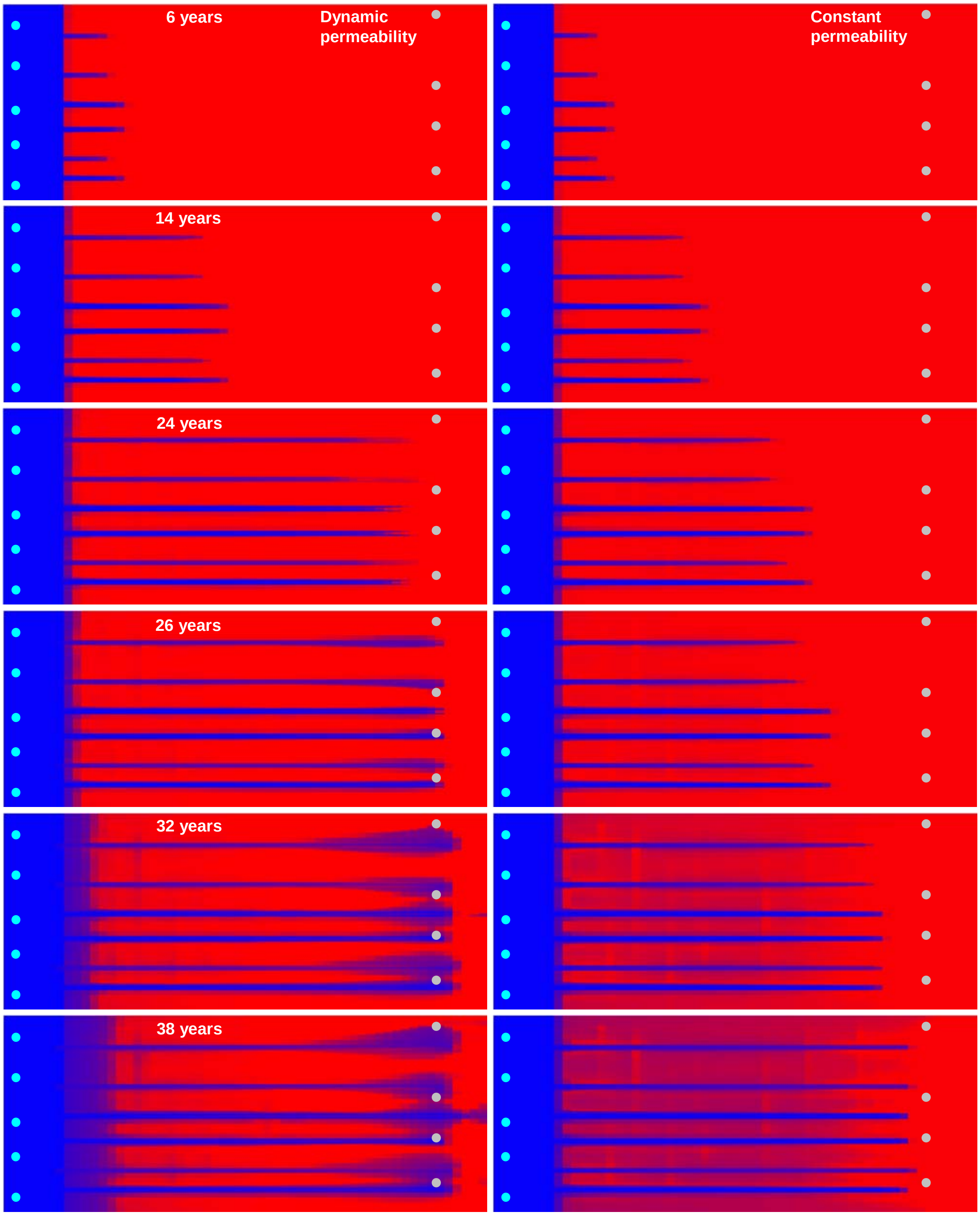

Fig. (12). Water saturation in a Ness 2 grid layer containing 50 m wide channels, LC case. Water injectors to left (West), Upper Brent oil producers to right (East) (light gray). Blue is water, red oil.

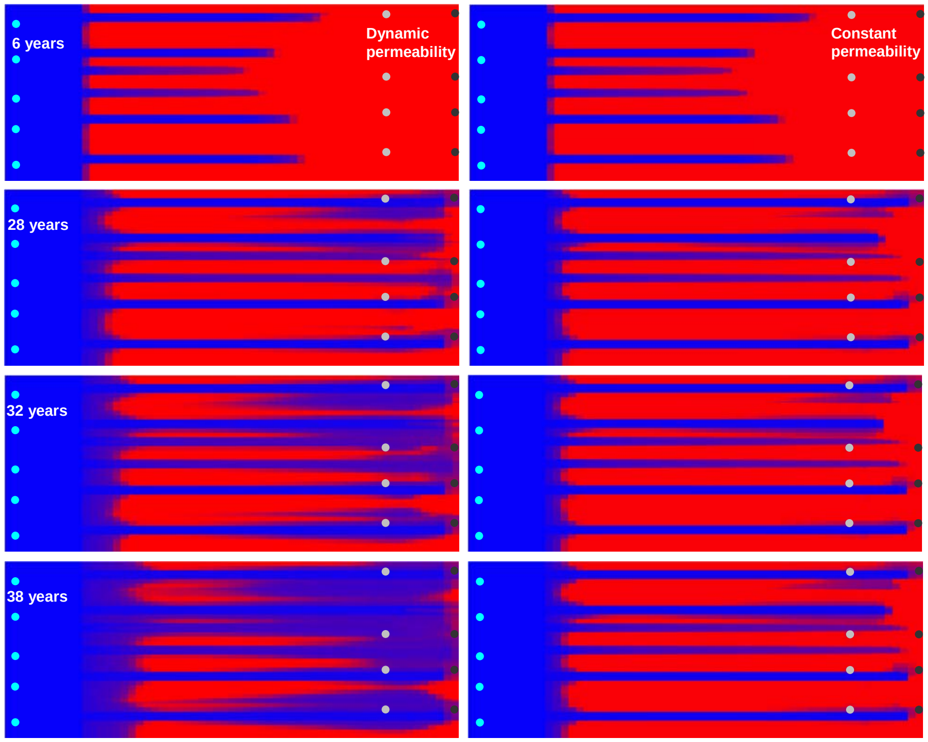

Fig. (13). Water saturation in a grid layer in upper Etive, containing 100 m wide channels, at selected times. Water injectors to left (West), oil producers to right (East) (Upper Brent producers light gray, Lower Brent producers to far right). Blue is water, red oil.

We infer that for such a compartmentalized reservoir, each compartment behaves individually and must be treated as isolated. The need for oil producers in the western fault block is e.g. obvious.

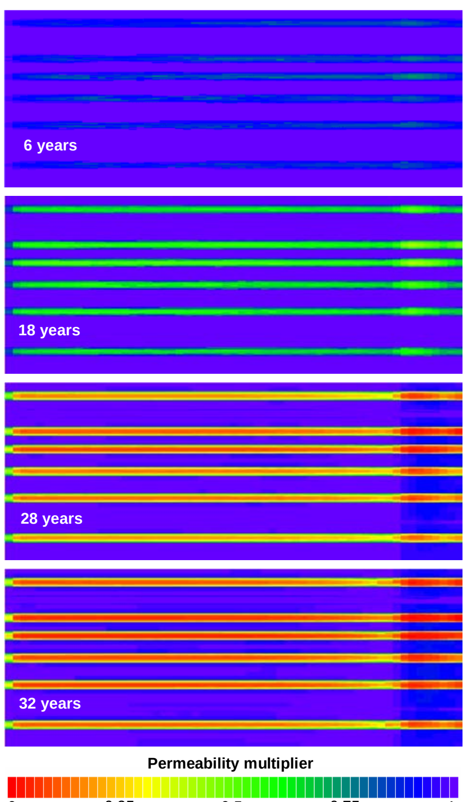

Fig. (14). Permeability multiplier corresponding to Fig. (**13**).

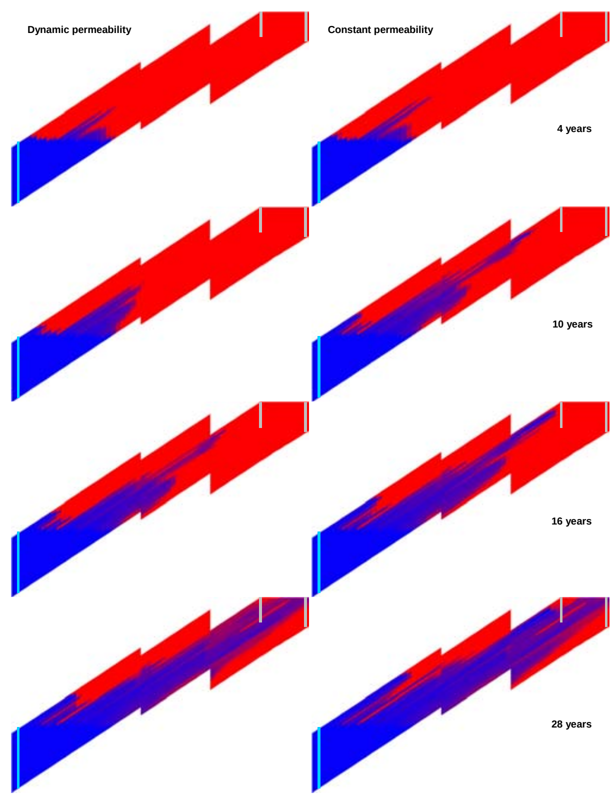

Fig. (15). Water saturation in a W-E X-section w. faults. Large Contrast, 15 m wide channels. Injectors to West (light blue), producers to East (gray). Water blue, oil red.

Production

Some examples of production data are shown in Figs. (**16–21**).

A good measure for how well different regions are produced is the *oil efficiency*, which is the ratio of oil removed to initial oil in place in the region. Figs. (**16–19**) show this parameter for some channel formations for various material contrasts and channel widths. Cases with 15 m channels are shown in Fig. (**16**).

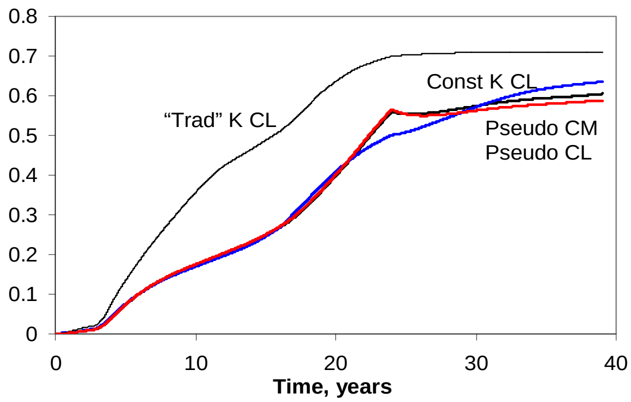

Fig. (16). Oil efficiency in region Ness 2 channels, 15 m channels.

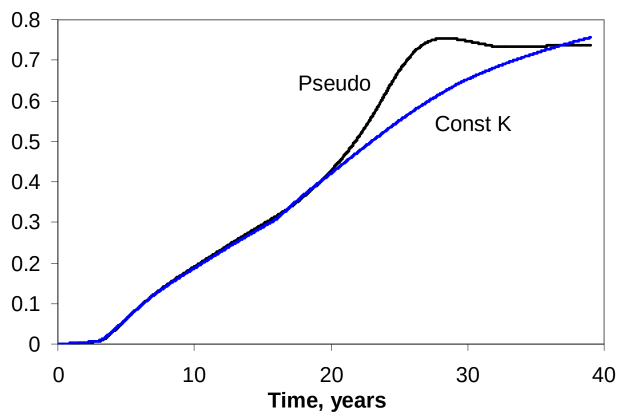

Fig. (17). Oil efficiency in region Ness 2 channels, case CL, 50 m channels.

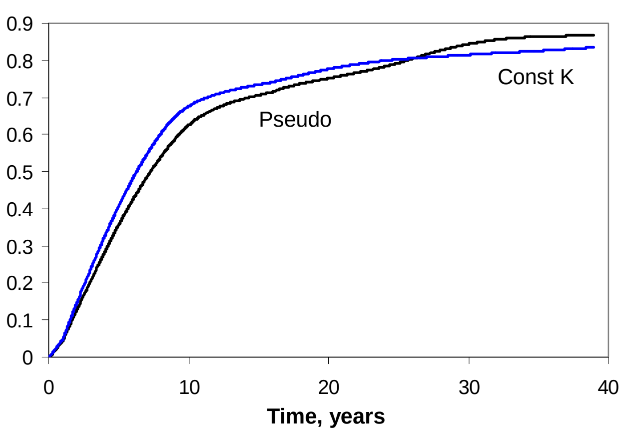

Fig. (18). Oil efficiency in region Etive channels, case CL, 100 m channels.

Firstly, we see very little difference between the CM and CL cases, which was observed in most cases and regions. Hence the material geometry appears to more important than the contrasts, if only the contrast is sufficiently large. Compared to the case with constant permeability there is a small but significant boost in oil efficiency when the blowdown is commenced. Lastly, a case with "traditional" permeability multipliers (a single permeability multiplier table for this channel material) is included in the figure for comparison. This case deviates significantly from the others, which also is generally observed. This manner of modeling the permeability multiplier should hence be avoided.

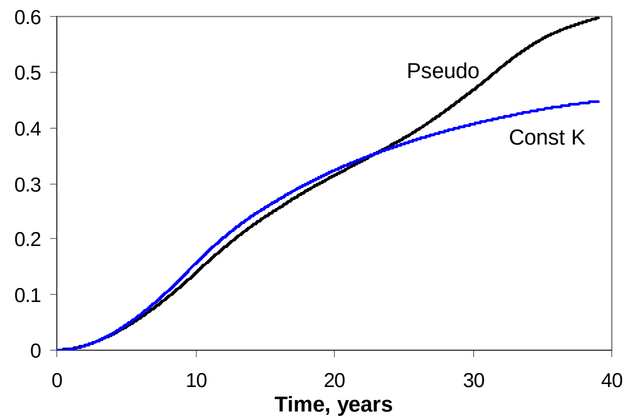

Fig. (19). Oil efficiency in region Etive background, case CL, 100 m channels.

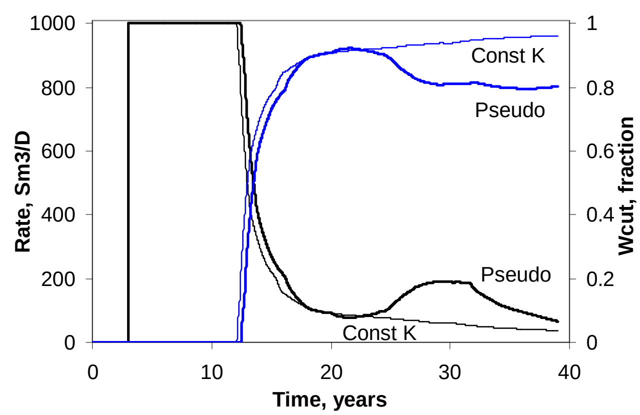

Fig. (20). Well oil rates and water cut, central Upper Brent Well, 50–100m channels, case CL.

The corresponding CL case with 50 m channels is shown in Fig. (**17**). The same kind of production boost can be seen, but more pronounced, reiterating the dependency on channel width.

A slightly different kind of response is seen in Figs. (**18**) and (**19**). Here the efficiency boost in the channel facies (Fig. **18**) is smaller than in the previous examples. However, a significant efficiency increase is seen in the associated background material, Fig. (**19**). Such an effect was not seen in the background material corresponding to Figs. (**16**) and (**17**). This can probably be explained by that the Etive background (Fig. **19**) has higher permeability than the Ness 2 background (Figs. **16** and **17**).

The results in Fig. (**19**) are more in accordance with expectations; by homogenization the lower-permeability material should be better swept than without homogenization.

An example of oil and water production rates from a well is shown in Fig. (**20**), which depicts oil rate and water cut in one of the central Upper Brent producers. In agreement with expectations oil rate increases and water production is reduced during the pressure blowdown period. This is due to the reduced water cycling through the channels after homogenization.

Looking at total field production rates, Fig. (**21**), we notice the expected production boost when at the start of the blowdown period. Perhaps surprising, the different cases are very similar, (except for the "traditional" case, where permeability reduction is modeled incorrectly, and is shown for comparison only). This is probably partly due to the way the simulator allocates production, and partly to the production scheme; we have not made any attempts to optimize well operations in these simulations, which certainly would have been done in a real case.

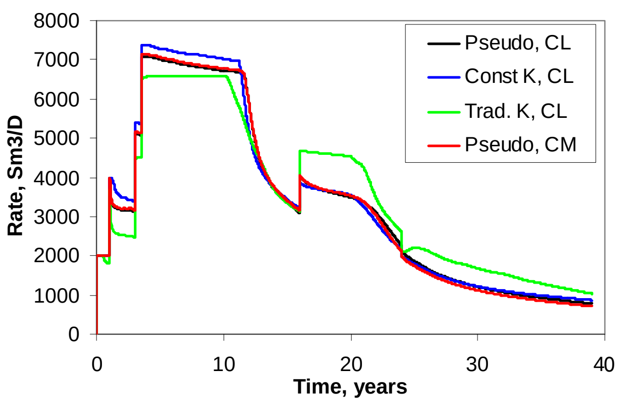

Fig. (21). Field (total) oil rates. 15 m channels.

The Figs. (**16–21**) must be read as the difference in results as a consequence of how the compaction and permeability is modeled in the reservoir simulator. The reservoir description and production strategy are regarded as fixed. The focus in this paper is on the modeling strategy, and possible consequences of simplified compaction / permeability modeling.

However, Fig. (**22**) has been included as a reference case, showing the effect of the blowdown as such. The blowdown gives an instantaneous production boost, and the oil rate is maintained at a higher level than the no-blowdown case for about five years.

DISCUSSION

It has been demonstrated that in an environment comprised of a mixture of weak and strong materials, production at reduced pressure in many cases can have a positive effect on recovery by reducing water cycling and spreading injection water from high-permeability regions to neighboring, lower-permeability materials. The extent of the high-permeability material, the permeability contrast between the materials, and the initial permeability in the background material are all important factors for the ensuing sweep improvement The simulations demonstrate the expected positive effect *locally*, i.e. in the vicinity of the large-contrast domains. However, in most of the studied cases, the total field production was not significantly affected. This is most readily explained by the model setup; a significant part of the model volume contains clean sandstone where the permeability reduction is smaller and homogenization absent. When production is increased in the high-contrast regions, a corresponding reduction is seen in other regions, maintaining total production rates. This feature was more evident in models with good to moderate vertical conductivity, as the low-permeability regions then were more easily produced by water flux from neighboring layers above or below. In a real reservoir production scenario the well rates would have been optimized to exploit all local production boosts, and similarly shut off e.g. connections with high water-production. Hence the local production improvements which this study clearly shows the potential for, will result in real gain, primarily by reduced water production, but often also by an increase in oil production.

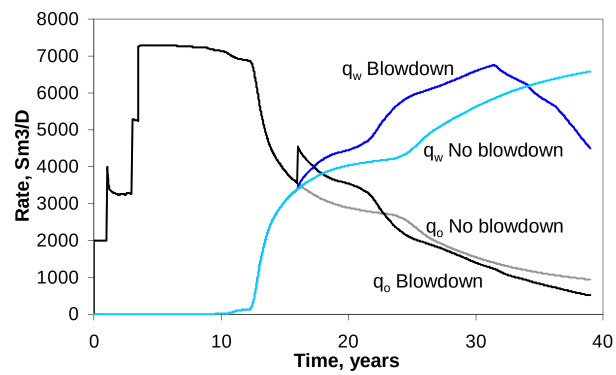

Fig. (22). Field oil and water rates, case CL, 50–100m channels with and without blowdown.

The studied simulation models are clearly simplifications of real reservoirs, which contain a multitude of contrasting materials, often on a small scale. Hence, the local effects which were detected in this study may occur to a much larger extent in practice. I.e. the qualitative results in this study are probably more significant than e.g. the field production curves in Fig. (**21**).

Note also that the goal of this paper is not to investigate the benefits or drawbacks of the blowdown process itself, but to study different modeling options during such a process. It is for example totally unrealistic to operate with a blowdown period of 22 years; in reality, the duration would be a few years at most. Some of the observations are probably valid independent of the time scale, but according to the simulations it does take some (simulated) time to establish a sufficiently low average pressure, which is needed for some effects to take place. On a shorter time scale, the low-pressure domains are concentrated near the production wells.

CONCLUSION

1. Permeability reduction in sand or sandstone reservoirs can be large even at moderate pressure drawdown.

2. Compaction and permeability reduction can have significant impact on fluid flow in a large class of reservoirs.

3. Weak, moderate, and strong materials behave differently when loaded, and by pressure reduction the ini-

tial permeability distribution can be altered in a fashion that has large impact on the flow pattern.

4. The deformation (and hence compaction) of a reservoir is more complex than the traditional dependency on pressure typically used in flow simulators, and must be calculated by a stress simulator. However, once one rock mechanics simulation has been carried through, further studies can be done by pure flow simulations, provided the pore volume multiplier tables are generated to honor the strain calculations by the stress simulator.
5. Material behavior in a depletion or pressure blowdown process can contribute positively to recovery in many kinds of reservoirs.

The factors which were found to have the largest impact on actually changing recovery or flow pattern, are:

- permeability contrast between the strong and weak materials
- initial absolute permeability in the low-permeability materials
- the permeability versus load relationship
- geometry, i.e. extent and distribution of weak and strong materials
- overall vertical reservoir connectivity

Glossary

PVM	pore volume multiplier
Tmult	transmissibility multiplier
CL	case: large permeability contrast between channel and background material
CM	case: moderate permeability contrast

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