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Implementing CHOPS in the Karazhanbas Heavy Oil Field, Kazakhstan

PATRICK M. COLLINS, M.Sc., P.Eng.
Petroleum Geomechanics Inc., Calgary, Alberta

MAURICE B. DUSSEAULT, Ph.D., P.Eng.
Professor of Earth Sciences, University of Waterloo, Ontario

DARCY DORSCHER, P.Eng.
Lancaster Petroleum, Kazakhstan
(formerly with Nations Energy Company Limited)

ED KUEBER, P.Eng.
Nations Energy Company Limited, Calgary, Alberta

Abstract

The Karazhanbas Field (KBM) is a giant shallow heavy oil field in western Kazakhstan, less than 460 m depth. It contains heavy oil (μ ~400 cP) in seven reservoir zones from several to 40 m thick in unconsolidated sands with porosities 28-32%, permeabilities of ~0.5 D, and an arkosic lithology with angular grains. There is no free gas cap, and the structure is divided into fault-controlled blocks, some with active water, others not.

Starting in 2000, Nations Energy Company Limited initiated cold heavy oil production with sand (CHOPS) in new areas on the flanks of the developed central part. PCPs are used to lift the oil, and sand is allowed to enter into perforated zones. Production of 6,000 m^3/day was reached by January 2004, an increase of over 4,000 m^3/d within 4 years. Sand flux is far lower than Canadian cases because of low oil viscosities; water flux is higher due to higher water mobility and active flank water.

We describe the geological setting of KBM, reservoir and petrophysical properties, and other geological information. Typical sand-oil-water production is documented, and well behaviour is contrasted with Canadian cases.

CHOPS is an economic success at KBM, allowing recovery factors of 8-15% from zones as thin as 3-10 meters, for which thermal technologies are not economically viable. It is planned that in the thickest zones CHOPS will be followed by steam stimulation to take advantage of the enhanced permeability and compressibility generated by the CHOPS process.

Introduction

CHOPS is a primary production technology recently developed in Canada involving intentional formation sand production to increase heavy oil rates from 0.5 – 2 m^3/d (with sand exclusion) to 5 – 50 m^3/d (allowing sand influx), at lower costs and without thermal stimulation. Currently, ~10,000 wells in Canada use CHOPS, yielding ~100,000 m^3/day. Issues relating to sand in the fluids, pumping, separation, transportation and disposal have been solved, and operating costs are ~50% of those for cyclic steam stimulation (CSS) or steam-assisted gravity drainage (SAGD).

The Karazhanbas Field (Karazhanbasmunai – or "KBM") possesses many characteristics conducive to successful CHOPS. The shallow targets are high-porosity unconsolidated sandstones containing heavy oil with CH_4 in solution. Active bottom water is absent, the production zones are homogeneous and flat-lying, oil saturations are high, and mobile water streaks appear to be absent.

There are also differences between KBM and Canadian experience: differences in viscosity, depth, mineralogy, and other factors mean that detailed assessment of CHOPS at KBM is worthwhile. This paper is based on actual field performance at KBM, with comparison to Canadian cases.

Background

KBM is a giant oil field located on the Buzachi Peninsula, in the northern Caspian Sea (**Figure 1**). The onshore part of the field is 30 km × 6 km, oriented east-west.

Fresh water sources are limited in this area, a major concern for oil field development; an arid climate and shallow saline groundwater mean fresh water for steam injection EOR must be pipelined from the Volga River in Russia.

History

KBM was discovered in 1974 and became the largest shallow viscous oil field being exploited within the USSR. Various steam stimulation and combustion techniques were used to reduce the viscosity from 350-450 cP to 1-10 cP for economic produceability.

In 1977, the Central Development Committee (CDC) of the Ministry of Petroleum Industry terminated all recovery schemes except for steam injection. The abandoned schemes correspond closely to similar methods abandoned by heavy oil field operators elsewhere in the world.

Project Renaissance

Nations Energy Company Limited (NECL) took over KBM operations in 1997 and initiated several aggressive development plans, based on previous KBM experience and Canadian heavy oil developments. In 2001, armed with new drilling and 3-D seismic data in several areas to supplement historical low-resolution 2-D seismic data, the New Development Plan was begun.

Up to Jan 1, 2003, more than 1700 wells had been drilled in the field: 1138 production wells, 441 injection wells, 89 control wells, 35 disposal wells, 40 abandoned wells and one suspended well. Most are located in the developed areas, the centre and western portion of the field.

By this time, KBM had produced a total of 18,300 thousand tonnes oil and 56,300 thousand tonnes fluids, ~7.7% of OOIP.

Geology

The KBM structure is situated in the structurally high portion of the Buzachi uplift, bordered by the Pre-Caspian (Pricaspiy) basins to the north, the southern Caspian Basin to the south, and the North Ustiuit basin to the east. The structure is a gentle, anticlinal fold complicated by western and eastern arches, which developed at different geological times.

Well data have delineated a geological profile that includes Lower Triassic, Middle Jurassic and Lower Cretaceous strata. Productive horizons are gently folded, flat-lying beds of sand in clastic cycles; carbonates are rare, evaporites absent. Sand-shale differentiation based on GR logs is a bit challenging as the arkosic sands have high radioactive K_{40} contents (clay, K-feldspars, lithic fragments), giving poor contrast with high SiO_2 silty shales.

Transgressive and regressive sea coast cycles led to periods of erosion and deposition with mild angular unconformities marking some erosional surfaces. General uplift and flexure were accompanied by normal faulting, and there is evidence of considerable strike-slip movement along some faults as well.

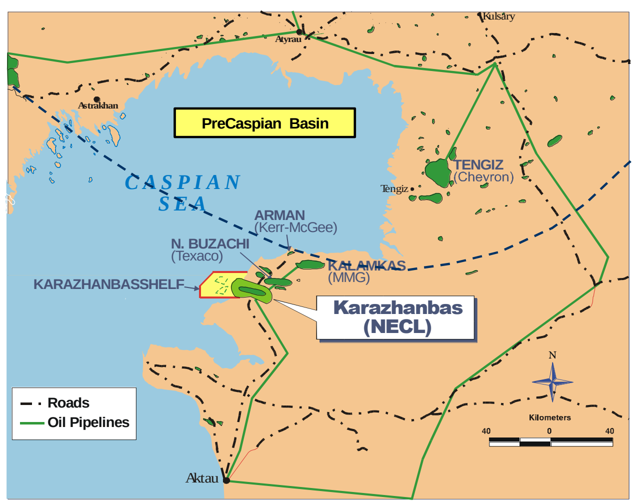
Fault Systems

A complex fault system exists, with a large major fault zone striking 105°-285° (**Figure 2)** separating the top of the structure into a southern elevated block and a northern down-thrown block: a subtle horst-graben system. This major fault zone is a series of imbricated faults striking ENE-WSW; it seems to have controlled regional fluid transportation and oil accumulation in structural highs. The fault system dips to the north, with the largest throw of 150 m in the west, gradually fading to 40 m in the east. Minor right-lateral strike-slip movement also exists.

In the western and eastern periclinal areas (structure flanks), secondary faults with vertical displacements of 5 to 130 m have been traced; these cut the strata into isolated reservoir blocks. Different oil-water contacts suggest that the faults are sealing or partially sealing. In the east, the small-scale faults can be grouped into two sets striking SW-NE and SE-NW, reflecting regional stress orientations.

Structural data are vital to planning for CHOPS and extending it into flank areas and into new sub-blocks because of the presence of active water zones on the flanks. Such structural details will also guide efficient IOR implementation.

Figure 1 Location of the Karazhanbas Field



(Courtesy NECL)

Producing Horizons

KBM has many sands; some are oil-bearing reservoirs of potential economic interest. These potential reservoirs are grouped into three "Objects"; in order of increasing depth and age (**Figures 3 and 4**):

- Object 1 consists of Horizons A, B and V
- Object 2 consists of Horizons G, D
- Object 3 consists of Horizons J1 and J2 (Jurassic Age)

The thick and permeable A, G and J1 horizons represent ~95% of OOIP, and are economic with current technology.

Before 2000, the development focused on the central portion of the field. Flank resource delineation in complicated regions started in June 2000, and large scale drilling and development began after 2001. The flanks are the monotonously dipping limbs of the anticlinal structure (**Figure 3)**; the New Development Areas are in these periclinal zones.

Figure 2 Top Structure Map of Object 1

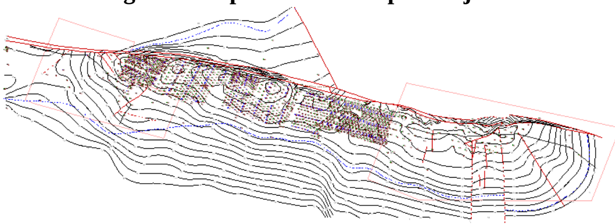


Figure 3 West-East cross-section through central KBM

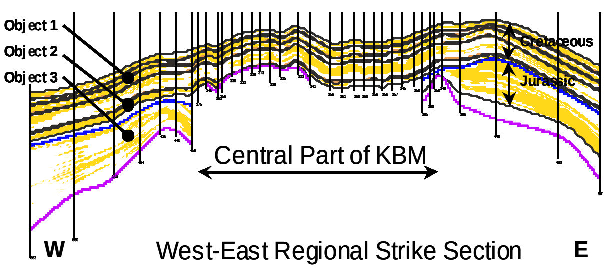
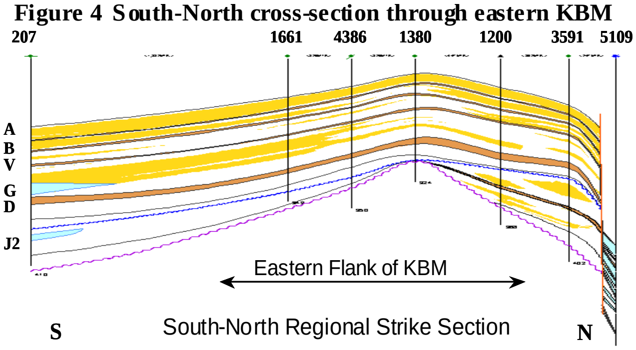


Figure 4 South-North cross-section through eastern KBM



CHOPS and the New Development Areas

The New Development Plan targeted rational full-field development through maximizing production from current areas and developing new areas on the flanks ("New Development Areas"), mainly the lightly-developed eastern flank. Initially, 29 new wells were drilled in the eastern flank and NECL decided to place these on cold production before implementing thermal stimulation. Goals were to provide more detailed and high quality information for guide development, to test new production equipment, and to determine if KBM zones would respond well to CHOPS. Well performance was extremely encouraging, so the process has been continued, and by June 2003, 23 new wells drilled in the eastern flank were producing under CHOPS conditions using PCPs.

The present average oil rate in the New Development Areas is 41.4 t/d for Object 1 wells, 20.3 t/d for Object 2 wells, and 22 t/d for Object 3 wells. Average initial oil rates in all Objects were in excess of 8 m^3/d/m of net pay. The average water cut of newly drilled wells is about 20% (from 10.7% to 32.6%). For comparison, current water cuts in steam stimulation usually exceed 80%.

By June 2003, 1160 thousand tonnes of oil have been produced in the New Development Areas. R_F values are 0.7% and 2.5% in Objects 1 and 2, 4.2% in Object 3 East, and 1.6% in Object 3 West.

Comparison with Canadian CHOPS

The best proof of CHOPS suitability for KBM is successful western Canadian analogues. Comparison criteria include reservoir, rock and fluid properties, listed in **Table 3**. At 18° to 20° API, KBM is at the lighter end of oil gravities for CHOPS. The eastern new development areas have neither free gas nor active bottom water zones. The reservoirs are fine-grained, uncemented sandstones of high porosity, but at <1 Darcy they are of much lower permeability compared to Canadian cases.

Solution Gas

Solution gas drive is the dominant drive mechanism in CHOPS. Producing below the bubble-point causes gas exsolution, and given the high oil viscosity, exsolved bubbles do not coalesce but are entrained in the oil, thereby creating "foamy oil". As the oil moves towards the well, Δp causes bubble expansion, which drives liquids towards the well. The benefit of solution gas drive is that it is ubiquitous and pervasive, providing a drive mechanism in all oil zones, leading to economic production even from very thin oil zones (<2.5 m).

Successful Canadian CHOPS reservoirs depend on foamy oil solution gas drive. Gas content depends on initial reservoir pressure because CH_4 solubility is pressure-dependent; thus, depleted reservoirs are not amenable to CHOPS methods.

Solution gas in Canadian cases ranges from 6 m^3/m^3 for shallow, underpressured cases (<400 m) to >16 m^3/m^3 for deeper reservoirs (700-800 m). In KBM, solution gas averages 8.9 m^3/t, though in the shallower New Development Area it can be as low as 5 m^3/t ($t \approx m^3$). It is difficult to obtain good bubble point data in heavy oils because of the extremely long times required for experimental equilibrium. Higher figures reported from Canada (>20-30 m^3) are certainly overestimates.

Viscosity

Canadian *in situ* viscosities range from 300 cP to 15,000 cP, with most fields >1000 cP (cP ≈ mPa•s). KBM oil is between 364 and 455 mPa•s (18°-20°API). The paraffin content is low and the asphaltene content is high, similar to Canadian fields. There is a trend observed in Canadian CHOPS fields that the well production rate and R_F increase as viscosity is lower. The highest API value in successful Canadian CHOPS fields appears to be the thin Provost Field, at 23.3° API, with a remarkable R_F of 50%. KBM, with a much lower viscosity than the average Canadian field, will have better well rates and perhaps a better R_F on average than Canadian fields.

Permeability

KBM permeability is relatively low: 0.175 to 0.500 D, compared to Canadian CHOPS fields: 0.5 to 5 D. This is a negative factor, especially with clay content as high as 10% in some cases. However, samples of the strata are difficult to obtain and test. Based on visual identification of many thick zones of relatively clean and uniform sand, we believe there is a much wider actual permeability range in KBM. Permeability is not an impediment to CHOPS success, but it is an issue that should be studied.

As in Canada, KBM sands are uncemented and therefore highly friable and easily damaged during coring and specimen preparation. Thus, there is large uncertainty in the data; even core expansion by one or two porosity units can affect petrophysical parameters substantially, particularly if interstitial clay is liberated. Reliability of analytical results depends on the specific technical methods of the analytical laboratories, as well as their experience in dealing with disturbed specimens. Hence, core porosities and permeabilities from specimens disturbed by coring and gas exsolution were adjusted to reservoir conditions using correction coefficients, so the KBM parameters are only approximate values. However, given that the KBM oil viscosity is lower, the clay content is higher, and the GOR is lower than most Canadian CHOPS fields, core disturbance at KBM is likely to be less than in Canadian experience, as later confirmed by special core analyses.

Stratigraphy

KBM and successful Canadian CHOPS fields are geologically similar, though KBM is far more faulted and compartmentalized. Oil migration from pre-Cretaceous shales moved up-dip through faults or unconformities to structurally and stratigraphically controlled traps. There are many sand zones separated by silty sands and silty shale beds, with overlying thick shale sequences. KBM has more thick individual pay zones, at least two potential zones per well, and the net pay per well is usually higher in KBM than in Canada.

Water Zones

There are no active water legs (i.e., bottom water or a zone of high water mobility) in successful Canadian CHOPS fields. Active bottom water is rare in the KBM zones, but there is active flank water, particularly in Object 3 targets. KBM must look more closely at this issue, and undertake development preferentially in reservoir blocks and zones that do not have active bottom water or close-by flank water. Water incursion may become problematic in the future.

KBM Geomechanics

Karazhanbasmunai is an elongated reservoir of shallow unconsolidated sands and mudstones. Despite a complex tectonic history, the formations are weak; some wells have wellbore convergence of 20-25 mm between tripping out after reaching the total depth and logging. Poisson's ratios of 0.45 are common, and these are high.

The formations are overpressured due to virgin conditions, various steam and water injection schemes, and disposal of produced water into edge zones. In the new areas, pressures in the southern flank are higher due to disposal wells. These have raised the stress levels considerably: an Eaton prediction using Poisson's ratio of 0.45 and the overpressure gradient of 1.38 SG gives a horizontal stress gradient of 19.9 kPa/m. A step-rate test in Horizon G gave 20.6 kPa/m, lower than the log-derived overburden gradient of 21.78 kPa/m. Also, there is evidence of interwell communication between a water disposal injector co-aligned with two wells along the maximum horizontal stress orientation, without communication with two nearer non-aligned wells. This implies vertical fracturing; hence the minimum *in situ* stress is horizontal. At KBM, the relative magnitudes of the principal stresses is likely $\sigma_H > \sigma_v > \sigma_h$, with $\sigma_v \approx \sigma_h$.

Borehole breakout occurrences imply a strong horizontal stress anisotropy; the maximum horizontal stress is NW-SE in the Cretaceous, with an indication of a possible rotation to NE-SW in the deeper Jurassic, but more data are required for confirmation. Any communication between wells in this stress regime would be parallel to the maximum horizontal stress as it is the most stable orientation of wormholes (slurry channels). More borehole breakout analyses would provide a better understanding of the stress orientations across the field.

We expected no issues relating to subsidence or to casing shear in the CHOPS development, and there has been no evidence of this occurring.

KARAZHANBAS RESERVOIR FLUIDS

Gas Composition

The solution gas is 93-97% methane, 0-3% N_2, and the remainder C_2^+. Traces of carbon dioxide are present, <0.3%.

Bubble Point and Gas:Oil Ratio, GOR

The bubble point pressure in these wells is below the reservoir pressure at the time of drilling. Originally, KBM was overpressured, with CH_4 solubility below saturated conditions, and no free gas. This is good news for CHOPS implementation, as the foamy oil drive mechanism will be at its maximum potential.

GOR values from 63 wells show lower values as development progressed because of degassing and driving gas from solution with high temperature steam effects. The reservoirs appear to have bubble-point pressures below the virgin reservoir pore pressure (**Table 1**).

Table 1: KBM Gas:Oil Ratios and Solution Gas

Object	Initial GOR m^3/t	Current GOR m^3/t	Gas Solubility v/v/atm
Object 1	8.9	5.58	0.185
Object 2	8.9	6.86	0.217
Object 3	9.2	9.2	0.20

Considering that intensive drilling has been done in new areas, the same situation might be expected. However, in CHOPS wells in Canada, GOR tends to climb only very slowly, often remaining constant with time. This means that a continuous gas phase is not being developed, or is developing slowly with respect to the increase in drainage radius. It is believed that this arises because of the high viscosity of the oil and the consequent low gas diffusivity. It is likely that KBM will see GOR values rising with time in CHOPS wells, but more slowly than in conventional methods that are non-thermal. In the past 1.5 years, large increases in GOR have been observed in some wells that have since been shut-in.

Oil Viscosity

Similar to the GOR values, oil viscosity is higher in the currently developed areas, probably because of degassing. Viscosities below are averages of a large number of samples taken from various wells. Interestingly, a higher viscosity with depth is recorded, but the differences are not great (**Table 2**).

The temperature (increasing with depth) has a great impact on the *in situ* viscosity of heavy oils, which are extremely temperature-sensitive. This factor, plus the gas in solution, leads to differences in viscosities between formations.

Table 2: KBM Dead Oil Viscosities

Object	Initial Viscosity (mPa•s)	Current Viscosity (mPa•s)
Object 1	240	410
Object 2	340	364
Object 3	402	402

Application of CHOPS to KBM

CHOPS technology is currently responsible for 100,000 m^3/d of Canadian oil production, approximately 20% of current total oil production in Canada, including conventional, *in situ*, and surface mining operations.

CHOPS Characteristics

CHOPS evolved in Canada because it slowly became obvious that oil production rates with sand were far superior to rates without sand. Production rates in Canadian heavy oil fields are several to 20 times larger if the sand is allowed to enter the well. CHOPS is based on the following principles, developed over a few decades of trial and error:

- formation sand is deliberately produced with the fluids
- well completions encourage sand influx
- no hydraulic fracturing, slotted liners, screens, or gravel packs are ever used to stop sand influx
- artificial lift must cope with continuous sand influx; PCPs are preferred in most, but not all, cases
- production rates drop dramatically if sand production stops
- aggressive well workover methodologies are designed to encourage the re-initiation of sand influx

Typical CHOPS Well Behaviour

The behaviour of CHOPS wells is well known (Dusseault, 2007); the distinctive feature of this process being foamy oil drive with the intentional production of sand.

Sand production continually increases well productivity for the first few years, in contrast to conventional wells in which productivity is highest at the onset. Initial sand flux is very high, perhaps exceeding 25%/vol, declining to a steady-state value, about 1.5%/vol within weeks or months. Oil rates start modestly and increase, reaching a peak in 0.5-2 years, then gradually decline. After several years' decline to a low oil rate, it may be possible to rehabilitate the well and re-establish better production, so a well can go through several cycles. Subsequent peak oil and sand rates are not as high as the primary cycle.

Water production in a new well is usually low, from <5% to 15% water. Some fields show a constant rate for many years, or the rate may increase slowly, usually going up as oil rate declines. However, some fields show sudden and massive water influx, indicating that water has broken through from an active water zone, or that flank water has migrated into the well through the formation of high water saturation channels.

Production Enhancement Mechanisms

There are several mechanisms responsible for the production rate enhancement observed in CHOPS wells[4,20]. Sand withdrawal through liquefaction and transport to the well creates voidage within the horizon, most likely a channelled and remoulded zone filled with a slurry of sand, water, oil, and gas. The zone increases permeability and the well behaves as if it has an increasing radius with time. Production enhancement from this effect alone should approach a factor of 4 to 5, but later in the life of the well after large cumulative quantities of sand have been produced (200 – 2500 m^3/well).

Observed zones of reduced seismic velocities and enhanced seismic attenuations are aligned along a linear trend that is stress-dependent, which seems to be the orientation of the largest horizontal stress (σ_{Hmax}) in both KBM and Alberta/Saskatchewan. A strongly anisotropic stress field would be expected to generate an oriented macroscopic disturbed zone shape. Stress redistribution during production can accelerate the propagation of the yielded dilated zone away from the well.

Foamy Oil Drive

CHOPS depends on solution gas. CHOPS heavy oils reservoirs have gas in solution; the bubble point usually is at or near the initial reservoir pressure. Wells are subjected to aggressive drawdown and gas exsolves as bubbles in the porous matrix. However, a continuous gas phase is not formed; the gas remains as bubbles that expand in response to pressure decline during flow to the well. Hence, the bubbles act as an "internal drive", driving the slurry to the well at a velocity greater than predicted by conventional liquid flow theories.

In the more viscous oils, gas:oil ratios (GOR) remain constant, and virgin pressures may be encountered during infill drilling only a few hundred metres from existing producing wells. With production, gas bubbles continue to expand and exsolve, which then provides a pressure support buffer that conserves gas pressures further within the reservoir. This is important for CHOPS because delayed gas depletion means that as long as the process continues to propagate away from the well, drive energy from the solution gas can be accessed.

Foamy oil develops in a zone that propagates outward from the well, following the growth of the disturbed and remoulded zone. This pushes the zone of highest pressure gradient far from the well, where it helps to destabilize the sand by pore throat blockage by bubbles. Therefore, rather than impeding oil production and recovery, operating below the bubble point means a dramatic increase in production rate and recovery.

Elimination of Skin Effects

Heavy oil reservoirs can have high skin effects due to plugging of pore throats with precipitated asphaltenes and with mobilized fine-grained particles and clays. The sand production from CHOPS continually shears and disturbs the sand grains, which prevents pore throat plugging. Furthermore, as this disturbed zone of hyper-porosity and permeability extends away from the wellbore, the wellbore skin becomes increasingly negative.

Modelling CHOPS

Conventional reservoir and well simulators cannot fully model all the CHOPS physical processes:

- liquefaction of the matrix with large porosity changes
- stress-strain-yield coupled with fluid flow
- transient compositional conditions for foamy oil drive
- slurry flow *in situ*
- continuously changing boundary conditions
- massive changes in physical parameters because of dilation and liquefaction, over both time and space.
- stress redistribution[1,14]
- results from sampling and testing of uncertain reliability

Many history matches of the behaviour of laboratory sand packs and field data have been carried out using conventional simulators,[2,8,9,10] but with a number of uncontrolled or ill-constrained parameter modifications (solubilities, gas contents, bubble points, relative permeabilities, compressibilities, etc.). It is uncertain whether these parameters and laboratory processes have a direct and useful relationship with in situ mechanisms and the large-scale system alterations that take place.

Geomechanics-Based Modeling

More correct physical simulation of CHOPS are available[16]. Progress continues to develop analytical and semi-analytical solutions to CHOPS, despite being hampered by the massive non-linearities and the complexity of the processes. Simplified models of compact growth and channel growth had their origins in early attempts to understand stress, dilation and yield around circular openings[13,17,18]. The sand flux models are all based on introducing some aspects of stress, shear-induced dilation, and concomitant permeability increases, with necessary simplifications.

The Geilikman family of semi-analytical models[4,5,6,7] links the drawdown rate of wells to the magnitude of sand flux. 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. Currently, all models must be repeatedly calibrated to sand production history to develop realistic predictions.

New mathematical simulators have been based on coupled stress-flow formulations solved with the finite element method.[12,15,19,21] Most aspects of CHOPS, with the exception of slurry flow, are gradually being incorporated into modeling.

Most geomechanics-based models being developed are coupled models, but stop short of addressing all relevant physical processes. "Volume-averaged" properties are used; small-scale processes such as wormhole growth or dislodging of a group of grains under a high pressure gradient are incorporated empirically into the models, linked only to the volume of sand produced historically. There is no known model that actually simulates channel development or zone growth in a physically rigorous manner, and there may never be, given the complexities involved.

Modelling by Analogy

Because of the uncertainties in predictions of CHOPS performance with numerical modelling, the approach used to predict the behaviour of CHOPS wells in KBM was based upon analogues. Although not based on the process physics, this approach uses actual well and field behaviour for an empirical prediction of the performance of the subject reservoir.

This analogical approach requires a quantification of the ranges of the subject reservoir's pertinent characteristics: geology, fluids, and fluid flow parameters. Next, search databases for existing CHOPS fields with comparable characteristics. If many analogues exist, select a subset of those with documented well histories. These include individual well production rates (oil, water, and preferably sand and gas) and workovers. For analogues with too many wells to reasonably analyze in an appropriate time frame, select a subset cluster of wells over a specific area (e.g.: 2-4 km^2). Ideally, the resultant short list of analogues would have reservoir characteristics that bracket those of the subject reservoir.

Based on comparisons with the analogues, estimate the "typical" production of oil, water, gas and sand for the new case. Estimates for both pessimistic and optimistic scenarios aid in risk assessment.

This approach to modeling and prediction is extremely robust because it is based on factual, historical data, and makes few assumptions. However, it must be used with caution and recalibrated as data are collected from a new project.

Once quality data are available from the active project, analytical modelling can be used on both the new project, and on analogues with sufficient data. Those models providing a good history match could then be used for predictions of performance.

CHOPS at KBM

CHOPS began in the Karazhanbas Field mid-2000. As of mid-2003, the wells in the Eastern Pericline, New Development Area, are on cold production. CHOPS wells are completed in single zones within the Cretaceous and Jurassic horizons. These wells are located in an area that has not been previously exploited by other techniques, such as the steamfloods and firefloods used in the Central Area. As such, this area is not thermally altered, with the possible exception that (i) formation fluid pressures are elevated to the west and may influence nearby formation pressures, and (ii) the thermal strains induced by the thermal processes may have increased the horizontal stresses. Neither effect should significantly affect the CHOPS process.

Oil production rates ramp up to 30-60 tonne/day, which is good compared to CHOPS wells in Canada, where a typical rate would be 15-20 tonnes. This is likely due to the KBM Field being on the lower end of the viscosity range for CHOPS, therefore the oil flows more easily to the wells.

Water incursion has not adversely affected oil production. This is encouraging, since there are large sources of edge water, both from the steamflood in the central area, and from the disposal of produced steamflood water into the lower zones of the reservoir, necessarily within 500 m of surface. This continued disposal of water into the perimeter will result in continued water breakthrough to the CHOPS wells. It would be preferable to delay this eventuality as long as possible, as the lower mobility of water results in preferential water production.

Maturing CHOPS wells have already produced in excess of 40,000 m^3 of oil, all without any steam injection, and at commercially viable rates. It seems reasonable to assume that the ultimate CHOPS production from these wells will be at least 50% to 100% higher, once the CHOPS drive process is exhausted, and before any IOR or EOR process is attempted.

The production trends observed in KBM CHOPS wells were examined with respect to reservoir parameters, for the purpose of identifying those parameters that had a controlling effect on oil production. Variables were cross-plotted against cumulative oil production and oil production rates.

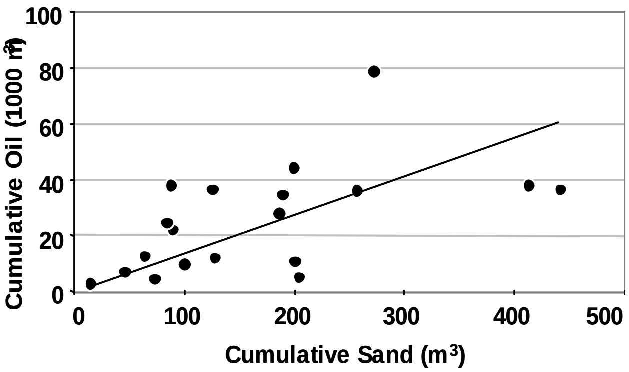
Net Pay

Net pay was expected to correlate with the oil rate since the well would be in vertical communication with more of the reserve. However, there was a weak relationship between oil rate and net pay, showing that although thicker pay zones will produce at higher rates, there is still considerable unaccounted variability. Parameters such as permeability and the progressive enhancement of the well productivity due to the CHOPS process will result in considerable deviation from the anticipated straight-line trend.

Cumulative Sand Production

Cumulative sand production had a fairly good correlation with cumulative oil production (**Figure 5**). This is particularly true at low levels of cumulative oil production, which may reflect the fact that there is lower variability of cumulative sand production for the early life of the wells. Later, when CHOPS is established and mature, the continued oil production will take place with lower sand rates, and these may vary considerably among wells. Continued oil production in a well with little or no sand production will skew this relationship. However, these wells are likely not being operated in an optimal manner for CHOPS, and should be re-examined in terms of completion and well strategies.

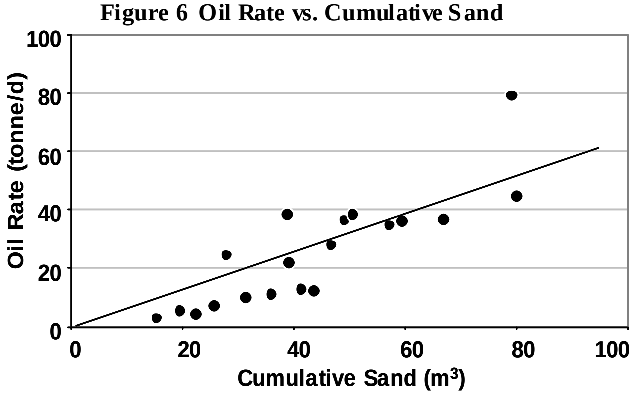
Figure 5 Cumulative Oil vs. Cumulative Sand



However, **Figure 6** shows that there is a stronger relationship between the oil rate and the cumulative sand production, as others[11] have found. This relationship was the strongest one found in this analysis, and is the strongest proof that CHOPS is being successfully applied at KBM. This relationship does not account for variations in geology or pay thickness; therefore, the relationship between oil rate and cumulative sand production is likely stronger than indicated by this plot.

The implication of this figure is significant: for optimal well performance, sand production must be encouraged. Sand production must be continuous, throughout the life of the well, in order to allow higher rates of recovery. As such, completion and stimulation designs must allow and initiate the production of sand, and the operation and workovers in each well should ensure that continuous, stable sand production occurs.

Figure 6 Oil Rate vs. Cumulative Sand



Sand Cut

If the cumulative sand production is a measure of the health of a CHOPS well, then the sand cut is its pulse. Without continual sand production, the CHOPS process will falter and possibly stagnate. Sand production must be measured on a well by well basis so that remedial workovers can be done to reinitiate sand production when and where required.

Sand cuts were initially highly variable and at 5% to 7%. KBM sand cuts would have been higher had the wells been produced aggressively on initial completion, and in fact sand cuts did exceed 12% on some wells. However, the conservative operating procedure adopted was to limit drawdown to keep the sand influx below a certain level to avoid sanding PCPs and reduce early wear. Sand cuts stabilized to a background level of 0.5% relatively quickly. Since high early sand cuts are from a time when CHOPS has had little time to enhance well performance, this would result in a poor or negative correlation with oil rates. Well productivity data showed a high scatter of data points, with almost no correlation with the sand cut.

When a small volume of production is captured through a sampling tubular, a bitumen, solids, & water (BS&W) analysis provides an instantaneous sand cut. This is precise, but it fails to capture the variability of sand production, particularly when there are slugs of sand production. In contrast, periodically measuring the total volume of sand accumulated in the production storage tank provides an imprecise but accurate measure of sand volume, later correlated to a dry sand mass. The cumulative method is less precise but more accurate, and the total sand production is measured continually over time.

Water Rate

There was an expectation that the water cut would have two opposite effects: Firstly, water influx would interfere with the oil production, resulting in a negative correlation. However, water influx would generally occur later in the life of the well when cumulative sand production and oil rates are higher, resulting in a positive correlation with water cut.

The data showed no strong correlation between the oil rate and the water rate. There was a slight positive trend with high scatter. It was reassuring that high oil rates were maintained at high water cuts. This is important, since it means that the onset of significant water production does not mean that the well will have to be shut-in due to excessive water cuts. Given that the viscosity of the KBM oil is towards the lower end of the range for CHOPS experience, it means that the mobility ratio between oil and water is lower, and this is advantageous when water production also occurs. It suggests that waterflooding would be advantageous; as was later planned for sands thinner than 7m.

Water cuts are higher towards the south-east of the Eastern Pericline, which may represent the incursion of edge water into the CHOPS area.

Cumulative Oil Production

The more mature wells have produced approximately 40,000 m^3 of oil from the J1 zone with the CHOPS process. The best producer, Well 4834, has produced twice that amount. It is adjacent to the central area of the KBM Field, where extensive steamflooding has occurred. Downdip, Wells 4529 & 4670 have typical oil production, but their water production is even higher.

Canadian Analogues

To assess the suitability of CHOPS to KBM, the available Canadian data were examined to select a set of CHOPS analogues that covered the range of KBM reservoir conditions. Compiling analogues provides:

- compelling proof of the merits of CHOPS
- generation of a set of criteria for the successful establishment and management of CHOPS wells
- production predictions for wells in new areas using the methods of extrapolation and interpolation, with adjustments based on experience
- reasonable estimates to be made for recovery factors (R_F), sand rates, peak well production rates, etc.

Table 3 Comparison of KBM with Canadian CHOPS Fields

Field		Zone	Depth (m)	Thickn's (m)	Initial Press. (MPa)	Porosity %	Perm. (mD)	Temp. (°C)	OIL Density (kg/m^3)	API Gravity (°API)	Sw (%)	Sol'n Gas (m^3/m^3)	Absolute Viscosity @ 30°C (mPa·s)	R_F (%)	k·h/μ (mD·m/cP)
KBM	Object 1	A, B, V	258	10	4	28	445	26	939		28	5.58	410	-	10.85
KBM	Object 2	D, G	290	16.2	4.5	30	472	27	940		26	6.86	364	-	21.01
KBM	Object 3	J1, J2	375	22.2	4.3	29	J1 500 J2 175	30	940		31	8	455	-	8.54
Luseland		MbkknM_ss	739	11.8	6.3	31.5	3000	30	983	12.4	25	10	1400	11.4	25.29
Provost		Kdina	835	3.22	5.68	26	802	27	914	23.3	22	7	42	50	61.49
Lashburn W. Sparky		Ksprky_ss	537	4.55	~5	25	1497		991	11.3	30		10835	15	0.63
Edam Waseca		Kwaseca	431	6.25	~4	27	3610		988	11.7	30		15880	15.3	1.42
Marwayne		Ksparky	514	3.55	3	33		22	981	12.7	19	8	8301	7	0.00
Lwr. Grand Rapids		Kgrad_rp_L	550	12.5	3.8	34	3544	21		11	13		7103		6.24
Edam North Waseca		Kwaseca	444	5.3	~4	25			988	11.7	30		6140	11.7	
Low Lake Waseca		Kwaseca	509	3.65	~4.5	36	5748		971	14.2	30		7840	24.5	2.68
Baldwinton Sparky		Ksparky	599	4.3	~5.5	25	294		978	13.2	30		3789	24.3	0.33
Freemont W. Sparky		Ksparky	641	2.9	~6	35	1933		955	16.7	30		1562	16.5	3.59

*data from 2003

- a data bank for comparison with KBM CHOPS performance, serving as an aid to rational decision-making
- a means to prove or disprove hypotheses, or to identify exceptions that are important to understand

The analogues all came from the Canadian experience of course, as there are few CHOPS data extant outside of Canada. **Table 3** provides a compilation of reservoir characteristics for KBM and the analogue Canadian CHOPS fields. These analogues can be revisited in the future in Canada as the history of CHOPS in KBM progresses.

Lessons from Analogues

Ten Canadian CHOPS analogue fields were chosen to bracket the range of KBM viscosities. A number of lessons have been learned from these CHOPS analogues.

- where horizontal wells coexisted in the same formation, CHOPS was more economical and had higher R_Fs
- not all wells are successful: 10% to 30% of the CHOPS wells may be uneconomical over their life span
- there is high uncertainty in our ability to predict well rates, well cumulative production, and field behaviour with CHOPS despite the most careful analysis and data collection. Although we believe this situation will be ameliorated in the future, a large uncertainty will remain
- wells show production increase periods lasting from 1 to 4 years after CHOPS initiation
- sand cuts start at 30% - 40%, declining to 0.5% - 1.5% after 4-5 months
- wells general start with a high sand cut, and drop off after a few months to stabilize at 0.5% to 8% sand in the most viscous oils
- water presence and proximity are critical to CHOPS well behaviour
- underlying aquifers may not be a problem if there is sufficient hydraulic impedance from intervening shales and cemented layers; however, edge water can incur
- after water breakthrough, WOR>3, aggressive production can result in higher R_Fs due to viscous drag if sand influx can also be sustained
- the end phase in CHOPS wells is usually characterized by rapidly increasing water cuts and drops in oil rates
- an average CHOPS well can be expected to produce from 10,000 m^3 to 30,000 m^3 of oil in a life span of 5-10 years on CHOPS, and exceptionally to 100,000 m^3.
- CHOPS in Canada has been used in small fields with low viscosity (100-300 cP), but most commonly in large fields with viscosities greater than 1000 cP, up to 15,000 cP.
- recovery rates are higher with lighter, low-viscosity oils
- reported GOR data are of very poor quality
- the GOR should remain stable, since the gas is co-produced with the associated oil
- higher GORs for a mature CHOPS field indicate a continuous gas phase and the end of foamy oil drive

- sufficient solution gas must exist for successful CHOPS implementation. This should be remembered in converting old production areas to CHOPS, when shutting in high GOR wells, and in preserving reservoir pressures
- ultimate R_Fs range from 14% to >20%, and in the low viscosity Provost Field analogue, almost 50%. This was in a thin zone, and it appears that better recovery factors can be achieved in thin zones.
- zones as thin as 2.5 m have been economically produced with CHOPS
- aggressive completions stimulate a stronger development of the foamy oil drive mechanism and a greater sand flux
- analyses of the well rates and the lifting capacity of the well must be continually reassessed to ensure the optimal production of water, sand, and oil

Given the similarities of the unconsolidated nature of the KBM strata, the generally fine- to medium-grained nature of the sand, and the solution gas content, CHOPS will be economically successful in KBM. KBM properties are generally better than Canadian oil field properties, with the exception of a somewhat lower permeability. Once a well has been drilled and paid for in a zone, it may be feasible at KBM to move uphole and exploit zones as thin as 2.5-3.5 m.

It was expected that recovery factors in KBM would be 25-35%, before EOR implementation. Field performance to date has been lower, with recoveries varying from 8% to 15%. The onset of significantly higher GORs in some wells reduced some well pressures to 1 MPa, at which point the wells were shut-in pending EOR implementation. In contrast, the R_F in the central/old area of the field where CHOPS was not applied was 7.7%. The recovery factor in the CHOPS area has exceeded this in 1/5 of the time frame compared to the old central area where EOR process have been implemented early in the well life.

Predictive Model

The complex physics associated with the CHOPS process renders conventional reservoir simulators useless as analytical tools. In 2003, closed-form solutions and numerical approximations for CHOPS were only then being developed, and these are in their infancy. At present, the best method of predicting CHOPS performance is to examine the performance of existing wells, and to interpolate and extrapolate that performance to new wells. This process can be aided by comparison to existing production data on CHOPS wells from other fields.

Vogel Equation

Optimal CHOPS production requires an appropriate bottom-hole pressure to maximize oil flow rates. Vogel found that a single dimensionless Inflow Performance Relationship (IPR) was valid for several hypothetical solution-gas drive reservoirs and for a wide range of data. Vogel's equation is a nonlinear extension to the linear Productivity Index (PI) equation where the reservoir pressure is below the bubble-point pressure, P_{bp}. Vogel's IPR equation is:

$$\frac{q_x}{q_{x(\max)}} = 1 - 0.20\left(\frac{p_{wf}}{p_{R(avg)}}\right) - 0.80\left(\frac{p_{wf}}{p_{R(avg)}}\right)^2 \qquad [1]$$

where

x = o (oil, in this case)

q_x = measured stabilized productivity surface flow rate

$q_{x(\max)}$ = maximum producing rate q_x of liquid "x" at the maximum drawdown, $p_{wf} = 0$

p_{wf} = measured stabilized flowing pressure in the wellbore

$p_{R(avg)}$ = average reservoir pressure

The Vogel equation was found to apply to any reservoir in which gas saturation increases as pressure is decreased, even though the original application was for saturated reservoirs with a dissolved-gas drive. It was also shown to apply to wells with a water cut, since the increasing gas saturation will concomitantly reduce the permeability to water. This approach has been used successfully for wells with water cuts up to 97%. Therefore, for the corresponding equations for water and liquid (oil + water) at flowing pressures below the bubble point, the subscript "x" in **Equation 1** should be replaced by "w" and "l" (i.e., o+w), respectively.

Note that the water phase IPR below the bubble-point pressure is also non-linear because of the presence of exsolved gas in the pore space. However, for undersaturated reservoirs where the reservoir pressure is above the bubble-point, the linear PI equations would apply.

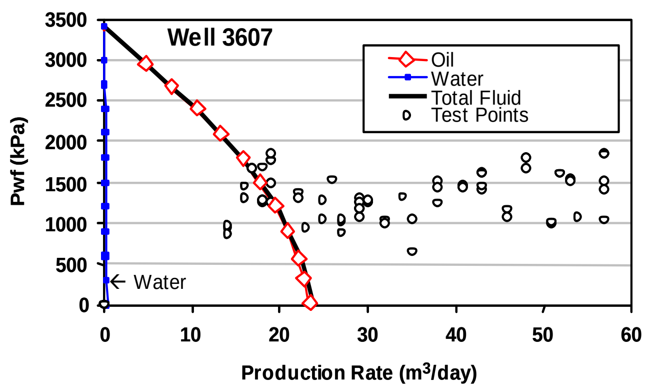
The beauty of the Vogel equation is in its simplicity. Knowing the reservoir pressure and the bubble point, a single pair of test data, consisting of the oil flow rate and bottomhole flowing pressure, can be used to extrapolate to oil production rates at different flowing pressures. The equation has been found to apply to any reservoir in which gas saturation increases as pressure is decreased, even though the original application was for saturated reservoirs with a dissolved-gas drive.

Application of Vogel's Equation to KBM

The major assumption made in Vogel's equation is that variations in the productivity index are attributable to hydraulic impedance caused by the creation of free gas in the pore space, all other factors being equal. As such, the equation is useful for determining the change in production with a change in downhole flowing pressure, which is also of course related to the rotational speed of the PCP.

However, for the KBM Field, this methodology is only valid for a limited time period after the determination of each individual Vogel curve, each of which is uniquely dependent upon the $(p_{wf},q_o)_t$ recorded at the time of the test (the one-point fitting relationship). This is because transient factors other than gas exsolution are strongly affecting the inflow performance of the CHOPS well, such that over a relatively short time span they dominate the flow behaviour. This is evident in the poor fit of field test data to a large number of Vogel curves, one of which was generated for each well, and typically only after a considerable amount of time. **Figure 7** shows three Vogel IPR curves for oil, water, and liquids generated from pressure-rate data on 2002-06-01. The first test point was on 2001-11-01. Note how almost no data points fall along the Vogel curve, despite the fact that the water cut is negligible.

Figure 7 Test Data and Vogel IPR Curve for Well 3607



This analysis demonstrated that the largest factor affecting the PI is the CHOPS process itself that continuously modifies the condition of the reservoir, such that it is always in a "transient" state. The application of the Vogel equation also assumes a zero or a constant skin factor over time. To account for damage or the effects of stimulation, the Standing equation is applied. This is based upon a Productivity Ratio (PR) or Flow Efficiency (FE)

$$FE = \frac{ideal\,drawdown}{actual\,drawdown} = \frac{J}{J'} \qquad [2]$$

where

J = stabilized productivity index, S=0
J' = stabilized productivity index, S≠0
S = skin factor

This can be rewritten in terms of a skin factor, or the Vogel equation can be reworked in terms of the base case of S=0. The revised Vogel equation is:

$$\frac{q_o}{q_{o(\max)}^{FE=1}} = 1 - 0.20\left(\frac{p'_{wf}}{p_{R(avg)}}\right) - 0.80\left(\frac{p'_{wf}}{p_{R(avg)}}\right)^2 \qquad [3]$$

where

q_o = measured stabilized productivity surface oil rate
$q_{o(max)}^{FE=1}$ = max. oil rate for FE = 1, i.e. S = 0

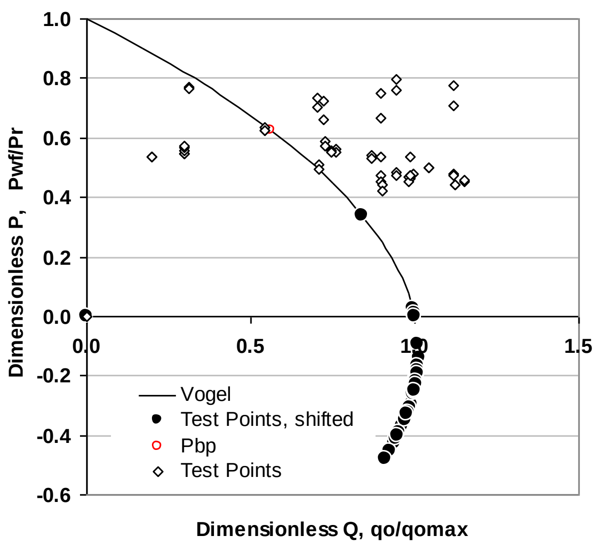
This can be expressed somewhat differently:

$$\frac{p'_{wf}}{p_{R(avg)}} = 1 - FE + FE\left(\frac{p_{wf}}{p_{R(avg)}}\right) \qquad [4]$$

where

p'_{wf} = stabilized flowing pressure in the wellbore, S ≠ 0

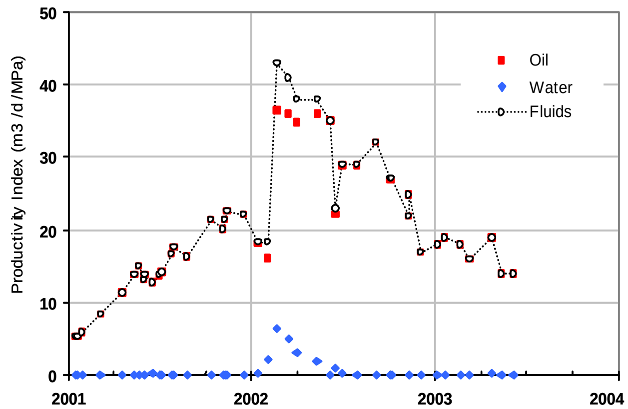
Figure 8 Inapplicable Standing Correction for a Vogel IPR Curve, Well 3607



Unfortunately, the form of these modified equations is better suited to a positive skin factor, i.e., a positive flow restriction. With the strongly negative skin factors that occur with CHOPS, i.e., FE>>1, negative values of $p'_{wf}/p_{R(avg)}$ can occur, as seen for Well 3607 in **Figure 8**. This figure corresponds to values of FE ranging up to 4.8. Negative values render the Standing correction to the Vogel equation inapplicable.

The reason for these large deviations from the Vogel equation is the large variation in the productivity index for this well. In fact, there are large variations for all CHOPS wells in KBM. The increase in the productivity index with time, corresponding to an increasingly negative skin factor, is comparable to the effect that might be expected with a highly successful well stimulation (e.g.: fracpack) or a radically different completion design (e.g.: multilateral horizontal holes from the casing). CHOPS obviously increases the productivity of the well over time, either through a process of wormhole growth into the formation, or through the growth of a high permeability and high mobility annulus around the wellbore. CHOPS increases the ease with which fluids can flow towards the wellbore, and in effect, it may be viewed as progressively reducing the skin factor. An example of this is seen in **Figure 9** in which the PI is plotted versus time for Well 3607.

Figure 9 Transient Productivity Index, Well 3607



The drop in the productivity index at the end of 2001 corresponds to a drop in the sand production rate at that time. This may have been triggered by a brief episode of water production, or by a partial sand blockage in the near-wellbore vicinity.

Clearly, the Vogel equation can be used as a conservative guide in choosing an appropriate downhole flowing pressure in order to optimize pumping efficiencies. However, only the most recent values of bottomhole flowing pressure and flow rate (p_{wf},q_o) should be used. It is inappropriate to use older data for the Vogel equation since the productivity index can change quickly and significantly. For optimal CHOPS performance, a static Vogel equation has limited use because of the variability in the skin factor associated with continued sand production. Instead, the productivity index for each test point (p_{wf},q_o) should be calculated with the Vogel equation so that the effects of changes in operating strategy can be quantified and evaluated.

Transient Productivity Index

The productivity index (PI) is a better indicator of the current health of CHOPS than the production rates. This is because the PI is largely independent of other factors affecting production rates such as pump performance, shut-ins, and downhole flowing pressure. Regardless of all other factors, a steadily increasing productivity index demonstrates that the beneficial effects of the CHOPS process is continuing to extend farther into the reservoir. When the PI fails to increase and begins to fall, it is an indicator that something is interfering with the CHOPS performance and a workover should be considered. Eventually, production rates will indeed decrease with pressure depletion, but the PI for each well should be maintained as high as possible for as long as possible to maintain maximum production rates.

Figure 10 Low Values of CHOPS Transient Productivity Indices

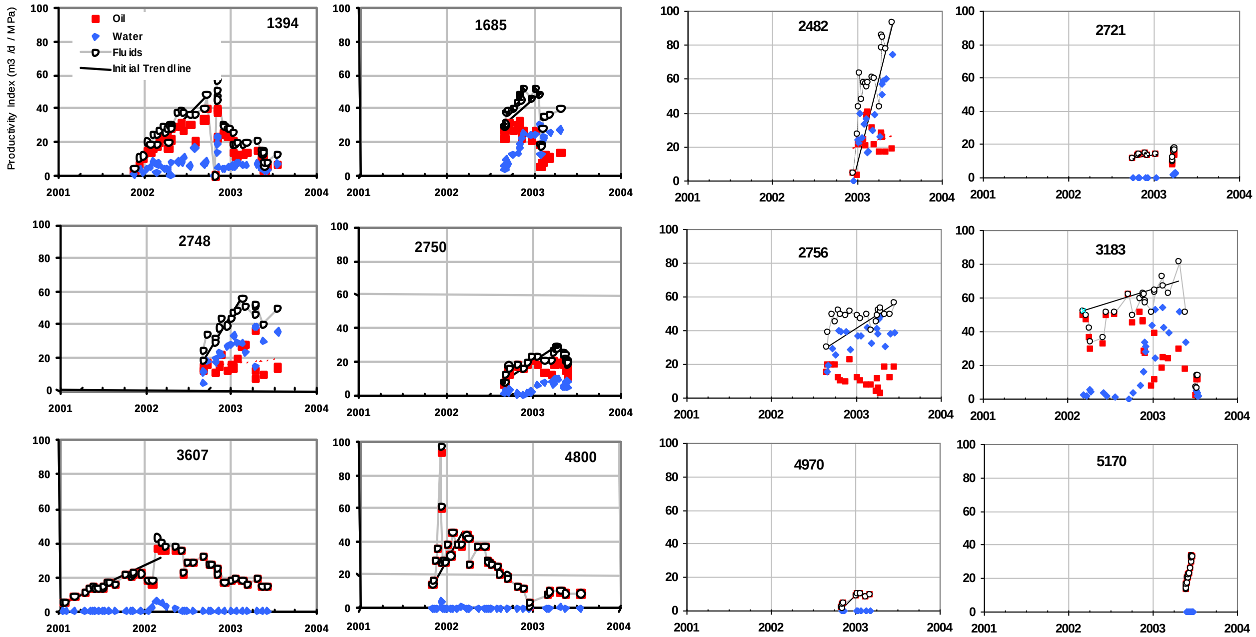
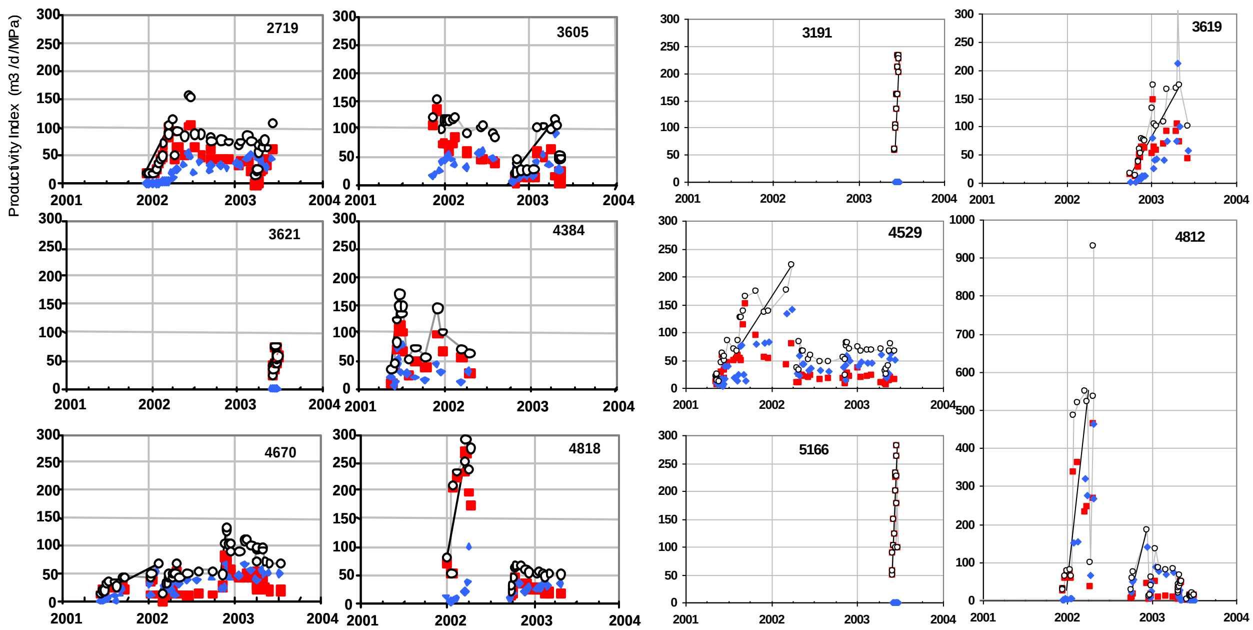


Figure 11 High Values of CHOPS Transient Productivity Indices



The transient productivity indices for oil, water, and fluids for 23 KBM wells are shown in **Figures 10 & 11** for wells with lower and higher PIs, respectively. These data only include data points with stabilized bottomhole flow conditions. In some instances, the wells were producing before the first data shown. In general, the data shown provide a good representation of the entire production history of the wells.

There is a high degree of variability in the results, reflecting the variability in production rates and sand cuts. The magnitudes of the initial PI values vary considerably, as does the rate at which PI increases. In most cases, the co-existence of water does not result in a drop in PI, and it is known from KBM data that high rates of oil production can co-exist with high water rates. However, the first occurrence of a significant water cut can reduce the PI, as seen in Well 3607. This may be a capillarity effect, where the increased water cut reduces the stabilizing effect of a water-wetted meniscus between sand grains.

The wells with the most stable behaviour, such as Well 1394 and Well 3607, show a slow increase in PI over a period exceeding a year. The PI then peaks, followed by a slow gradual decline. This is probably not optimal well behaviour. A decline in the PI can to some degree be halted and reversed by workovers. As examples, Wells 3607 and 4800 reached peaks in their PIs, then declined, but no workovers were recorded as having been done. However, Well 4670 had a few cycles of increasing PI, then decreasing PI, followed by rejuvenation with a workover. With each cycle, the peak PI attained was higher than the previous peak value, showing that the region affected by the CHOPS process continued to grow outward from the well.

Finally, the wells drilled in 2003 all have exceptional initial performance, with some PIs increased by a factor of 5 in only a few months. Continued monitoring of these wells, with workovers if necessary, should ensure their continued high performance.

Any rational analysis of production profiles must presume that CHOPS is being properly managed, and operated at optimal rates, so that remedial measures can be taken if a well becomes less productive due to non-operational causes. Two wells in identical geological and reservoir settings can have strongly divergent behaviour if the CHOPS process continues in one well and stalls in the other well without remedial workovers being taken. Monitoring of each well's PI, sand cuts, water cuts, production rates, pump efficiencies, and downhole pressures are essential for optimizing the performance of the KBM CHOPS wells. As such, workovers should be seen as opportunities to enhance well performance, and not considered as troublesome procedures to be avoided.

CHOPS Skin Factors

Conventional well test analyses of a pressure drawdown or build-up curve with time, from which "skin" values are calculated, assume that (i) permeabilities don't vary with time, (ii) permeability doesn't vary spatially, although some allow for concentric zones of different permeability, (iii) porosity and compressibility are constant in time and space, and (iv) the models assume radial flow. Because of the evolving altered zone generated during CHOPS, these assumptions are violated.

Skin calculations are based on the well tests. Skin represents a zero-thickness impedance or enhanced zone around the well, which is ill-suited to represent CHOPS, where an irregular increased permeability region has been propagated for considerable distances into the reservoir. Comparisons of well test computations based on skin equations to computations based on a zone with a variable permeability with radial distance show that transient behaviour predicted is radically different.

Skin will evolve, becoming increasingly negative with time as the CHOPS process continues, and gradually approaching the theoretical maximum value for skin. Plotting skin with time can also be used as a well management and optimization tool, but it is easier to use PI data, as these can be recalculated easily for all production times.

Effect of an Exsolving Gas Phase on Effective Permeability

In conventional oil production below the bubble point, the exsolving gas introduces a third phase that reduces the liquid relative permeabilities and production rates. In CHOPS, the foamy oil slurry approaching the well has free gas as discrete bubbles that remain mobile, rather than blocking the transmissivity of an array of pore throats.

Furthermore, the bubbles pass through pore spaces, they act in a piston-like manner to displace oil through pore throats. It also appears that a continuous gas phase is not generated for most of the life of typical CHOPS wells because the gas-oil ratio remains approximately constant, rather than increasing. The conclusion is clear: any possible negative effects that could hypothetically be generated by gas exsolution are being completely superseded by the production rate enhancements associated with sand flux, foamy oil effects, and the high permeability zone expanding from the wellbore.

CHOPS Model Description

The CHOPS model is observational and is based upon the transient productivity index for each well (**Figures 10 & 11).** A linear trendline was drawn through the data points from the onset of the CHOPS process. For Well 3605, a later time was used as the origin since the initial data seemed anomalous. For Wells 4670 and 4812, multiple events were used, as the later events appeared to correspond to the reinitialization of the CHOPS process after workovers. This comparison of PIs is an excellent method of evaluating the success of a workover: a strongly positive trendline is proof that the CHOPS mechanism has been rekindled.

The initial ramping up of the CHOPS wells is key to determining the potential of the process, since the reservoir is at virgin geomechanical conditions after drilling, and the large increase in PI is a real and quantifiable measure of the CHOPS enhancement effect on well productivity. Changes in the PI after reaching the peak are less indicative of ideal CHOPS behaviour, since many wells have not had any workovers performed to ensure that the sand production continues. Without workovers to reinitiate sand production, wells with steadily reducing PI values will operate sub-optimally.

Initial Productivity Index Behaviour

Trendlines consist of a start and an end date, which provided the elapsed time to the peak PI value. The average timespan was 153 days. This also closely corresponds to the time to peak production rates. The trendlines from **Figures 10 & 11** are reproduced in **Figure 12**, normalized to the start time.

The start point of the line in **Figure 12** provides the well's initial PI, and the endpoint provides the nominal peak PI. With these data, a value of the "folds of increase" (FOI) was calculated. This represents the factor by which the productivity index of the well is increased by CHOPS. The average value for the FOI was 6.4, which is an impressive value when compared to non-CHOPS recovery processes. The average increase in the productivity index was 1.7 $m^3/d/MPa$ each day, and this increase in PI was fairly constant for most wells.

Figure 12 Initial Productivity Indices

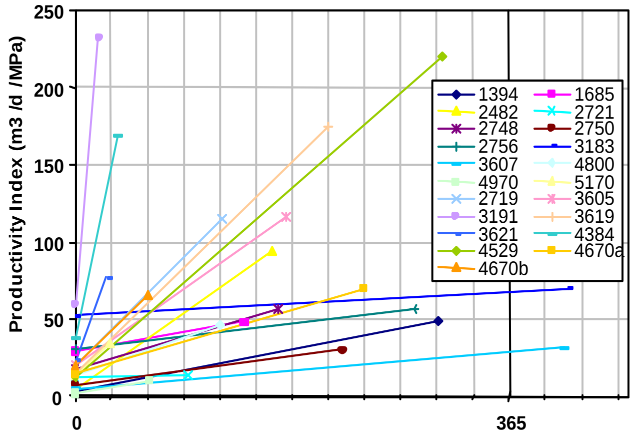
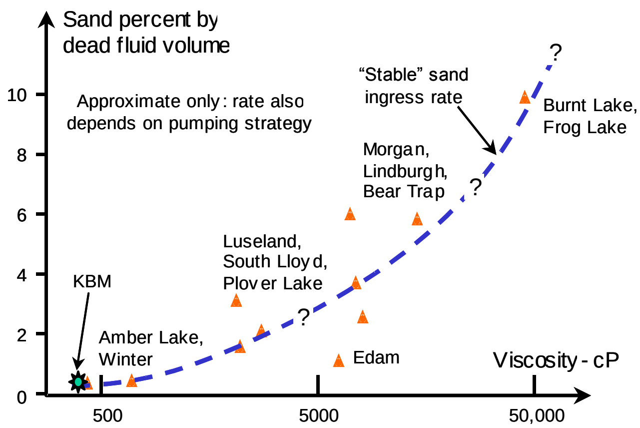


Figure 13: Approximate Sand Flux as a Function of Viscosity: Canada and KBM



Normalized Productivity Index Behaviour

The difficulty in using **Figure 12** for predictions is that it does not reflect the variations in conditions between wells. The biggest variation was net pay. However, it was seen that there was not a strong correlation between production rates and net pay. This likely reflected the differences in well operations, in that some wells were prolific producers, yet others less so, in part because the CHOPS process was not optimized with workovers to stimulate these wells. There was a strong correlation between production rates and cumulative sand production, which supports this concept. Apparently, as in Canada, sand means oil. More sand also means more oil over time because more sand generates a larger high permeability drainage zone around the well. Nevertheless, there is a "stable" sand rate for CHOPS wells to which the well converges if sand influx is not impeded.

At present, KBM's lower recovery factors are in the Jurassic, where the net pay is highest. Generally, the smaller the reservoir thickness the higher the recovery factor. Notably, when sand production stopped, productivity dropped. This was observed in some wells soon after completion, immediately after workovers intended to optimize them by installing larger pumps. After the workover, there was a step drop in sand production and well productivity. Subsequently, no workovers were done until sand production dropped off naturally.

Figure 13 shows in an approximate manner the relationship between oil viscosity and sand flux for Canadian cases where operating engineers were willing to state an approximate sand flux value. These data are not to be taken as definitive because much of the information was reported anecdotally and is not documented in the public literature. Nevertheless, it is evident that more sand is associated with higher viscosities, although it is also well known that the amount of sand can be partly a function of the exploitation strategies and the more aggressive operational practices of recent years. KBM's steady sand flux of 0.2-0.3% plots on the Canadian analogues trend.

Intuitively, two wells with identical geology, completions, and downhole flowing pressures, when operated optimally, should have production rates proportional to their net pay thicknesses. Dividing the PI values by the net pay for each well normalizes the trendlines with respect to the pay thickness (**Figure 14)**. The extreme values, young wells, and wells with low PIs but without remedial workovers were excluded, leaving a conservative subset of representative CHOPS PI values as shown in **Figure 15**.

Figure 14 Normalized Productivity Indices

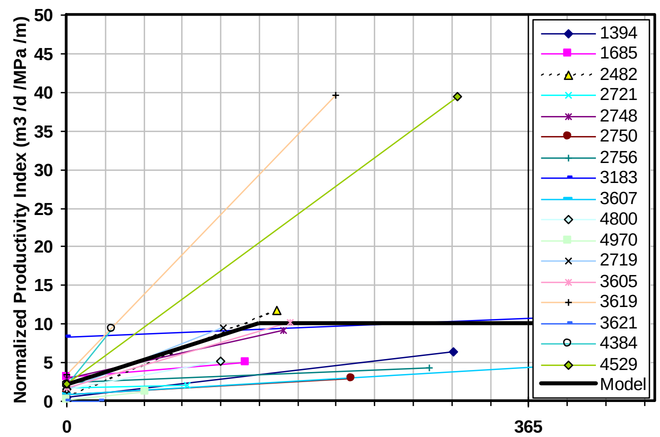
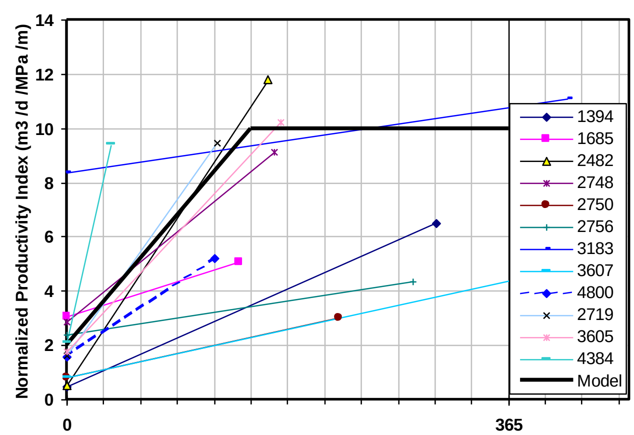


Figure 15 Normalized Productivity Indices



The CHOPS model was selected by choosing a bi-linear transient PI profile that approximated the better wells within the mid-range performance. The initial PI of 2 $m^3/d/MPa/m$ increases to 10 $m^3/d/MPa/m$ after 4 months. This represents a value of FOI of 5. In comparison, the well data show average values of 2.64 $m^3/d/MPa/m$, rising to 14.97 $m^3/d/MPa/m$ after 152 days (5 months). It is expected that the newer wells, with perforation programs designed specifically for CHOPS, will meet or exceed this 4-month ramp up of PI, as is seen in the early times of some new wells in **Figures 10 & 11**. It is expected that the plateau PI of 10 $m^3/d/MPa/m$ will be assured once more wells have perforation programs appropriate to

CHOPS, and providing that workovers are systematically conducted on wells that begin to lose productivity. Many wells will exceed this peak PI, as some already have.

This observational CHOPS model is based on the productivity index and not on production rates. This is the most sensible single parameter model to use, since variations in operating pressures and declines in reservoir pressure are incorporated directly. Gas exsolution effects would be negligible. By knowing the reservoir and bottomhole flowing pressures and the pay thickness, estimates of well production rates can be calculated.

KBM Oil Recovery Plan

New Development Area - Estimated Production Rates and Cumulative Production

The performance of KBM's CHOPS wells varies. When normalized to the pay thickness, this variation is largely due to operational differences between wells. Without a rigorous program of well workovers to stimulate producing wells with a stagnating productivity index and sand production rate, these wells will be producing sub-optimally.

Since there is a wide variation in the optimization of these wells, it is not possible to determine the current optimal production rates with certainty. However, the peak performance of each well should provide an accurate measure of the optimized capability of that specific well. An examination of the peak oil production rates in a sample of KBM CHOPS wells, divided by the net pay thicknesses provided the probable peak production rates per metre of pay thickness. In the absence of a larger database, rates were assumed to be uniform for all three Objects in KBM.

A comparison with the analogue fields provides some assurance that the estimated rates are reasonable. Production rates from Canadian CHOPS analogue fields were examined in a similar manner to determine their normalized peak production rates. As with the KBM data, it was assumed that the peak rates observed were close to the optimal rates.

The Canadian analogues produce at rates between 2.5 and 50 m^3/d per metre of net pay, with typical values of 3-4 m^3/d/m. The KBM values are expected to be 8 m^3/d/m, which is consistent with its lower viscosity of 400 cP. The notable exception is the Provost Field, which has a viscosity of 42 cP, production rates of 35 m^3/d/m, and a current recovery factor of 50%. Since KBM has a lower viscosity than the average analogue viscosity, it too is expected to have above average production rates and recovery factors.

A lower recovery is stated for Object 2, in comparison to Objects 1 & 3. **Equation 5** gives an estimate of the ultimate recovery, assuming solution gas drive and no other drive (e.g.: co-production of water, as in flooding). In it, one term is the difference in GORs: (Rsi-Rs) which in a sense quantifies the drive mechanism. The conservative assumption made was that the current GOR would be the final GOR, except in Object 3 for which a final GOR of 6 m^3/t was assumed, based on 5.58 m^3/t and 6.86 m^3/t from **Table 1**. If the final GOR of Object 2 is reduced, the recovery improves. In other words, the lower the final GOR the better, assuming that all the gas is being co-produced with the oil and not from a continuous free gas phase in the reservoir. It is expected that the final GORs of Objects 1 & 2 will be below the current GOR; however, it would be academic to speculate about an eventual GOR. The numbers used are defensible, and are conservative.

Production Rates for Different Zones, and for the KBM Field

Based on the 8 m^3/d/m, a production profile was created for the different Objects in the KBM Field. For each of the cases of Objects I, II, & III with thicknesses of 10m, 16.2m and 22m respectively, there were 3 curves generated for well spacings of 150m, 250m, and 400m (~40-acre). The rates were ramped up until the peak rate was attained, and maintained at that rate until 20% of the original oil in place (OOIP) had been recovered. At this time, a decay of 4% per month was assumed, which would account for the effects of a reduced reservoir pressure and higher water cuts. Once the recovery factors reached 30%, 23%, and 30% for Objects I, II, and III, it was assumed that the wells would be converted over to IOR processes. (**Figure 16**). Actual recoveries to date have been lower, ~10%, due to wells being shut-in after experiencing marked increases in GOR.

The rates shown are oil rates. It is expected that if water influx occurs, that the total fluid production rate could be increased to continue recovering additional oil. In practice, the economics of operating with a high water cut have to be considered.

The rates differ in magnitude because of the different net pay thicknesses for the three Objects. Object II ends sooner because the final recovery factor is smaller at 23%, whereas the others are 30%. The figure shows that the high rates expected with CHOPS in KBM will deplete the reservoir quickly for the smaller well spacings of 150m and 250m. Only in the case of a 400-m spacing (40-acre spacing) do the wells pass into a significant portion of the decline curve.

Figure 16 Predicted Single-Well Oil Production Rates for Objects I, II, and III

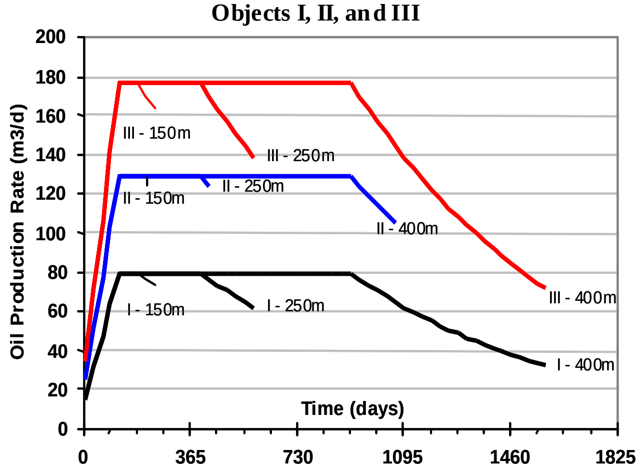
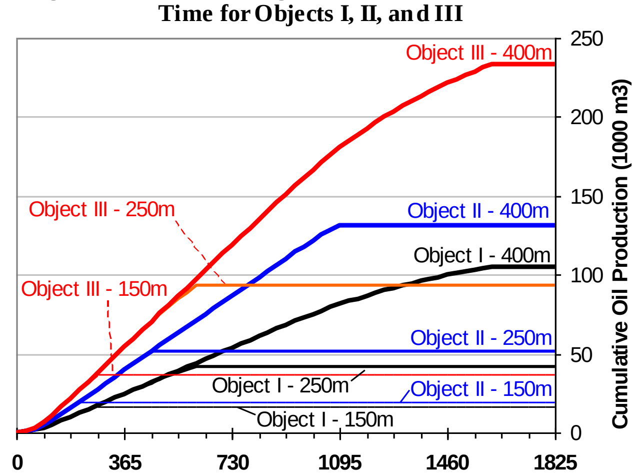


Figure 17 Predicted Single-Well Production Rates over Time for Objects I, II, and III



The cumulative recovery from a single well is shown in **Figure 17**, for the nine cases from **Figure 16**. The smaller well spacings show that they will achieve their target recovery in the order of one year. This is far less than the operating life of many current wells, however the wells now on production may be operating sub-optimally. In addition, water influx will delay the recovery of oil. Additional oil volumes swept by the produced water will also increment the recoverable oil, unless the water rates become uneconomically high.

Predicted Project Production Patterns

The production pattern for CHOPS wells should consider three factors: the orientation of the major horizontal stress, the structural geology, and post-CHOPS processes.

The CHOPS process will favour the progress of the disturbed zone of sand, whether a wormhole or an annulus of disaggregated sand, into areas and zones where the sand is most likely to fail. CHOPS will progress into horizons within the reservoir with the lowest strength, since they will disaggregate easier. The variation in strength is likely strongly related to geology, therefore it is conceivable that the process will preferentially grow into one facies, rather than uniformly. CHOPS will favour growth towards zones with higher reservoir pressures, since the higher hydraulic gradients in these directions will be highest. This effect reduces the tendency for any bypassed oil, as the process preferentially grows towards these zones. CHOPS will preferentially grow towards areas where the sand stresses, in combination with the pressures, flow gradients, and sand strength, will result in failure. In a reservoir with an anisotropic stress field, such as KBM, this could alter the well spacing on a directional basis. Anecdotal evidence is that CHOPS growth is highest parallel to the maximum horizontal stress direction. In KBM, this is a NNW-SSE orientation in the Cretaceous (with a possible rotation to NE-SW in the Jurassic). As such, well spacing in this direction could be increased.

The structural geology is critical when planning well locations. The KBM Field is not highly deformed, yet there is compartmentalization along the southern edge of the Eastern Pericline, as shown in **Figure 2**. The faults radiating out from the structural high have bisected the reservoir horizons at the faults. Differential fault throws have truncated the reservoir horizons at these faults, some of which are transmissive while others are sealing. For the purposes of CHOPS, the position of the fault is not that important, as the process itself and the solution gas drive mechanism will tend to exploit areas of the reservoir at virgin pressures.

However, subsequent IOR processes may not be able to access oil because of poor well locations with respect to sealing faults. When selecting well locations, geology should take precedence over geometric uniformity. This is important if subsequent steamflooding or waterflooding are planned.

From the previous analysis, the current well spacing of 150m is small if CHOPS alone is being considered. A well spacing of 400m will reduce the oil rates per hectare; however, more area can be drilled for a given number of wells. Additionally, a 400m spacing will have increase the economic life of each well during the initial CHOPS recovery process. Infill drilling could be done later if necessary, particularly if an IOR process requires closer spacing. Drilling newer wells at a spacing of 400m was recommended, geology permitting. This was comparable to some of the analogue fields considered in this report.

Current spacing in the East-West new drill areas is 300 meters, with infill drilling down to 150m for optimal EOR recovery.

Sand Volumes Predictions

Sand cuts, with the exception of the initial period when the wells come onto production, are stable at approximately 0.1% by volume of the produced fluids. The initial period is relatively brief and initial rates are low, so the higher cuts of up to 7% will not have a significant effect on cumulative sand production. Recurring workovers may increase total sand volumes.

More importantly, when a routine of well workovers on producing wells is established, sand production rates will be higher than at present. From the behaviour of existing CHOPS wells in KBM, an average sand rate of 0.2% should be expected. Continued monitoring of CHOPS wells will permit a more accurate estimate in future.

Workovers should be done whenever operations fail, such as a pump failure, or when sand cuts and the PI values indicate that the CHOPS process requires rejuvenation.

Predicted Recovery Factors

Solution Gas Drive

Gas exsolving from the heavy oil provides the dominant drive mechanism for oil production. With the fall in reservoir pressures emanating away from the producing wells, gas bubbles continually exsolve and expand in the pore space, which provides pressure support .and displaces oil to the well.

The standard equation for the fractional recovery of oil in a volumetric, undersaturated reservoir is:

$$r = \frac{N_p}{N} = \frac{B_o - B_{oi} + B_g\left(R_{si} - R_s\right)}{B_o + B_g\left(R_p - R_s\right)} \qquad [5]$$

where

r = oil recovery, fraction
N = initial reservoir oil, stock tank volume
Np = cumulative produced oil, stock tank volume
Gp = cumulative produced gas, stock tank volume
Bo = formation volume factor
Boi = volume factor, formation, initial
Bg = gas volume factor
Rs = gas:oil ratio (GOR)
Rsi = GOR, initial
Rp = net cumulative GOR = Gp/Np

This must be used with caution for two reasons. Firstly, at KBM there is evidence of water influx on the southern flank, which is an additional and beneficial drive mechanism. Secondly, this equation assumes that exsolved gas is accumulating within the reservoir, which will support the pressure and displace the oil towards the well as the pressure falls. In contrast, the CHOPS process produces the discrete bubbles entrained in the foamy oil. This accelerates the CHOPS process and production rates since the expansion of the bubbles within the foamy oil reduces the effective viscosity of the oil and pushes the oil towards the well. Only very late in the life of a CHOPS well is there a rise in the GOR, with occasional gas slugging, indicating that a continuous gas phase has finally developed in the reservoir.

The equation is instructive with respect to the gas:oil ratio, GOR or Rs. To maximize recoveries using solution gas drive, the denominator must be minimized. All parameters in the denominator are PVT properties of the oil or gas, with the exception of the net cumulative GOR: Rp. This represents the cumulative GOR of the produced fluids.

Higher amounts of produced gas reduce the recovery in a volumetric reservoir. This is because the gas is no longer in the reservoir to expand, which displaces the oil by occupying more of the pore space. Production rates would also be lower, since the expanding gas cushions the pressure drop resulting from production. Preserving the gas in the reservoir also optimizes the CHOPS process by permitting "foamy oil" flow of discrete gas bubbles within the high viscosity oil. This lowers the effective viscosity of the oil, and accentuates the sand production.

The CHOPS process should not be producing gas with oil above the GOR in the reservoir, which may drop slowly if immobile gas bubbles form in the pore space due to the drop in reservoir pressure. Producing CHOPS wells at the current GOR will minimize the net cumulative produced GOR, Rp. Over the life of the CHOPS well, the Rp value should approximate the average GOR over time.

If we accept the limitations of the equation, and assume that the gas is being co-produced with the oil at the current GOR, then some assumptions about the primary recovery with CHOPS can be made. It was assumed that the produced gas was equal to the initial GOR, and that the conversion to IOR would occur at 1 MPa. By using the high value of Rp, it prevents a gas cap accumulation. The predicted recoveries with CHOPS range from 13% to 20%. If the GOR at conversion to EOR is even lower than the assumed values, the recoveries will improve.

Water Drive and Waterflooding

One assumption made in the previous section was that water was not being co-produced. This is clearly not the case, as some of the most prolific CHOPS wells in KBM are producing oil at substantial rates with high water cuts (**Figures 10 & 11**). Wells continue to produce at high oil rates even when water rates exceed them.

Clearly, the source water is not the irreducible water saturation. Instead, water influx is increasing, and displacing oil in the pore space. Eventually, water will displace all the mobile oil, however the economic limit of this process will certainly occur once the water cut exceeds the operating costs of the well and the water disposal.

An estimate of the ultimate recovery expected with this can be made using the KBM oil/water relative permeabilities. The initial water saturation is Sw=0.15, which represents the irreducible water saturation. At the other extreme, oil becomes immobile at an oil saturation of So= 0.53125 where Sw=0.46875. The increase in water saturation of 0.31875 or approximately 30% represents the amount by which water will displace the oil. Given that the recoveries estimated for the solution gas drive were solely for the effects of expanding hydrocarbons, these waterflood recoveries are incremental. Realistically, additional recoveries will be a fraction of this, but would certainly approach an additional 10% to 15% assuming that no zones are bypassed.

Compaction Drive

Reservoir compressibilities were calculated from sonic logs. Given that the change in the reservoir's effective stress will be equal in magnitude to the drop in reservoir pressure from 4MPa to 1MPa, the formation would be expected to compress by 0.0003, or 0.03%. If the porosity were assumed to be 30%, that corresponds to a pore compressibility of 0.1%. The incremental oil production would be 0.1% multiplied by the oil saturation of So=0.75 to 0.85. The incremental oil production from compaction, in this instance, is insignificant.

Rapid vs. Slow Development

The choice of the rate of development depends on many factors, but key amongst these is the desired production rate.

Using the production profiles from **Figure 16**, an estimate of the production rates for the three Objects was calculated. This assumed that one new well was drilled per month, so that the cumulative production increased until the first well began to reach the end of its life, based upon the recovery factor. The results of this analysis are presented in **Table 4**:

These rates are intended as a guide to planning. As an example, if wells are to be drilled at a rate of four per month, the above rates should be factored by four. Conversely, if a desired field production rate were known, it can be divided by the rates above to determine the number of wells that must be drilled each month to maintain production.

Table 4 Peak Production Rates by Object

	Object I	Object II	Object III
Peak Rate per Well (m^3/d)	80	130	178
Cumulative Peak Rate (m^3/d)	1554	2525	3458

Conclusions

The KBM case shows that CHOPS can be successfully applied to lower viscosity oils. Our conclusions and recommendations:

- accounting for viscosity differences, KBM wells are behaving as expected, in comparison to Canadian data
- develop and maintain excellent quality geological models
- reduce uncertainty in core and log parameters
- good records of all oil, water, gas and sand production are essential for problem diagnosis; well history is vital
- encourage, sustain and reinitiate sanding when possible
- a good sand management system must be implemented.
- pump optimization should always use recent data since CHOPS continually alters downhole conditions
- continually monitor well PIs to quantify CHOPS effectiveness and well performance, and as a tool for making workover decisions
- a predictor model has been developed using the PI approach; it must be refined in specific field cases
- operating far below the bubble point is clearly the best operational practice for heavy oil CHOPS wells; flow enhancements outweigh any negative aspects associated with relative permeability reductions.
- studies of EOR technologies are required for post-CHOPS, including:
    - gravity-drainage thermal processes for thicker zones
    - water or polymer flooding for thin zones

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NOMENCLATURE

Bg = gas volume factor
Bo = formation volume factor
Boi = volume factor, formation, initial
CDC = Central Development Committee
CHOPS = cold heavy oil production with sand
CSS = cyclic steam stimulation
GOR = solution gas to oil volume ratio m^3/m^3

Gp = cumulative produced gas, stock tank volume
J = stabilized productivity index, S=0
J' = stabilized productivity index, S≠0
KBM = Karazhanbas Field (Karazhanbasmunai)
N = initial reservoir oil, stock tank volume
Np = cumulative produced oil, stock tank volume
PCP = progressing cavity pump
p'_{wf} = stabilized flowing pressure in the wellbore, $S \neq 0$
P_{bp} = bubble-point pressure
$p_{R(avg)}$ = average reservoir pressure
p_{wf} = measured stabilized flowing pressure in the wellbore
Δp = change in pressure
q_o = measured stabilized productivity surface oil rate
$q_{o(max)}^{FE=1}$ = max. oil rate for FE = 1, i.e. S = 0
q_x = measured stabilized productivity surface flow rate
$q_{x(max)}$ = maximum producing rate q_x of liquid "x" at the maximum drawdown, $p_{wf} = 0$
R_F = oil recovery factor, fraction
Rp = net cumulative GOR = Gp/Np
Rs = gas:oil ratio (GOR)
Rsi = GOR, initial
S = skin factor
SAGD = steam-assisted gravity drainage
t = tonne
WOR = volumetric produced water to oil ratio
x = Vogel subscript; substitute for oil, water, or liquids
σ_H = maximum horizontal stress
$\sigma_{h,}$ = minimum horizontal stress
σ_v = vertical stress
"~" = approximately

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