specific data shown here are from wells producing from the Rex Formation. Figures 5.9 and 5.10 are the examples chosen to allow a direct comparison of wells in the same 2.5 km^2, listed in Table 5.3.

Table 5.3: Section 25 Lindbergh Vertical and Horizontal Wells

Well Location	Well Type	Total Oil – bbl (To Jan 1999)
8-25-55-06W4	Vertical	209,865 bbl oil
9-25-55-06W4	Vertical	119,030 bbl oil
11-25-55-06W4	Vertical	165,680 bbl oil
16-25-55-06W4	Vertical	290,205 bbl oil
11-H25-55-06W4	Horizontal	87,975 bbl oil
12-H25-55-06W4	Horizontal	45,455 bbl oil
13-H25-55-06W4	Horizontal	70,355 bbl oil

The Rex Formation (Grand Rapids Formation equivalent if the Cold Lake area terminology is used)) is a Cretaceous fine-grained arkosic blanket sands containing oil of viscosity ~10,800 cP under reservoir conditions with oil saturation values of 0.85-0.88.. The thickness of the producing zone is from 4 to 9 m generally, and there is no free gas or mobile water detectable in the reservoir from geophysical logs. The Rex Formation is in the “middle” of the Cretaceous Mannville group of unconsolidated heavy oil producing sands.

Figure 5.9 shows a below average to average vertical CHOPS well that produced 119,000 bbl over a life of 11 years. Generally, in this area, it is reasonable to expect more than 150,000 bbl from a single CHOPS well. The well was shut-in (production suspended) because of high water cuts in the last two months, but it was an economical well overall. Figure 5.10 shows the best of the horizontal wells from this same local area of the Lindbergh Field. Note that the oil rate dropped almost continuously from the date production started. This horizontal well stopped oil production almost entirely after only 4 years of production and less than 100,000 bbl of oil production, an unprofitable outcome. Remember that the cost of the vertical well was about $250,000, less than a quarter of the cost of the horizontal well.

Figure 5.11 shows water and oil production for the seven wells listed in Table 3. The comparison is based simply on total production to the date at which data were collected. However, the life span of the horizontal wells is relatively brief, 3-5 years generally. Also, comparisons based on a simple set of data can be misleading. For example, there is no information given on types and numbers of workovers carried out to maintain production from these wells. Nevertheless, given the high cost of the horizontal wells and the high cost of any interventions in such wells, it is reasonable to assume that the conclusion that vertical CHOPS wells are far more productive and profitable than horizontal wells is valid.

An important data point collected from these wells is that in the vertical wells, the GOR was moderate and remained constant, whereas in the horizontal wells, a much higher GOR (×5) was observed, and this tended to increase during the well life. Even without the beneficial effects of CHOPS processes, one may ascribe the sharp drop of production in the horizontal wells to rapid drainage of reservoir solution gas energy and to reduced relative permeability in the near-wellbore of the horizontal well.

5.5.2 Plover Lake Field

The next example is a 10-well group in Plover Lake Field, all from a 2.5 km^2 area (Section 5 in the Township). This field is similar to the Luseland Field in its basic reservoir parameters, except for somewhat higher oil saturations in Plover Lake.

The major points that can be made from this field are worthy of separate and clear statement:

- All the vertical wells are sand producers (CHOPS wells).

- All the horizontal wells exclude full formation sand production (however, some fines may migrate into the wells through the slotted liners).
- Every vertical well has been a better oil producer than even the best of the horizontal wells.
- Attempts to improve production in the horizontal wells by steam injection resulted in marginal, but not economically justified production improvement.
- The horizontal wells in almost all cases produced more water than the vertical wells.
    - The WOR for the vertical wells is ~0.7.
    - The WOR for the horizontal wells is ~4.0.

Table 5.4 contains further details of the behavior of the vertical and horizontal wells at Plover Lake. As of December 1998, all the horizontal wells had been shut down because of massively declining oil production and high water cuts. Because the vertical CHOPS wells have been on production for much longer times, it is also valuable to examine the typical production rates. These values over the life of the wells are about 1050 b/mo for the verticals, and 1333 b/mo for the horizontals. However, these figures alone are insufficient for a rational comparison because in the period 1994-1996, the vertical wells were placed on CHOPS production after 12-13 years on slow oil production with only small amounts of sand ingress. In other words, the vertical wells all have production histories similar to Figure 5.3b. (Care is necessary in comparisons!)

Table 5.4: Section 5, Plover Lake Field Wells

Well No	Months on production.	Produced oil, bbl	Produced water, bbl	Oil rate, b/mo	H_2O rate, b/mo
013-5	214	217223	189926	1015	887
014-5	209	227690	134091	1089	641
015-5	213	181818	105223	853	494
016-5	216	265989	189854	1231	878
91^5-5	33	38546	95213	1168	2885
91^8-5	45	46706	345401	1037	7675
91^9-5	44	41477	209959	942	4771
92^9-5	91	157106	349923	1726	3845

91^12-5	60	84296	118215	1404	1970
92^12-5	36	67249	80682	1868	2241

Figure 5.12 contains a plot of water and oil production from these wells.

5.5.3 Cactus Lake Field

Cactus Lake Field in Saskatchewan is just east of the Alberta border about 110 km south of Lloydminster. Production is from unconsolidated fluvial channel sands ranging from 22 to 30 m thick, with 60 to 90% of net pay in the interval. The channel is 1.5-2 km wide and is referred to as the McLaren Formation, the uppermost of the Cretaceous Mannville Group heavy oil zones. On average it is medium grained, but there are many fine-grained oil-free streaks in the upper 20% of the reservoir, and several in the lower 50% as well. Because these are channel sands, there are lag deposits comprising coarse-grained sands and gravels in the lower part; all factors being equal, one would expect the permeability of lag gravel deposits to exceed 5-8 Darcy.

This McLaren Formation channel sand has a permeability of 2-5 Darcy reported average; in the pay zones, the sand is saturated (S_o ~0.85) with ~5000 cP heavy oil. There are a few small free gas caps locally, and in the bottom of the channel there are zones of free water. However, both the small gas caps and the water zones are partially isolated from the central richer pay zone by bands of lower permeability deposits.

The eight horizontal wells listed in Table 5.5 are all 1000-1200 m long, spaced 200 m apart. The wells were intended to be the upper wells of a double-well, steam-assisted gravity drainage system, but initial tests on the wells seemed to justify a non-thermal production phase. The horizontal wells were drilled in the upper part of the formation to keep them farther away from active bottom water in order to operate the gravity wells under small gradients, and thereby achieve higher production rates.[37]

The single vertical well is in the same 2.5 km^2 area as the eight horizontal wells, and is operated

[37] In the decade 1990-2000, as gravity drainage processes slowly became recognized as viable and valuable alternatives to processes dominated by Δp, many operators implemented horizontal wells. Yet, it is obvious that they often failed to understand the basic physics responsible for gravity flow (density differences and countercurrent

as a CHOPS well.

Table 5.5: Sections 14 and 15, Cactus Lake Field Wells

Well No	Months on production	Produced Oil bbl	Produced Water bbl	Oil rate b/mo	H_2O rate b/mo
010-15	140	287070	214365	2050	1531
91^8-14	45	23683	1843	526	40
92^8-14	69	43523	162626	630	2356
91^9-14	70	301741	402400	4310	5748
92^9-14	70	265037	890810	3786	12725
91^5-15	71	77684	121625	1094	1713
92^5-15	71	82303	28613	1159	403
91^12-15	54	248665	750055	4604	13889
92^12-15	71	401844	491504	5659	6922

Figure 5.13 contains a plot of water and oil production from these wells.

Cactus Lake Field is one of the most successful cases of horizontal wells in heavy oils with viscosities greater than 1000 cP. Nevertheless, the single vertical CHOPS well has proved to date to be better overall than four of the horizontals in terms of total oil production, but not as good as the other four wells. It is important to remember, however, that vertical wells are far cheaper to drill and to operate in terms of intervention activity costs. In addition, the vertical CHOPS well has produced at a more favorable WOR than the four best horizontal wells.

5.5.4 Evaluation of Non-Thermal Horizontal Wells vs Vertical CHOPS Wells

Aziz et al.[xxix] try to explain prediction difficulties for horizontal wells in terms of mesh refinement in numerical modeling efforts, as well as a lack of sufficiently refined geological models. Their arguments are unconvincing.

Beliveau compared horizontal wells with offsetting vertical wells in an effort to explain more

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flow) and implemented approaches that tended to be inefficient or misguided. Thus, failure to realize the goals of well drainage in density-dominated gravity flow systems in this era is not necessarily proof (or disproof) of concept.

clearly the risk involved in horizontal well assessment.[xxx] He noted that for heavy oil there was a very wide scatter of horizontal well performance as compared to that of offset vertical wells. The four cases presented in this Chapter seem to reinforce this observation. The writer believes that horizontal wells are not "inherently" more scattered in terms of their production performance, although a long horizontal well clearly has a greater chance of being close to active water and therefore is undoubtedly more prone to coning if it is operated as a Δp-dominated well (see previous footnote). Rather, the writer contends that operators still do not understand fully the dominant physical processes involved, and therefore make use of horizontal wells in many circumstances where they are not advisable.

These articles, and many others based on conventional interpretations and simulations, fail to address the issue of fundamentally different production mechanisms in vertical CHOPS wells and in horizontal wells without sand production. CHOPS wells produce sand and therefore benefit from the aforementioned production enhancement mechanisms, whereas horizontal wells are not in general designed to produce sand. These CHOPS mechanisms (sand liquefaction, foamy oil drive, etc.) are not incorporated into the reservoir simulators currently in use, therefore a rational evaluation of their impact using production predictions based on physical processes is not available to the planning engineers. Rather, the only reasonable predictive approach at present is prediction by analogy: using similar cases to project likely behavior of the case being studied. For this approach to be effective, the planners must understand the physics in depth so that proper analogies can be developed. In general, this has not been done, and many failures or projects of low profitability have resulted.

Nevertheless, other successful horizontal wells in Pelican Lake, Amber Lake, and adjacent areas in the Wabiskaw deposit have produced reasonable amounts of oil in the range of 1000 cP viscosity from thin zones, on the order of 4-7 m thick, and without active bottom water. Given the data presented to date, it is clear that a more practical methodology is needed for well evaluation in heavy oil reservoirs. The following practical methodology is suggested:

- Carry out a comparison to other heavy oil reservoirs, particularly in Canada where the knowledge base is vast, compared to other areas in the world. This comparison must seek to identify and establish the best analogues available in the data bank.
- If the reservoir is truly an unconsolidated (uncemented) sandstone with no free mobile

water zones in the reservoir interval, CHOPS may be a viable and profitable method.

- If deemed suitable, CHOPS trials should be attempted in virgin zones that have not been depleted or treated with another technology (e.g. steam injection, steam drive).
- If the reservoir sandstone is slightly cemented, technologies other than CHOPS are more likely to succeed. Nevertheless, if the cementation is weak, a period of deliberate sand production may be beneficial for well productivity because of the enhanced permeability zone generated.
- If CHOPS appears feasible, it is reasonable to test field production behavior with several pilot wells before adopting field wide application. A minimum of four of five test wells seems reasonable before a field development decision is made.

A CHOPS pilot test requires one or two wells, and is likely to cost about one-quarter to one-half of a horizontal well test. If CHOPS is feasible, there is little economic incentive to pursue more expensive solutions, such as thermal stimulation. On the other hand, if properly executed tests show that CHOPS is not feasible, evaluation of alternative heavy oil production approaches must be carried out. The alternative options at this time are:

- Thermal approaches using high Δp techniques such as cyclic steam stimulation, although this group of technological alternatives requires excellent reservoir conditions and has its own set of operation difficulties and costs. (They are in general not recommended.)
- Gravity-based thermal methods, such as SAGD, VAPEX, or some combination of the two.
- Non-thermal approaches involving long horizontal wells. This is the favored production method in Venezuela, where, with installation of many laterals, it has proven successful economically, but is likely to result in only 10-12% OOIP recovery.[38]
- Pressure pulse flow enhancement using horizontal producers and vertical excitation wells can be used with most technologies to enhance flow rates or to help stabilize water injection in heavy oils.

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[38] The Venezuelan operators will be forced into assessing other technologies in the future to extract more value from their reservoirs. Realistically, their options at present appear to be CHOPS, pressure pulsing, SAGD, or VAPEX.

Included in the Appendix III is an article comparing Canadian and Venezuelan experience, and the reasons why the Venezuelan projects have pursued multi-lateral horizontal wells rather than exploring the possibility of CHOPS production. However, it appears that the upper strata in the Faja del Orinoco sequence (with ~30-40% of the resource) are not suitable for the long horizontal well approach, are too thin for thermal methods, and therefore represent large potential applications for CHOPS.

5.6 The Mathematical Simulation of CHOPS

5.6.1 Non-Conventional Processes in CHOPS

Mathematical modeling (numerical simulation) of CHOPS for predictive purposes is particularly challenging because CHOPS involves a series of processes that are not conventionally addressed in reservoir simulation:

- There is a solid-to-liquid phase transition (liquefaction) of the matrix;
- Stresses and stress changes play a major role in sand destabilization and liquefaction;
- Conventional assumptions of phase saturations (i.e., based on compositional simulation and thermodynamic equilibrium) are not justified;
- Much of the transport process is dominated by slurry flow *in situ*, rather than by diffusional (Darcian) mass transport alone;
- Geometrical boundary conditions (altered zone size) change continuously;
- Far more physical parameters are needed than in conventional simulation, in particular, many geomechanical and slurry parameters are needed as well as Darcian fluid flow parameters;
- General uncertainty remains high regarding the appropriate value of physical parameters and their relationships because of sampling and testing difficulties; and,
- The processes involved (phase transition, slurry behavior…) are invariably strongly non-linear and coupled, making it impossible to write simple behavioural laws.

Nevertheless, a decade of efforts to develop simulation of CHOPS has achieved substantial progress: adequate simulation models are now available[xxxi], and progress continues. The major physical processes are now discussed, but such a discussion will necessarily suffer from a lack of detail. Delving into the detailed physics and mathematics of CHOPS analysis requires reference to the literature, and a considerable amount of dedicated analysis.

5.6.1.1 Liquefaction of Sand

Sand liquefaction is a phase transition from a solid to a liquid. Such a phase transition accompanies all CHOPS processes. In this phase transition, porosity plays the same role as temperature in the melting of a solid. In fact, in a rigorous treatment, porosity must be treated as a thermodynamic state variable in a manner similar to temperature.[xxxii,xxxiii] Unfortunately (unlike in melting of a single phase), there is not a specific "melting porosity" that defines the sudden jump from a 30% porosity solid to a 90% porosity liquid. The process is much more complicated, even more complicated than the melting of an alloy of different metals. The liquefied state is defined as the condition that exists when grains do not form a continuously linked array; i.e., liquefaction implies that $\sigma' = 0$ and $\sigma = p$.

The reservoir is at a porosity of ~30%; the outflow at the wellhead contains ~1-10% sand and substantial quantities of free gas, thus it has a porosity >90%. In changing from 30% to >90% porosity, the "system" in the reservoir must pass through all intermediate porosities, and the changes in physical properties are accordingly huge.

Figure 5.14 is an attempt to show how the dominant physical processes change with porosity. To achieve the liquefaction porosity of ~50%, the sand fabric must dilate; after liquefaction, a dense slurry exists where substantial internal energy dissipation takes place through collisions and sliding between grains, even though the grains are not in a sufficient state of contact to transmit compressive matrix stresses. After more dilution with liquid (and perhaps some gas bubbles), a dilute slurry is generated; at this point, grain collision energy dissipation becomes negligible compared to the level of viscous energy dissipation in the fluid phase. Even neglecting the complication of a dispersed bubble phase in the slurry, one phase transition and three or four separate regimes exist in the porosity domain encountered in CHOPS (elastic deformation, plastic deformation, the phase transition, dense slurry flow, dilute slurry flow).

Dense sands do not spontaneously liquefy; under stress, the grains are held in a three-dimensional array with high contact forces (normal and shear forces) that cannot be overcome by seepage forces. This fabric must be perturbed and dilated, which requires a large reduction in confining stress and an increase in shear stress. Because all of these changes are linked to the mechanical state and response of the reservoir fabric, geomechanics factors are of primary importance up to the point of full liquefaction; thereafter, hydrodynamics become dominant.

5.6.1.2 The Enhanced Permeability Zone

Near the wellbore, where sand is liquefied, permeability cannot be defined; in the ~45% porosity zone, it exceeds 15-20 D for a 100-150 μm sand; where intact sand still exists in the reservoir, a typical permeability is 1-4 D. Perhaps of equal importance, as the reservoir sand dilates, pore blockages (clays, asphaltenes, gas bubbles) have less and less effect on the permeability.

If a compact growth zone exists, an average permeability linked to porosity ($k \propto \phi^n$) can be defined, but this implies that the mathematical simulation gives a reasonable estimate of porosity and that the porosity is homogeneous (not channeled) at the same physical scale of the mathematical discretization used.[39] These assumptions remain unsubstantiated, and are unlikely to be true. Alternatively, some simple function of radius may be used to describe physical properties around a CHOPS well (Figure 5.15). If the k-enhanced zone is highly irregular in shape (a few channels), defining a "block-averaged" permeability at an instant in the simulation process is not only a problem, the values will also change with each time step.[40]

Apparently, there is no easy way of determining the permeability because of the non-homogeneity of the region surrounding the well and the general uselessness of well tests. Some work[xxxiv] shows that a simple model can capture most of the permeability enhancement effects. Sensitivity analyses show clearly that although a model with a continuous change in permeability ($k = f(r)$) gives time derivative plots that are quite different than a skin model ("skin" is a zero-thickness flow impedance zone), results can be approximated by a multiple zone composite model. However, each additional zone in a composite model has two additional unknowns, and once the number of zones exceeds two the number of unknowns becomes so great that any

[39] In general, mathematical reservoir simulation involves dividing up the zone to be analysed into a number of "elements" (or nodes or particles). These elements can be of various sizes, but it is assumed that within each element, the system is homogeneous (but not necessarily isotropic or linear).

[40] Numerical simulation is carried out over a time period, and calculations are performed sequentially as time "advances". This may be referred to as "time discretization".

solution by inversion or curve matching is no longer realistic. For example, two cylindrical zones around a well give eight total unknowns: three compressibilities, three permeabilities, and two radii; performing a statistical analysis on well performance to find these values in the case of CHOPS wells is essentially a futile exercise because of the lack of constraints on the process. To the writer's knowledge, all such efforts have failed.

5.6.1.3 Foamy Oil Behavior

The physics of foamy oil has been examined in detail in recent years.[xxxv,xxxvi,xxxvii] Many scientific and technical issues that are currently being in laboratories and research groups in Alberta and Saskatchewan[41] will gradually affect and improve the mathematical simulation of foamy oil behavior *in situ.* These include:

- Obtaining kinetic exsolution rate data for CH_4 from cold heavy oils (an extremely challenging experimental task).[xxxviii,xxxix]
- Verification of the hypothesis that a continuous gas phase does not develop in CHOPS. Otherwise, another explanation for the constant GOR values over many years of production will have to be developed.
- Understanding if the bubble induction zone is physically linked to a zone of sand dilation (i.e. perhaps bubbles can be created only when sufficient new local volume is created by the dilation process).
- Quantifying the effect of bubbles on sand permeability relative to oil flow.
- Confirmation and quantification of various other physical processes around CHOPS wells *in situ*.

5.6.1.4 Slurry flow

The mechanics of dense and dilute slurries of solids is a complex issue that is not yet resolved for high concentration slurries where internal energy dissipation through collisions can take place.[xl]

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[41] In the period 1998-2002, efforts to understand foamy oil behavior have also been initiated in private corporations, including TotalFinaElf, BP, ExxonMobil and ConocoPhilipps. As interest in heavy oil continues to increase, these efforts will be expanded.

It will not be discussed in detail here, but the subject has been studied in the laboratory and from a theoretical point of view.[xli]

5.6.2 Conventional Approaches to Simulation

Conventional simulation without stress coupling attempts to account for the effective stress change ($\Delta\sigma'$) effects through prediction of volume changes (ΔV) using compressibility (C_m): $\Delta V = V \cdot C_m \cdot \Delta\sigma'$. To use this fundamental and correct relationship in practical simulation, a further assumption is made that $\Delta\sigma' = -\Delta p$ (where the change in pressure is calculated as part of the mathematical simulation). This is a flawed assumption; a change in pressure does not lead to the identical and opposite change in effective stress; the relationship is more complex, and must be calculated in a rigorous manner using the compressibilities of the phases.

Moreover, in all conventional flow analysis (e.g. the basic equations of Theis, Muskat and Gringarten), it is implicitly assumed that boundary stresses remain constant: $\Delta\sigma$ terms do not even arise in the formulation of flow equations. However, consider what happens near a vertical well. As the well is produced, the pressure near the wellbore drops, therefore σ' increases, and a small volume change must occur. This means that the rock near the wellbore shrinks slightly, but since the overburden rocks have rigidity, the vertical total stresses are redistributed. The total stresses are clearly not constant; hence the common assumption $\Delta\sigma' = -\Delta p$ is immediately invalidated. Analyses of this effect[xlii,xliii] show that errors in flow rate predictions are as high as 50%, and that the errors are dominantly during the period of early flow, which is usually the domain that is analyzed in reservoir evaluation. Furthermore, one may note that stress arching[42] during early depletion, even during extended production tests, can delay the onset of massive compaction. (This was the case for the Ekofisk Field in the North Sea: extended production tests failed to identify compaction, and the necessary platform height to resist wave action over 50 years was thus underestimated seriously, requiring expensive platform jack-up activity costing about US$500,000,000 in the late 1980's.)

[42] The redistribution of stresses so that they flow "around" a zone is often referred to as stress arching, and this behavior is deliberately exploited in many earth structures, as well as in stone cathedral arches which transmit stresses from the roof to the pillars to the foundations.

Other assumptions inherent in conventional simulation mentioned above should be revisited as well. In particular, the standard assumption of local equilibrium (the basis of "compositional modeling") is probably insufficient for heavy oils because of the extremely slow diffusion rates: a kinetic model is needed. In a kinetic model, the rate of gas evolution from the liquid phase is analyzed at each time step so that the amount of free gas at any time can be calculated.

In many analyses, attempts to "history match" the behavior of laboratory sand packs are carried out using conventional mathematical simulators. However, these exercises usually involve many "free" or ill-defined parameters, or else the user will fix parameters (e.g. solubilities, gas contents, bubble points, relative permeabilities, compressibilities, etc.) at physically unreasonable values in order to improve the statistical fit to the real data.[xliv,xlv,xlvi,xlvii] Can these efforts using freely adjusted parameters and laboratory processes in which the boundary conditions are totally different than the *in situ* case be of value in design? For this to be the case, there must be direct and useful relationships with the *in situ* mechanisms and the large-scale system alterations that take place during CHOPS. If a conventional simulator is used, processes such as the growth of a compact or a channel zone cannot be included, except empirically in an effort to "fit the history" or "match the data". For example, it is possible to increase the radius of a high-k zone purely as a function of the amount of sand produced from the CHOPS well. This function relating radius and the volume of sand produced is arrived at purely empirically, and is based on the assumption that this is indeed the dominant physical process in CHOPS.

Is it valid to attempt to history match CHOPS in specific cases if several first-order physical processes such as the effect of stress, sand dilation and liquefaction, and slurry flow are absent from the model? Furthermore, is it valid to use this "calibrated" model to predict the future behavior of the well or other wells in the field? The answer is not at all clear, but the direction of simulation is clearly away from "calibrated" conventional simulation to more rigorous coupled geomechanics simulation, based on physics, rather than specious relationships.

5.6.3 Stress-Flow Coupling and Physics-Based Modeling

Attempts to develop analytical and semi-analytical solutions for CHOPS well production behavior are hampered by the massive non-linearities and the complexity of the processes. Nevertheless, for compact growth and channel models, considerable progress has been achieved (see articles by Geilikman). These models essentially had their origins in early attempts to understand stress, dilation and yield around circular openings.[xlviii,xlix,l] The sand flux models are all based on introducing aspects of stress, shear-induced dilation, and concomitant permeability increases, with necessary simplifications such as 2-D axisymmetric geometry, ideal elastoplasticity, local homogeneity, limited provision for slurry flow energy dissipation, and so on. In the simplest case, stress changes and flow behavior are expressed in vertically axisymmetric equations that assume plane strain in a tangential (θ) direction; i.e., overburden stress redistribution is not explicitly incorporated. In this case, flux equations reduce to quasi one-dimensional forms.

The Geilikman family of models links the drawdown rate of the well to the magnitude of sand flux. His model "predictions" of an initially high then declining sand flux, combined with a slowly increasing then slowly declining oil flux, correspond with observed field behavior. However, no semi-analytical model can simulate the initiation of sand liquefaction and make an *a priori* prediction of sand flux and oil rate increases based solely on a set of initial conditions, material parameters, and constitutive laws. Many assumptions have to be made, and the models must be repeatedly calibrated to sand production history to help develop realistic predictions.

Recent work is moving toward more general numerical simulation based on a coupled stress-flow formulation solved with the finite element method.[li,lii,liii,liv] These methods are far too complex to discuss here, but it should be noted that most aspects of the CHOPS process, with the exception of the slurry flow component, are now being incorporated into modeling on a relatively sound physical basis. There is yet a considerable distance to go to achieve full simulation capability of CHOPS processes, and substantial uncertainty will always remain because of the large number of poorly constrained variables in these complex processes.

Finally, it is worthwhile noting that issues such as stress arching (stress redistribution), fabric evolution (changing porosity and permeability during dilation and liquefaction) and slurry flow of a mixture of bubbles, liquids and sand grains can be studied using the discrete element method, where individual particles are allowed to interact and fluid flow forces can be included.[lv] These methods promise to generate insight into issues such as capillarity changes and destabilizing of sand arches, an extremely difficult problem that is not amenable to continuum mechanics approaches. However, these are physics-based models, not design models that use volume averaged properties, and they are not likely to be used for mathematical reservoir simulation.

5.7 CHOPS or Not?

The ingress of sand into an oil or gas well during production increases the flow rate of formation fluids (oil, water, gas) by reducing impediments to flow through the pore throats of the medium that may be caused by near-wellbore blockages, and by the concomitant formation and growth of a high permeability zone around the well. Furthermore, production technologies based on sand ingress eliminate the sand exclusion methods such as sand screens, gravel packs and filters that invariably impair fluid production rates and are costly to install and to maintain.

During evaluation of potential heavy oil operations in unconsolidated and poorly consolidated sandstones, sand influx technology should be evaluated. This sand influx can be minimal, or it can be massive, and the amount of sand influx depends on the well design, the completion approach, reservoir characteristics, and production practices. The possibility of producing larger quantities of oil along with large amounts of sand arises only in the case of heavy oil development in genuinely cohesionless, unconsolidated sands. Thus, the potential for increased production versus the increased costs and risks associated with sand influx must be evaluated economically. The major elements of this assessment are:

- Will the reservoir produce sand or not?
- What is the financial benefit of CHOPS in terms of increased production rate?
- What is the additional financial benefit of not having to install and maintain sand exclusion technology such as screens and gravel packs?
- What are the costs associated with the need for sand management throughout the life of the project?
- What is the cost of the increased operational and environmental risks associated with sand ingress?
- Are there substantial additional costs related to personnel training and implementation of a sand management approach in the asset structure?

The answers to these questions can in many cases be quantified, but the only realistic cost figures available at present are from the Canadian heavy oil industry. This industry has 15 years experience with CHOPS methods and has developed a regional infrastructure to handle sand and heavy oil. In the Canadian HOB, the only economically viable non-thermal approach that has been widely used in the more viscous oils is to encourage sand influx. Years of experience have shown that if there is no sand influx, non-thermal heavy oil (>1000 cP) production rates are not economic (with very few exceptions). Also, disappointment with production rates from long horizontal wells in high viscosity oils (> 2000 cP) has restricted this approach, usually to reservoirs with less viscous crude oil (< 1000 cP). The case histories presented in this chapter are only a small number of the excellent case histories that could be developed at reasonable cost.

In many cases, the decision to implement CHOPS methods is not easily made because there is insufficient information or experience in an area to allow an empirical prediction of the increased oil rate with time. The previous sections outlined the complexities involved in mathematical modeling; although great progress is being made, simulations to predict oil rates *a priori*, or for that matter, simulations to help decide whether CHOPS is viable in the first place, are not yet in a stage of development where they can be used without substantial field-specific calibration. In such cases, where a reservoir looks interesting and has passed a preliminary set of screening criteria, study of relevant analogies and implementation of a pilot project are suggested as the best design approaches.

The Canadian experience in heavy oil development, including the rapid technological advances in areas other than CHOPS, constitutes a resource that the world oil industry can use to guide planning and to reduce unnecessary costs or prolonged investments in technologies that have already been shown to be unsuccessful or problematic in Canada.[43] Nevertheless, reservoir conditions in other areas must be carefully evaluated in this context.

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[43] This is not to imply that all heavy oil reservoirs are the same as the Canadian reservoirs. In fact, the Canadian deposits have very unfavourable conditionsin comparison with heavy oil deposits in the Middle East, China and South America. Thus, if a technology works in Canada, it is likely to work elsewhere, but the converse is less true.

Figure 5.1: Luseland Field Production History, 1982-1998

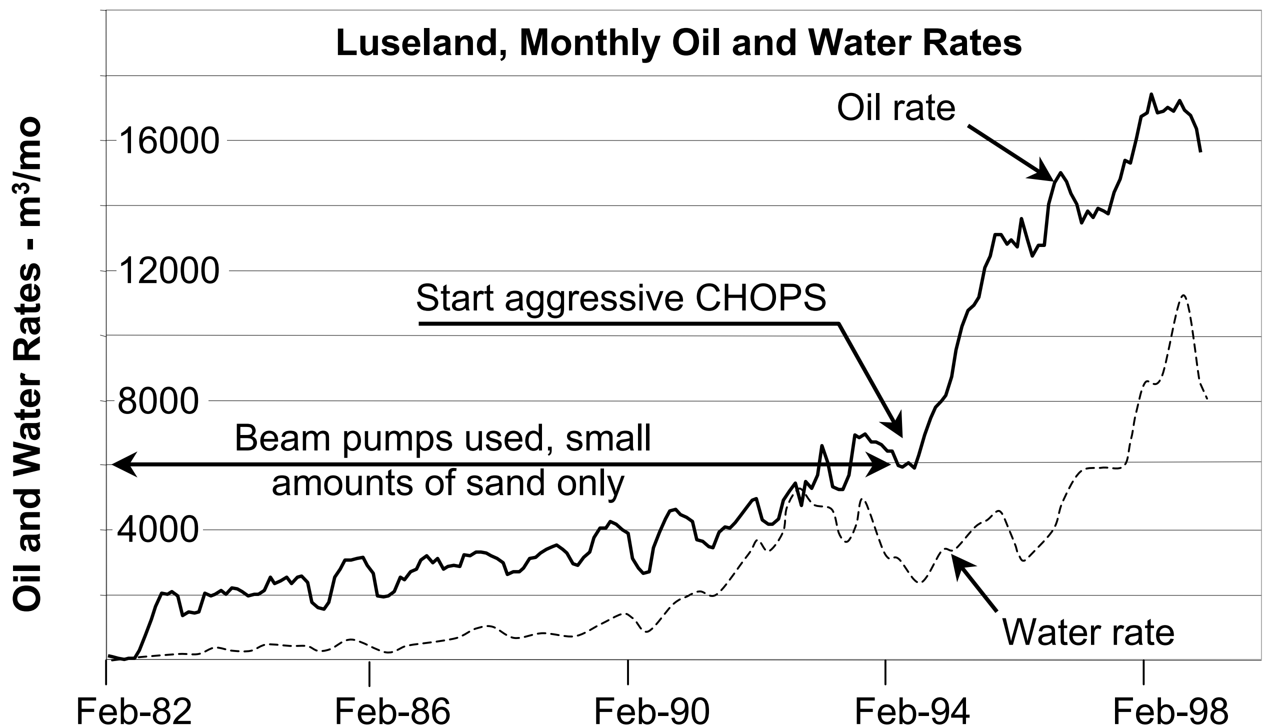
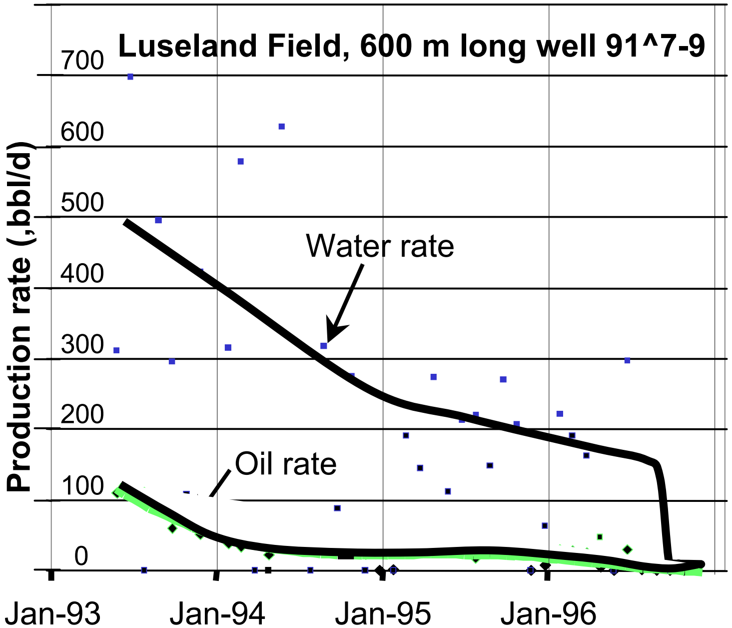
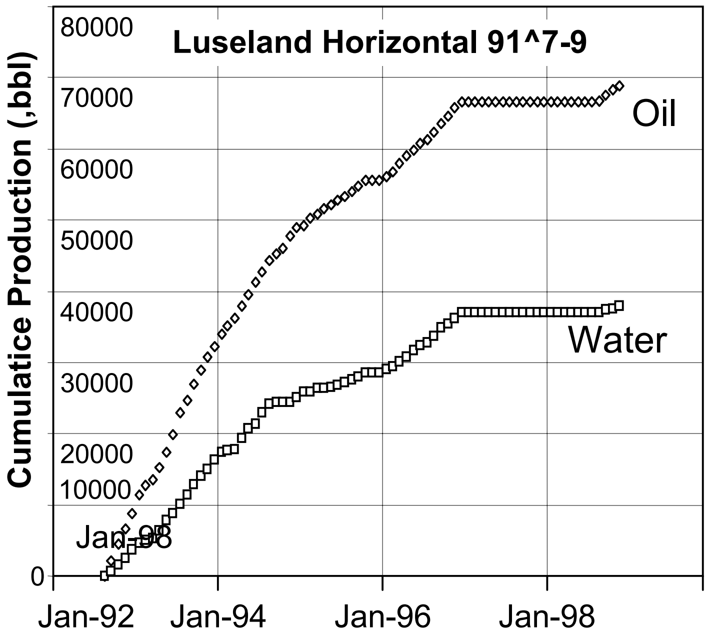


Figure 5.2: Production History for a Luseland Horizontal Well





However,in many Canadian fields with m < 1000, horizontal wells are successful (300-600 b/d), nevertheless, the daily rates tend to drop by 25-40% per year, giving short well lives.

Figure 5.3: CHOPS Well 5/4, Luseland Field

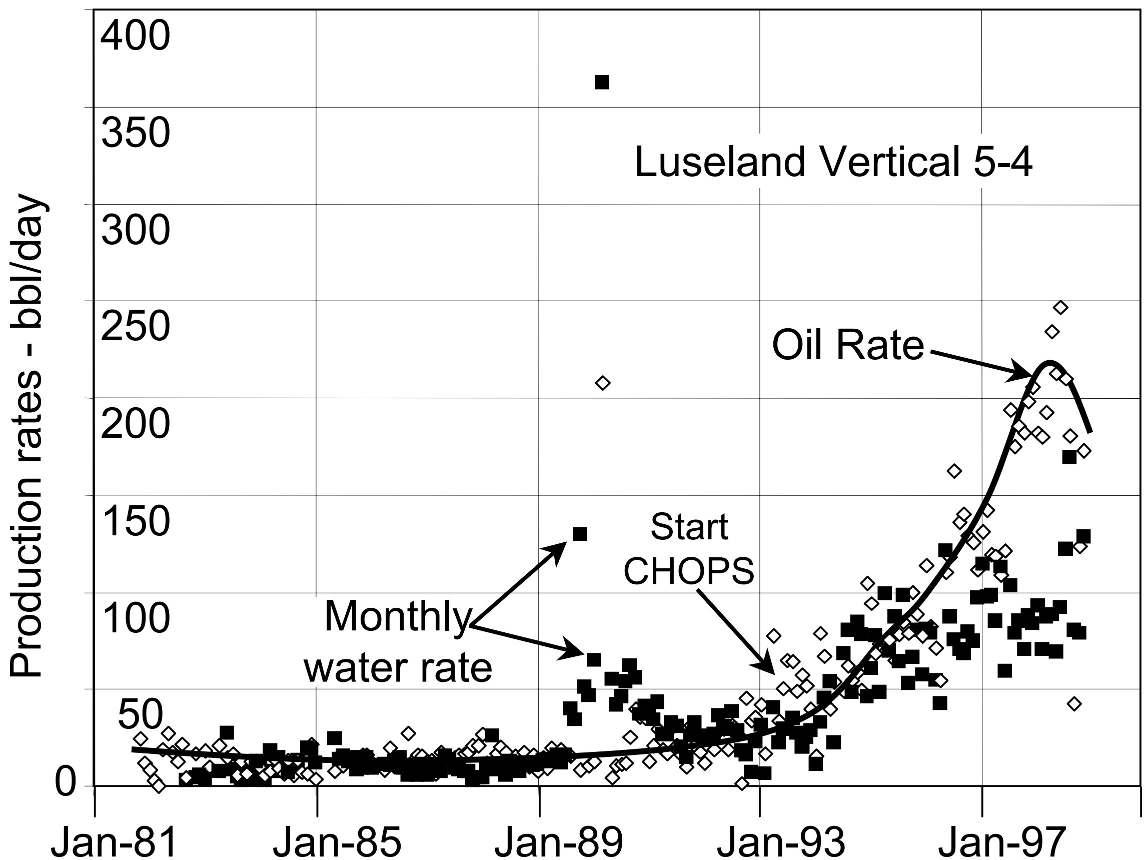


Figure 5.4: CHOPS Well 13/8, Luseland Field

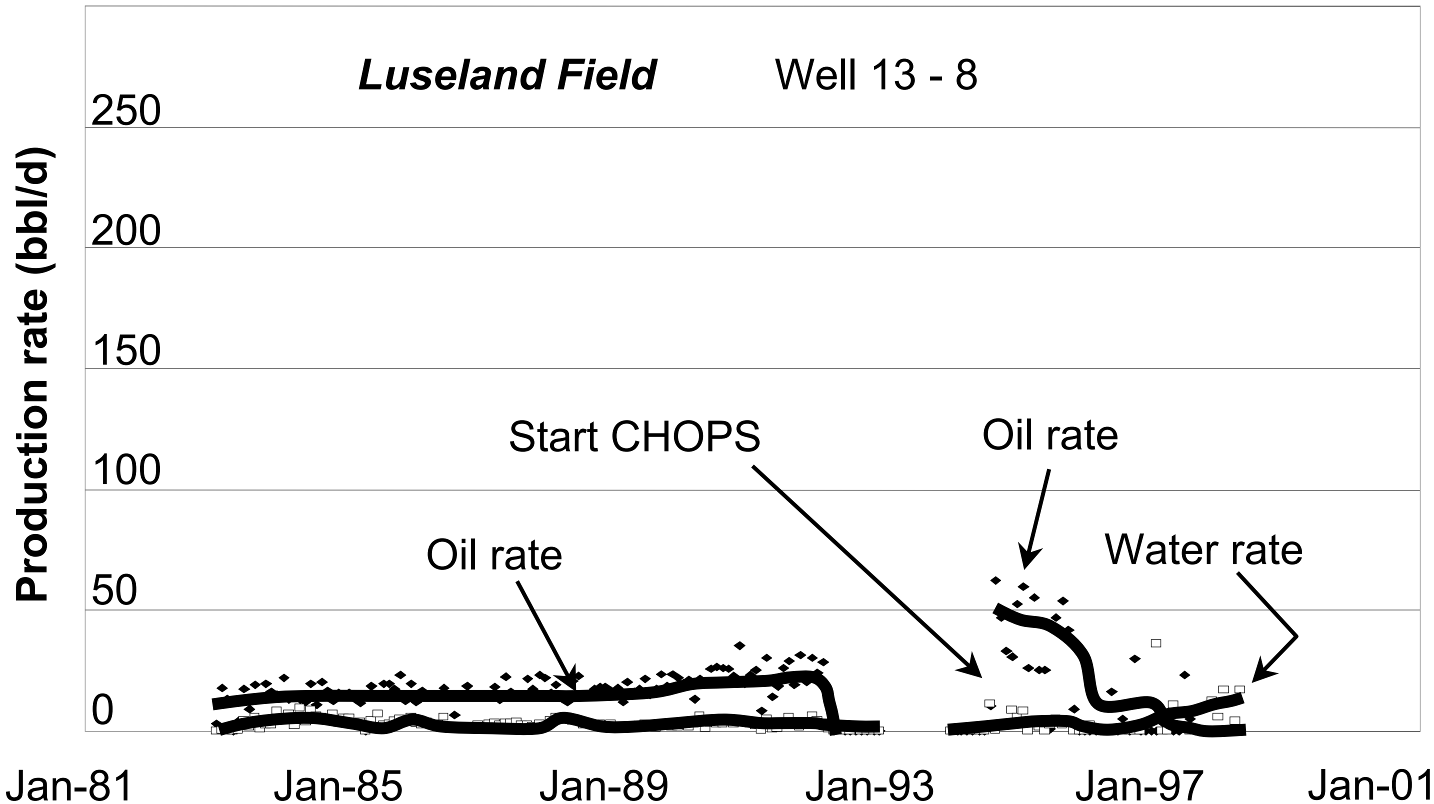


Figure 5.5: Luseland Vertical CHOPS Well 3-17

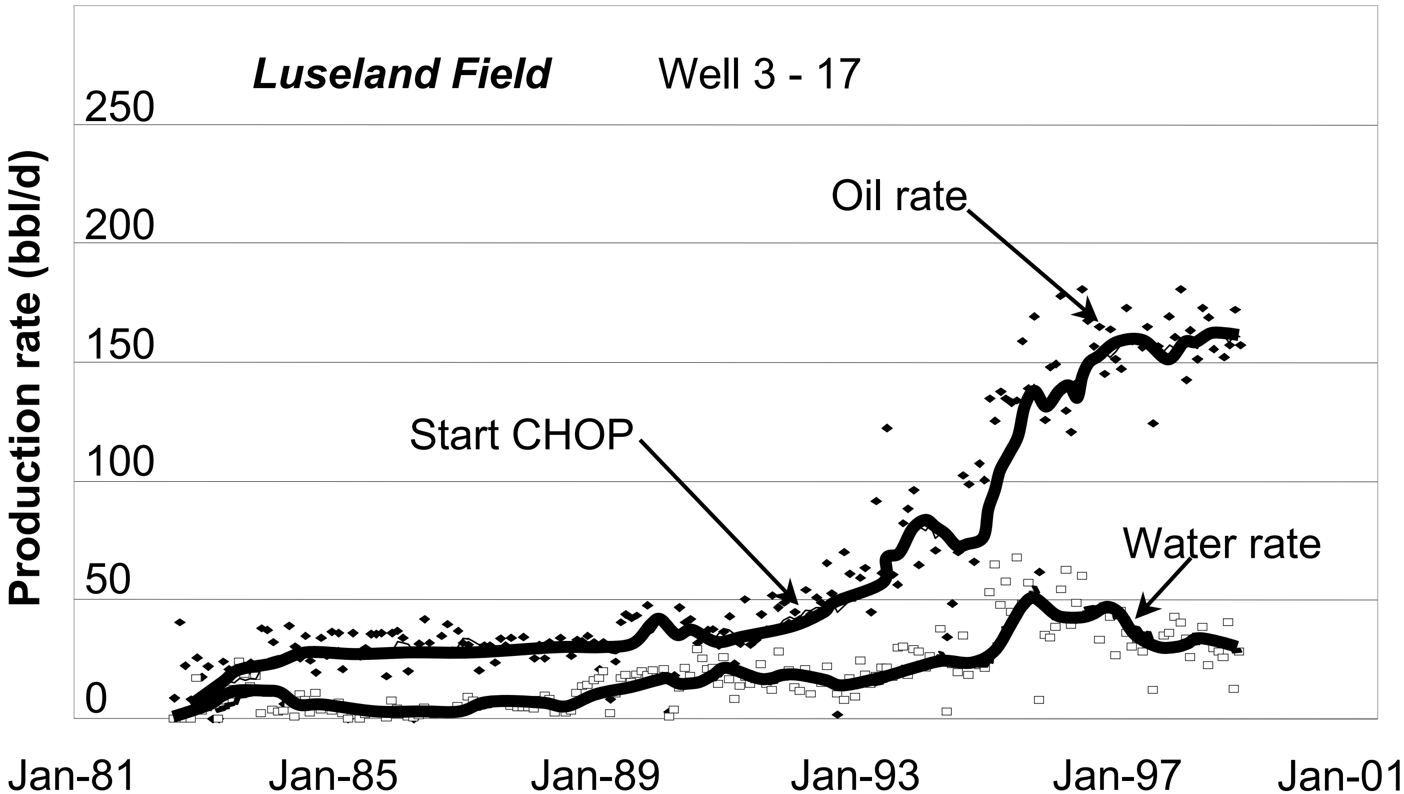


Figure 5.6: Cumulative Liquid Production, All Wells, to Dec 1998

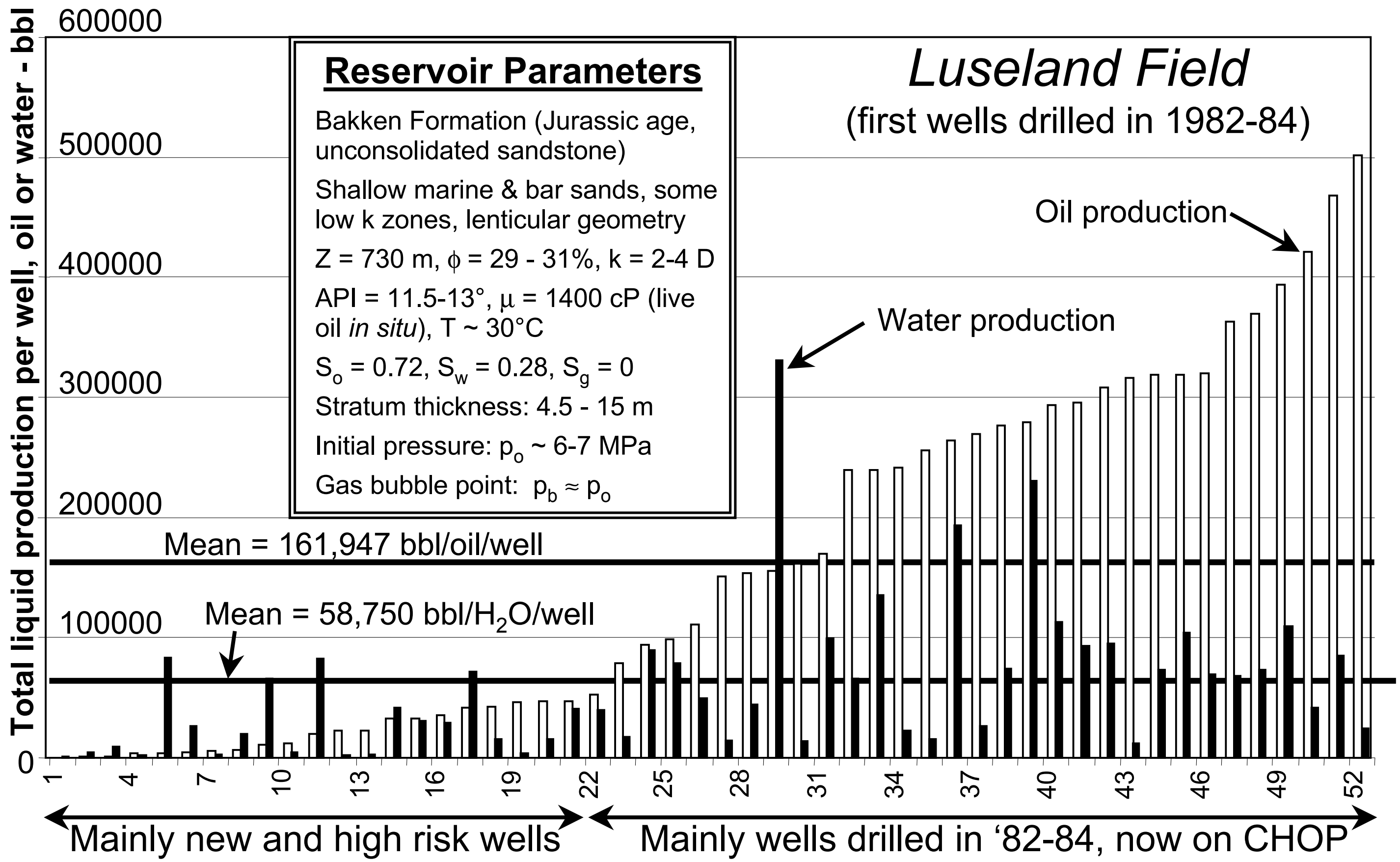


Figure 5.7: Average Monthly Oil Rate vs. Average Monthly Water Rate

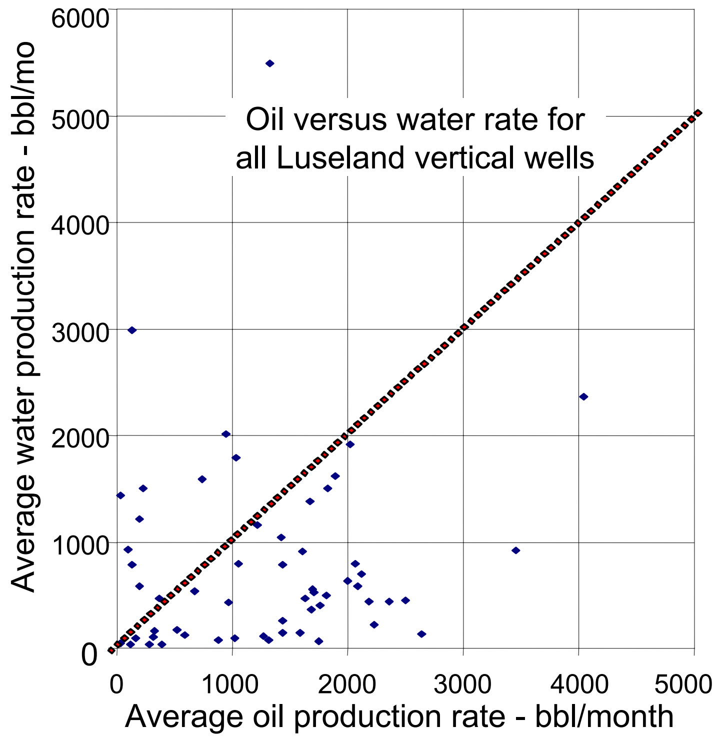
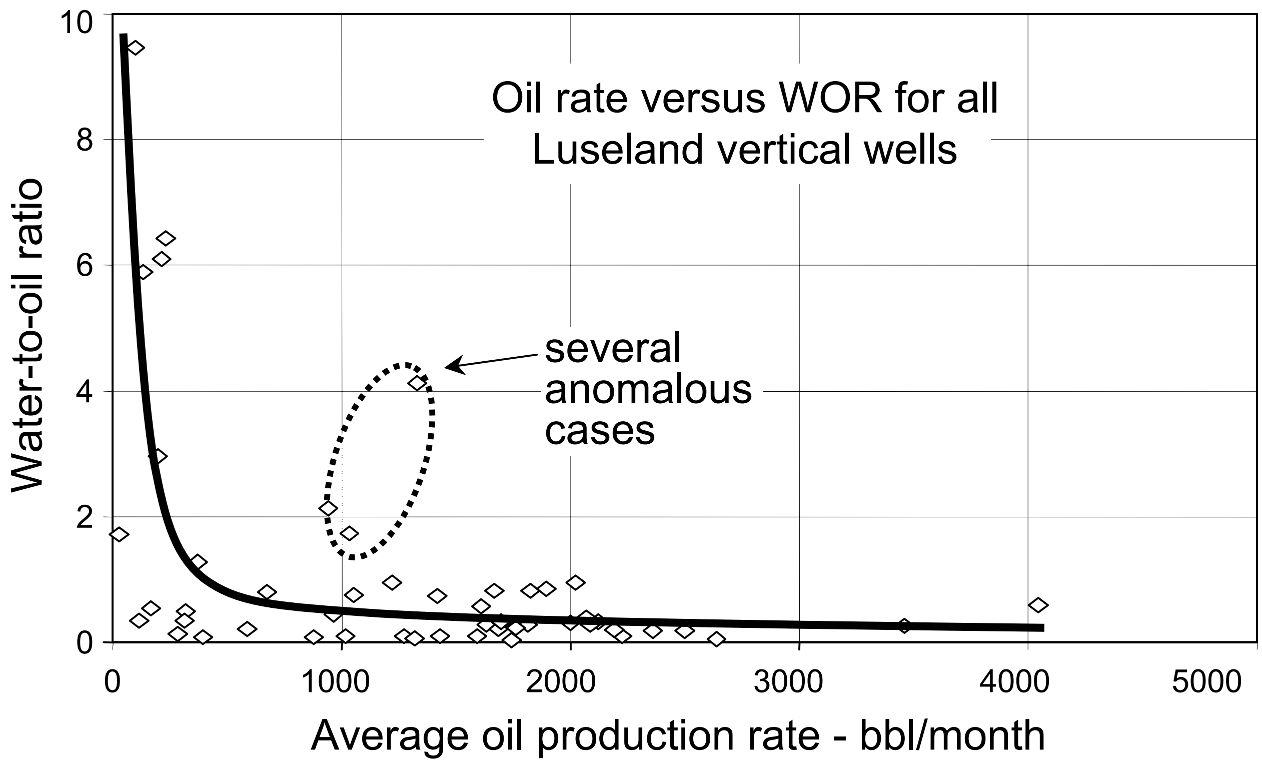


Figure 5.8: Plot of Water-Oil-Ratio vs. Oil Production Rate



The anomalous cases suggest that water flooding may be successful in some CHOPS reservoirs, and that high water rates are not necessarily catastrophic

Figure 5.9: Production from a Vertical CHOPS Well in Lindbergh Field, Alberta

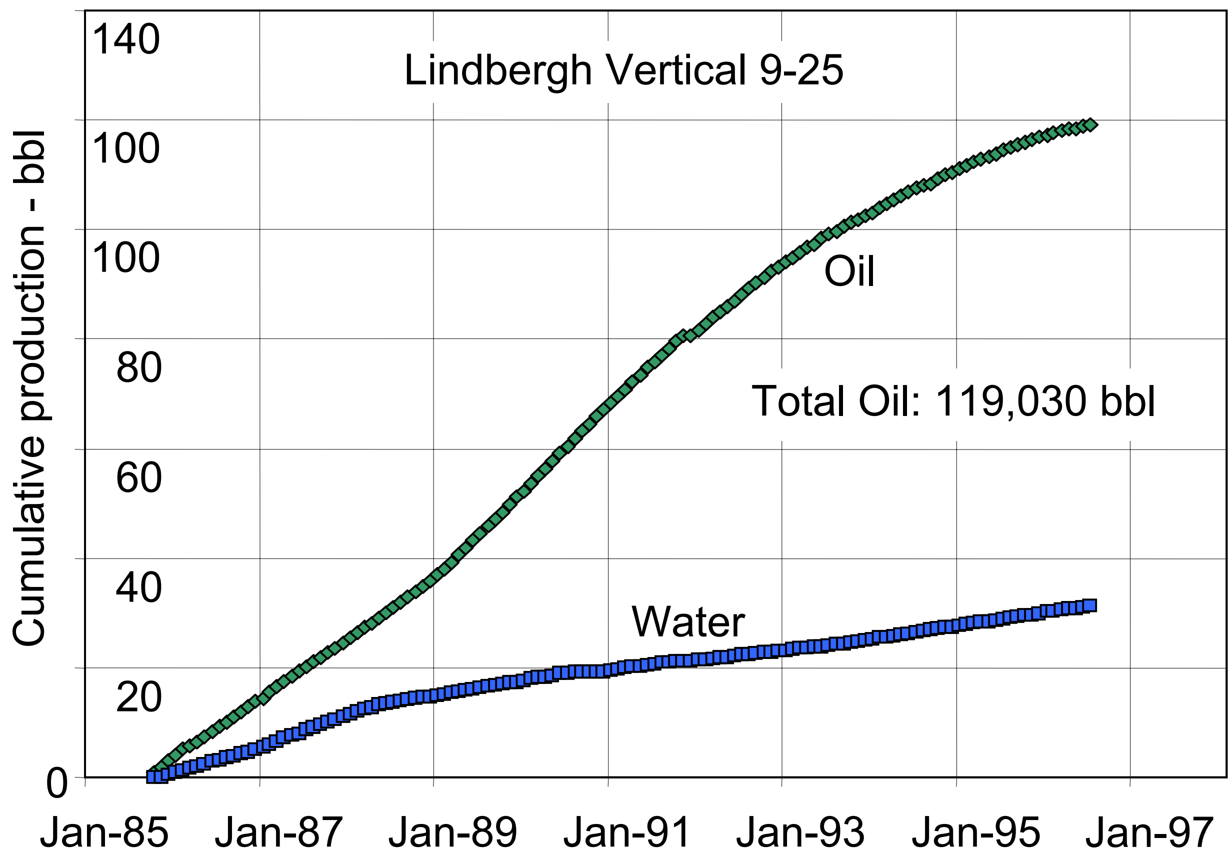


Figure 5.10: Production from a Horizontal Well in Lindbergh Field, Alberta

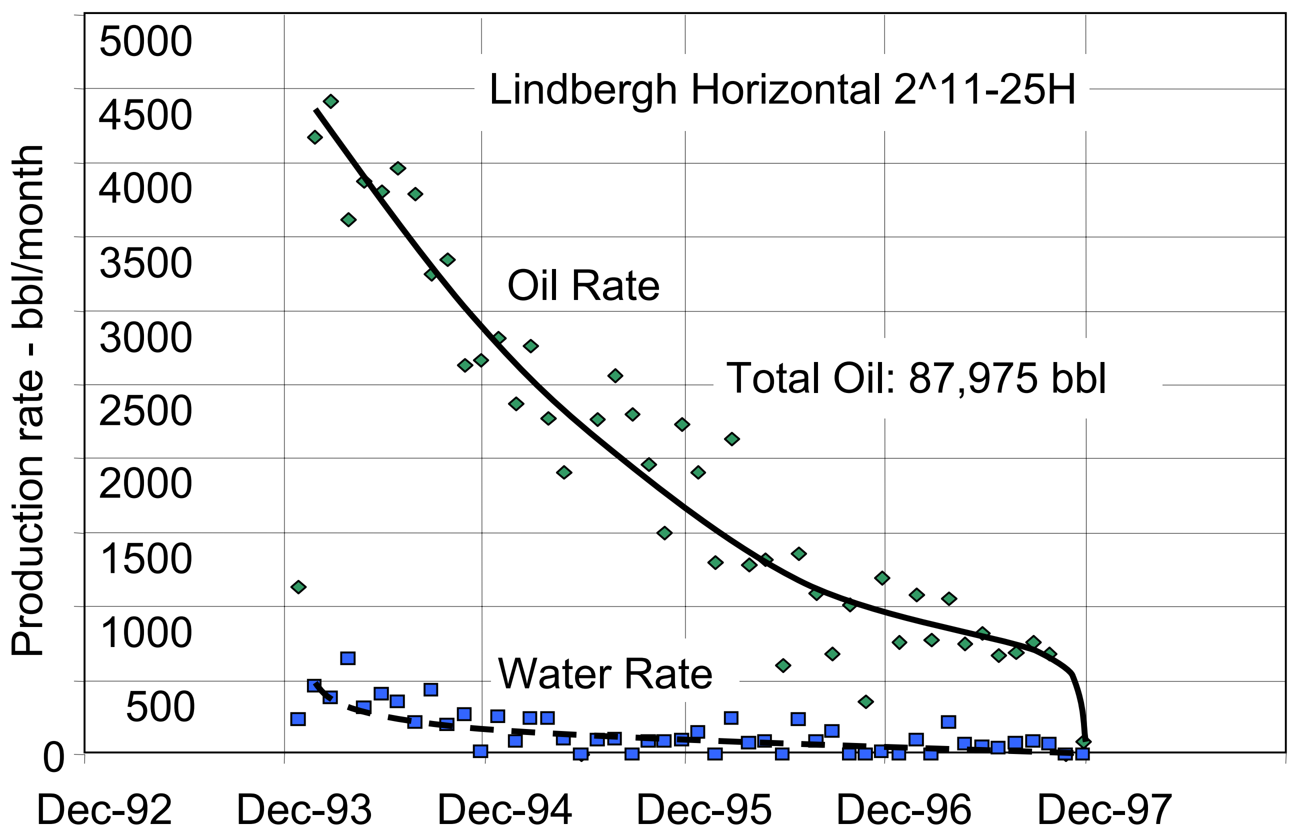


Figure 5.11: Water and Oil Cumulative Production Comparison, Lindbergh Field

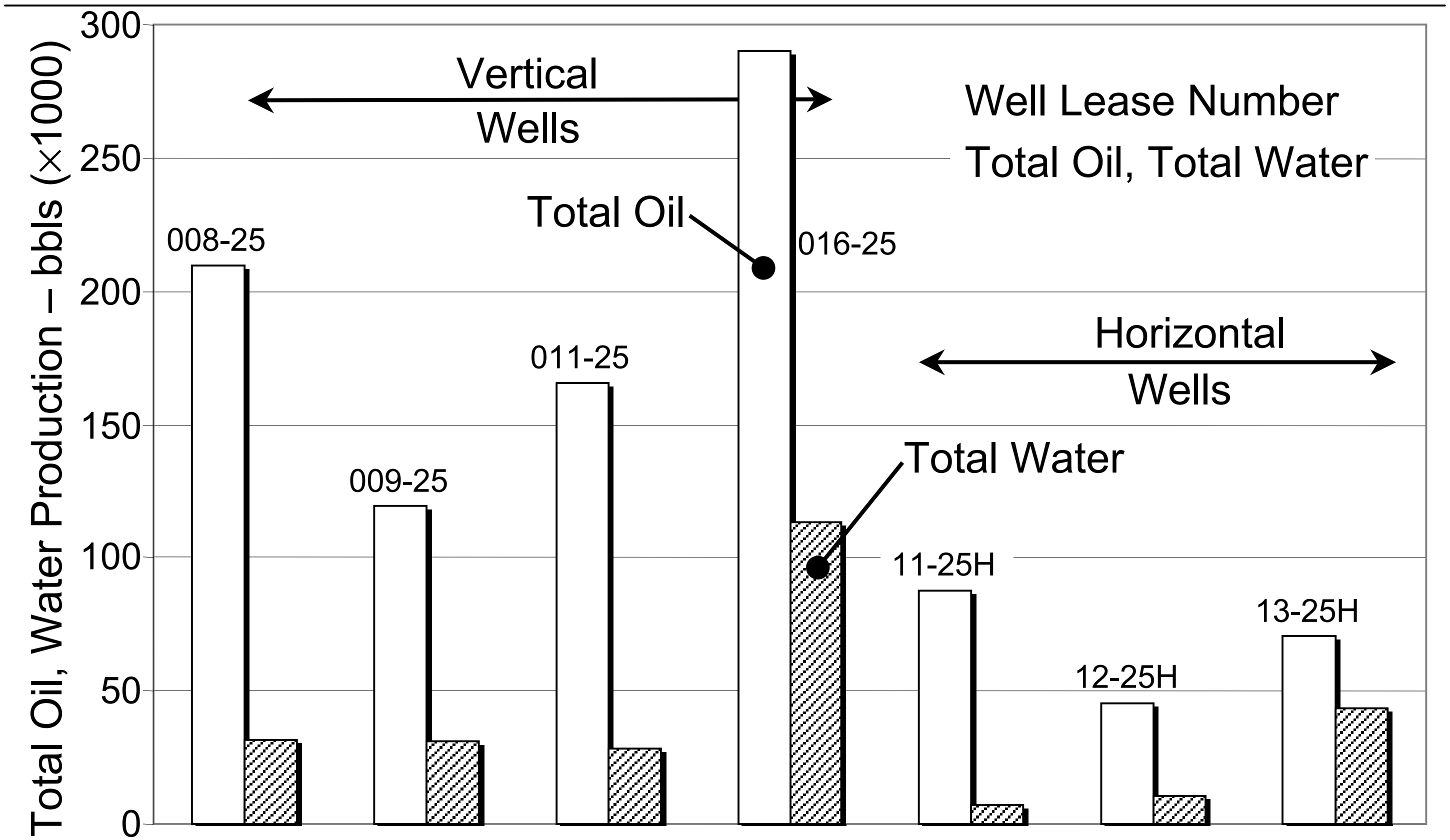


Figure 5.12: Water and Oil Cumulative Production Comparison, Plover Lake Field

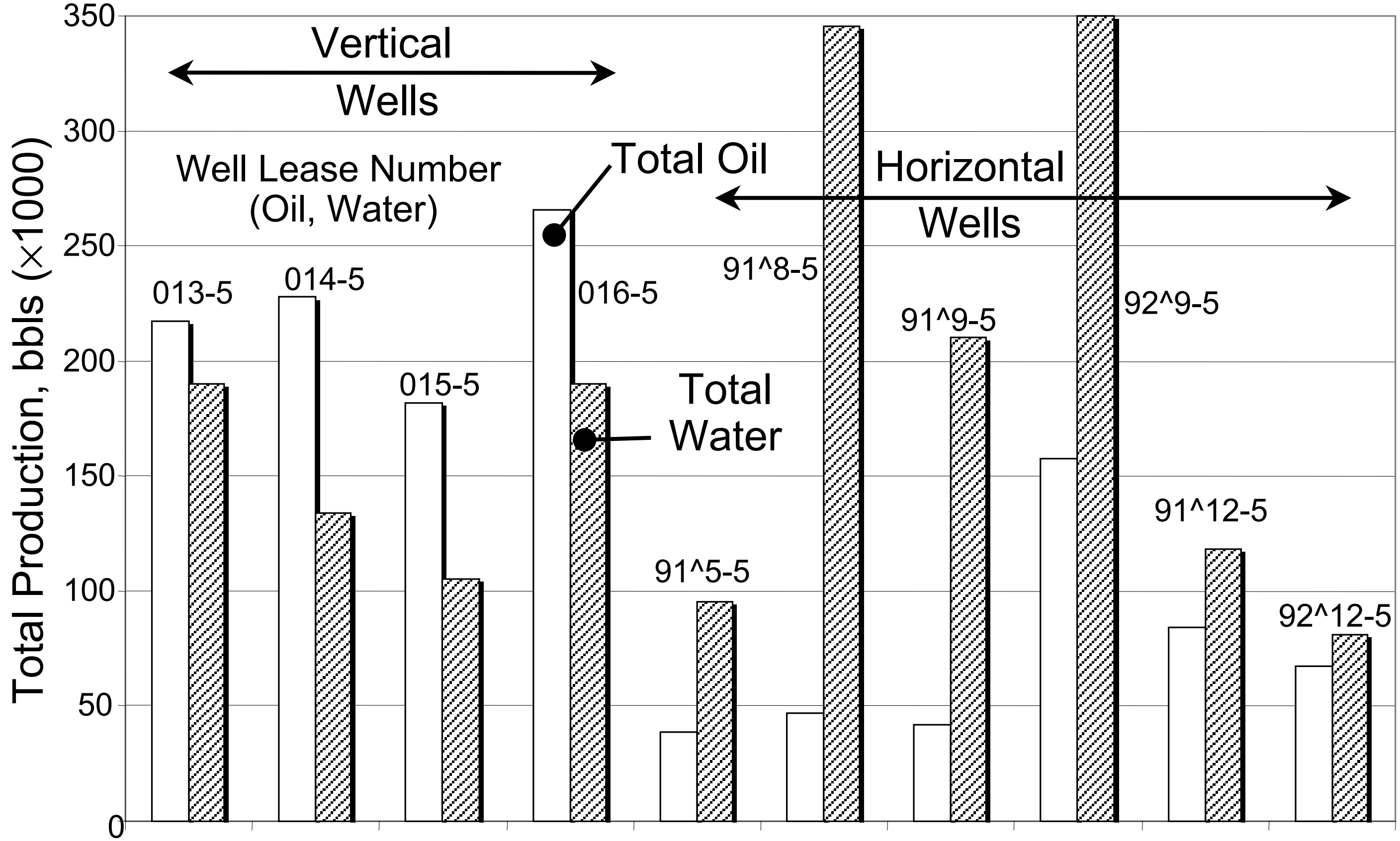


Figure 5.13: Water and Oil Cumulative Production Comparison, Cactus Lake Field

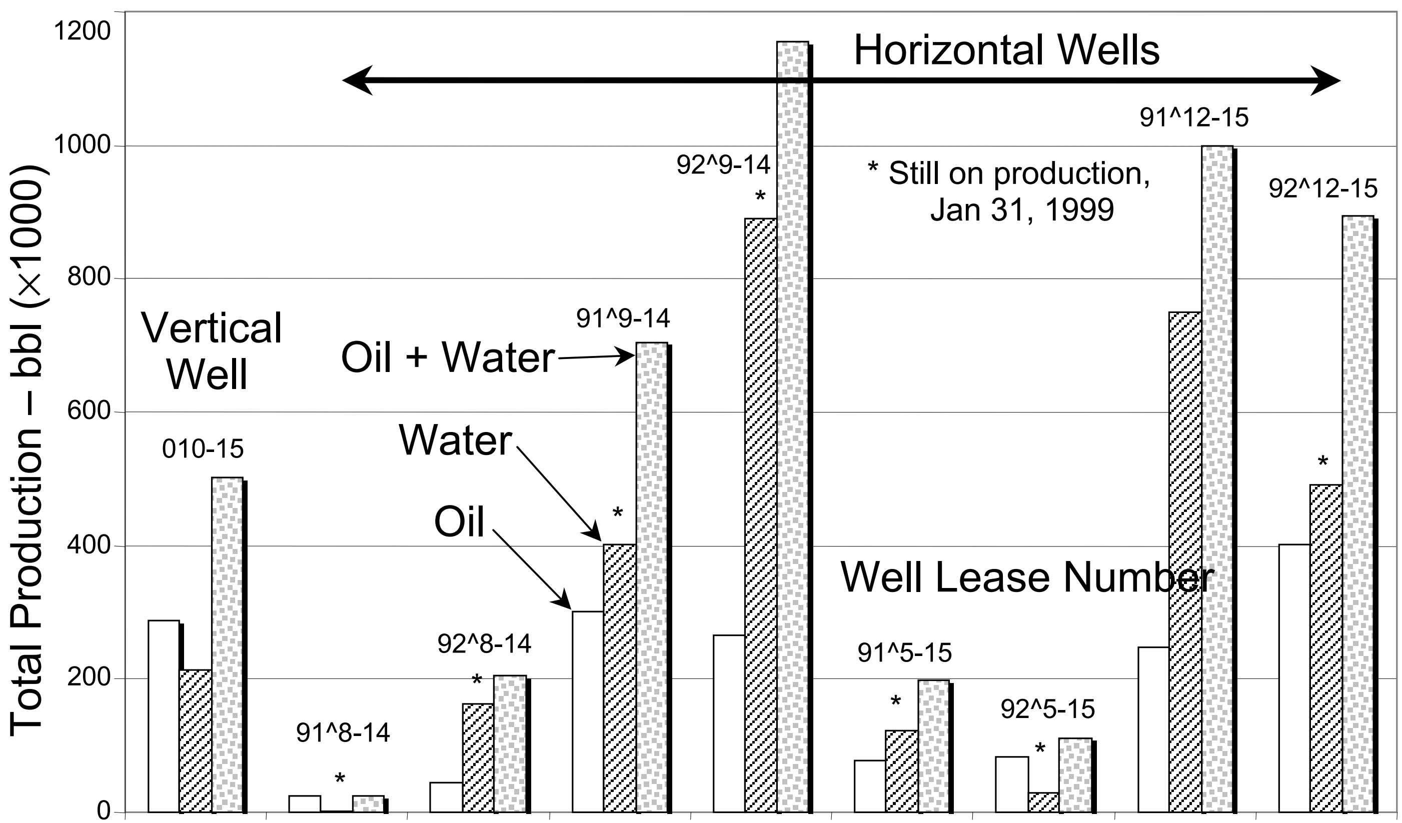


Figure 5.14: Changes of Processes as a Function of Porosity

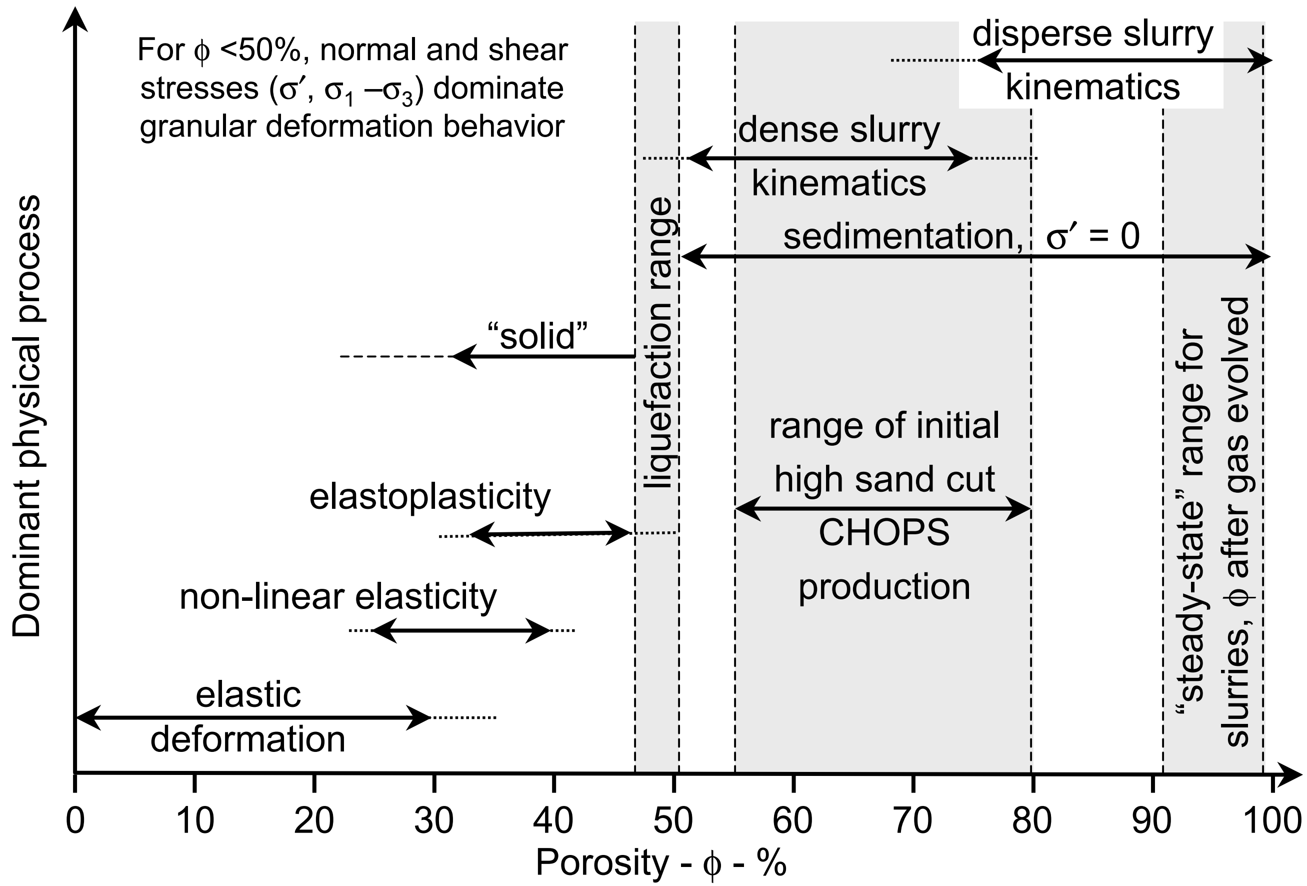
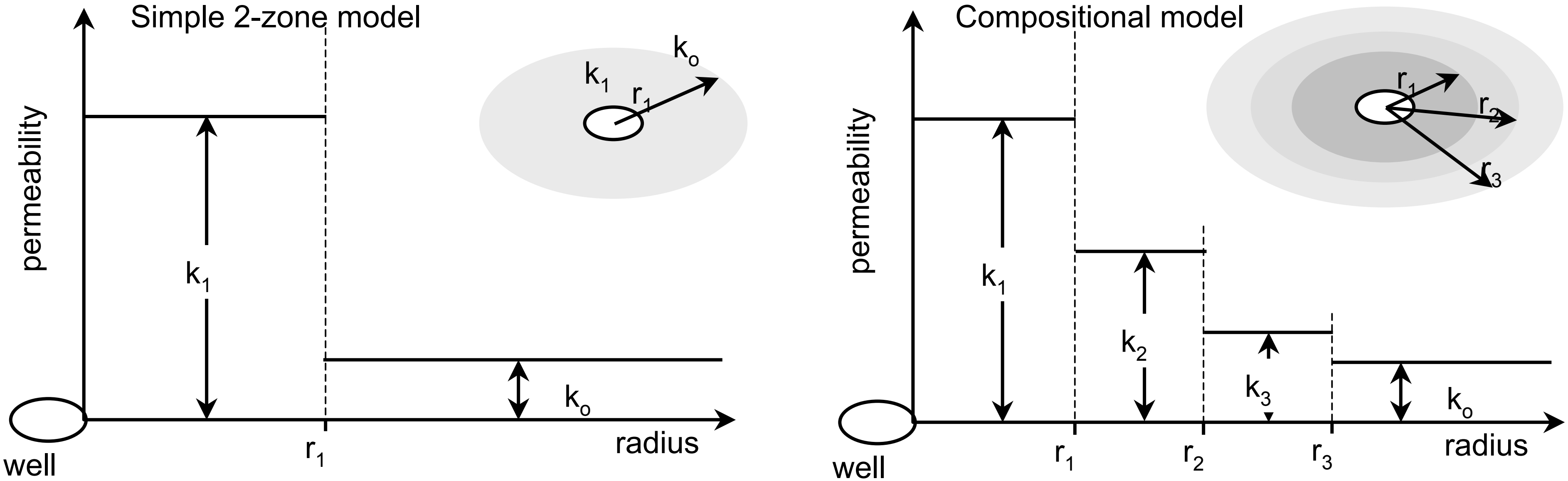


Figure 5.15: Simple Functions Selected to Emulate In Situ Permeability Distributions (Including a multi-zone compositional model)



Different permeability distribution models can be used, depending on one's view of the physical nature of the zones around the well, see Fig 4.6, 4.12, 4.13