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Productivity and Injectivity of Horizontal Wells

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Department of Petroleum Engineering
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Stanford, CA 94305

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Quarterly Report

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Introduction

As this is our first quarterly report of the second year of the project, it is appropriate to reiterate the major tasks of the project. A summary of these tasks is given below. In this second year we are progressing with strong activity on the continuation of tasks 1, 2 and 3 from the first year. In addition, start-up effort is being placed on Tasks 4 and 8.

TASK 1: Modeling Horizontal Wells-Establish detailed 3D methods of calculation which will successfully predict horizontal well performance under a range of reservoir and flow conditions. Review both commercial simulators and simple inflow performance relationships used by the industry. Investigate the sensitivity of various parameters on the performance of horizontal wells. Develop modeling techniques and computer codes based on generalized 3D-flexible gridding techniques which can be incorporated into reservoir simulators.

TASK 2: Reservoir Characterization-Investigate reservoir heterogeneity descriptions of interest to applications of horizontal wells. Develop averaging techniques in 3D which will adequately compute effective single phase and two-phase directional permeabilities within the variable gridding characteristics of the model developed in Task 1. Perform sensitivity studies of the averaging technique to uncertainties in the heterogeneity distribution.

TASK 3: Experimental Planning and Interpretation-Critically review technical literature on two-phase flow in pipes and the correlation of these results in terms of their relevance to horizontal wells. Perform sensitivity studies to choose parameter spaces of interest for some typical field conditions, using oil companies' advice. Plan key experiments to investigate sensitivity to parameter variation including inflow distribution, completion variations, void fractions, etc. Perform data analysis including flow pattern distribution, scaling, dependence on perforation intervals, confidence levels, etc. Revise two-phase flow correlations where necessary to produce new methods of calculation for two-phase pressure drop in horizontal wells. Incorporate this capability in Task 1 above.

TASK 4: Pseudo-Functions-Define methods for determining 3D coarse grid approximations (e.g., pseudo-functions) for horizontal wells using the more refined calculations developed in Tasks above. Evaluate the robustness of the coarse grid approximation in example field scale calculations.

TASK 5: Develop Multi-Well Models-Work towards longer term goal of development of detailed multi-well models interactively coupled to large scale reservoir simulation using multiple parallel facilities.

TASK 6: Test Model with Field Examples-Examine performance of new models and their validity. Seek oil company advice and field experience in a variety of reservoir applications. Rationalize uncertainties against departures between prediction and observation and improve modeling capability.

TASK 7: EOR Extensions-Provide enhancements to the model to handle compositional effects for miscible displacements, thermal effects for steam processes, and combustion processes.

TASK 8: Application Studies-Examine illustrative reservoir engineering opportunities for horizontal wells using oil company advice and evaluate their predicted performance vis-a-vis vertical wells. Evaluate benefits of hydraulic fracturing and recompletion techniques in horizontal wells. Assess possible relative advantages for illustrative EOR scenarios.

Activities related to Tasks 1, 2, 4, and 8 have been carried out in this period which are briefly described below.

Summary of Technical Progress

A number of activities related to the four tasks listed above have been carried out in the last three months. A summary outlining these efforts is presented below followed by a brief description of two of the principal activities in the subsequent sections of this report:

- Extensive sensitivity studies, based on reservoir simulation, have been performed on a field example to assess the effects of wellbore friction, inflow, skin, length and diameter of the well, etc. on the productivity of a horizontal well.
- We have launched a new phase of the project on developing models for scale-up and coarse grid pseudo functions for horizontal wells in heterogeneous reservoirs. The available methods have been applied to an example problem and their performance and limitations have been analyzed.
- We are in the process of developing a new analytical solution for the coning and cresting critical rates for horizontal wells.
- All the experimental data obtained at the Marathon Oil Company is being compiled in an appropriate computer data bank format. Parallel to this activity, a large data base is being created at Stanford which will contain most of the two-phase flow measurement data in the literature. These two resources will then be employed in testing our newly developed general mechanistic model for two-phase flow.

Sensitivity Studies of Wellbore Friction and Inflow for a Horizontal Well (Tasks 1,8)

**(This study is being conducted by Lillian Berge,
A Visiting Scholar from Norsk Hydro)**

The importance of modeling frictional pressure drop in horizontal wells has been discussed in the literature. Whether friction is significant for the well behavior or not, depends very much on the permeability level and thereby the pressure drawdowns created. To gain more understanding about wellbore friction and how it interacts with inflow to the well, several

Table 1: Rock and Fluid Properties used in the Sensitivity Example Problem

Initial pressure at GOC	158 bara
Oil viscosity	1.3–1.5 cP
Gas viscosity	0.016–0.020 cP
Oil formation volume factor, at initial pressure	1.17 Rm^3/Sm^3
Gas formation volume factor, at initial pressure	0.0065 Rm^3/Sm^3
Connate water saturation	7%
Critical gas saturation	10%
Residual oil saturation to water	25%
Residual oil saturation to gas	7%
Max. relperm to water in presence of residual oil	0.28
Capillary pressure	none

reservoir simulations[1] have been done based on a detailed field example where wellbore friction is expected to play a dominant role.

The case under study is a horizontal well of length 500 meters producing from a thin oil zone in a high permeability reservoir, which has a large gas cap and bottom aquifer. The reservoir is a poorly consolidated, layered sandstone, with mostly high porosities (30–35% in the clean sands) and anisotropic permeabilities, with ratios $k_x/k_y = 1/3$ and $k_z/k_y = 1/10$ in the model. A heterogeneous distribution of sand properties was used similar to that set up by the operating oil company. The maximum horizontal premeabilities (k_y) are in the order of 2000–20000 mD, in a direction normal to the well. Most of the large bottom aquifer has been given low vertical permeabilities (1–2 mD), as a result of averaging permeabilities over a sequence with some tight zones in between. The upper part of the aquifer has a 20 meter residual oil zone. One set of rock relative permeability curves is used for the entire hydrocarbon zone, while for the aquifer (below residual oil zone) the relative permeability to water is assumed to vary linearly with water saturation. Some fluid and rock properties are given in Table 1.

In this single well model the reservoir is horizontal, and permeabilities are constant within each layer. The horizontal well section is also modeled as being perfectly horizontal, to be able to easily isolate the effects of wellbore friction. The well is completed in the lower part of the 20 meter thick oil zone, 4 meters above the oil-water contact, and experiences both gas and water coning. To limit sand production, the horizontal section is completed using a prepacked screen, which has a 6 inch inner diameter and the absolute roughness is estimated to be 1 mm.

A production period of 7 years is simulated, with a target oil rate of 2500 Sm^3/D, and a maximum gas rate of 2E+06 Sm^3/D. The minimum bottomhole pressure is set to 150 bars (10 bars lower than initial pressure at the well). At the top of the reservoir 70% of the produced gas is reinjected. This schedule is made to go through different typical phases of the well's actual production history within a relatively short period, and still have appropriate production rates.

A total of 17 sensitivities were simulated, varying one parameter at a time. A summary of all the cases investigated is given in Table 2 while the simulation results are presented in Table 3. Key parameters like the friction factor (roughness) and pipe inner diameter have

[1] Using the ECLIPSE simulator.

Table 2: List of the Sensitivity Cases Considered

Case no.	Description
1	Reference case, including friction, $\varepsilon = 1$ mm (prepacked screen)
2	Reference case, without friction
3	Smooth pipe, $\varepsilon = 0.05$ mm (new liner) [2]
4	Synthetic high roughness, $\varepsilon = 10$ mm, during free gas production
5	Smaller inner diameter, $ID = 5$ inches
6	Larger inner diameter, $ID = 7$ inches
7	Longer well, $L = 1000$ meters
8	Skin factor $S = 3$, constant along the well
9	Variable skin, $S = 5$–1, largest at heel
10	Skin factor $S = 10$, constant along the well
11	Local flow barriers (stochastical calcite (shale) realization)
12	Permeabilities reduced by a factor 10 ($k_y = 200$–2000 mD)
13	Permeabilities reduced by a factor 100 ($k_y = 20$–200 mD)
14	"Homogeneous" case, avg. $k_h = 7000$ mD, avg. $k_v = 1400$ mD [3]
15	"Homogeneous" case, avg. $k_h = 1500$ mD, avg. $k_v = 300$ mD [4]
16	No residual oil zone in the aquifer, (increased water mobility)
17	Maximum gas rate 1E+06 Sm^3/D

been changed, and one run has been made with a longer horizontal well. Also, the skin factor along the wellbore has been manipulated. Lower levels of permeability are investigated, along with a few attempts to "homogenize" the reservoir, using constant average values for k_h and k_v for the entire reservoir. Liquid rates vary when changing the permeability, and two different maximum gas rates are compared.

Typically, water breaks through immediately because of the proximity to the water zone. The shape of the developing gas cone depends on how drawdown varies along the well, which is determined by the pressure profile within the wellbore (i.e. the frictional pressure drop along the well). Hence, the time to gas break through shows a large variation as drawdown along the well is changed. With no friction in the wellbore free gas breaks through over a large section at the middle of the well. This is also the situation when permeability is reduced to a level where pressure drawdown becomes much larger than the frictional pressure drop. For all other cases investigated, the gas break through occurs at the heel, where the maximum drawdown is. The well length over which the free gas enters may change with the drawdown / inflow distribution for each case, and is here usually limited to the first 100–200 meters closest to the heel. The gas cone gradually widens (and elongates) and gas rate increases rapidly to a specified maximum which marks the end of the oil rate plateau (see Fig. 1). On bottomhole pressure control, available drawdown is reduced and as a result the gas cone withdraws from the well (gravity segregation).

Frictional pressure drop follows the variations in fluid rates, and is largest when the well produces at its maximum gas rate (highest fluid velocities) as shown in Fig. 2. When the frictional pressure drop in the wellbore changes, so does the inflow distribution along the

[2] All sensitivities, cases 3–17, include frictional pressure drop calculations.
[3] Based on layers 2–24.
[4] Based on layers 1–36 (all layers).

Table 3: Summary of Simulation Results. (Absolute times and volumes are given only for case 2. For the other cases the differences relative to case 2 are shown. Frictional pressure drop is reported at max. gas rate.)

Case no.	Time to gas breakthrough (days)	Oil rate plateau (days)	Time to min. BHP (days)	Cum. oil production (10^6 Sm^3)	Frictional pressure drop (bars)
1	465	730	1299	4.6	2.0–1.8
2	+365	+146	+321	+0.1	0.0
3	+170	+117	+143	+0.1	1.2–1.1
4	+0	-206	-265	-0.1	3.9–3.4
5	-234	-240	-340	-0.2	4.0–3.5
6	+207	+132	+161	+0.1	1.1–1.0
7	+442	—	+425	+1.2	>2.3
8	+117	+43	-50	+0.1	2.3–2.1
9	+202	+117	-55	+0.3	2.6–2.3
10	+208	+79	-184	+0.3	2.9–2.6
11	+16	+0	-46	+0.0	2.2–1.9
12	-445	-669	-134	-3.1	3.5–1.7
13	—	—	-1299	-3.9	>0.7
14	-363	-588	-664	-2.6	4.0–3.3
15	-431	-679	-378	-3.4	3.5–2.4
16	-222	-310	-560	-1.5	3.5–3.1
17	+0	-103	+490	+0.2	1.3–1.0

well, and vice versa. The pressure profile in the wellbore and the inflow distribution are interdependent, and show a highly nonlinear variation over the well length, as illustrated by Figs. 3 and 4. For instance, the frictional pressure drop over the last half wellblock at the heel (25 m) may be of the same order of magnitude as the pressure drop over the whole upstream well length (almost 500 meters).

Inflow rate and pressure are assumed constant over the length of each grid block. The shape of the wellbore pressure profile therefore indicates that ideally, gridblock lengths should be much smaller close to the heel to get the most accurate inflow and pressure distribution in the well. In practice, use of many small gridblocks has to be avoided because of numerical problems and large CPU-times. The result is smoothed inflow and pressure profiles, which at the last few meters from the heel look more uniform than they should be.

Due to the 3-dimensional shape of the gas cone, relatively fine grid blocks should be used along the well length, and also past the heel and toe in the well direction. The pressure and saturation gradients can be large near the ends. Grid sensitivities have discovered that for this problem, it is not possible to simulate with as fine grid as needed and still achieve acceptable CPU-times. Most of the sensitivities are simulated using $25 \times 13 \times 36 = 11700$ grid blocks. A few are repeated with more blocks along the well ($30 \times 13 \times 36$). The simulator has large difficulties during the period of increasing gas rates following the break through, and most of the CPU-time is spent on this period.

Pipe roughness and friction factor are uncertain parameters. Even the high "effective roughness" used to account for non-homogeneous multiphase flow of free gas and liquid, does not seem to be very detrimental to the oil production behavior. Skin damage tends to hide wellbore roughness, giving slightly more uniform inflow along the well, which can be explained by the increased drawdown making frictional effects less important. A larger skin at the heel due to formation damage during drilling is reasonable, because of longer exposure time to drilling mud. This makes the inflow profile more uniform, but nonetheless the effect of wellbore friction dominates for this high permeability case. Lower permeabilities give earlier gas breakthrough due to a larger drawdown being necessary to obtain the specified rate. When permeability is reduced by a factor 10 (k_y in the range 200–2000 mD), the shape of the gas cone is less influenced by friction and free gas enters the well over most of the horizontal section. For very low permeabilities (k_y in the range 20–200 mD), the specified rates cannot be obtained, the well is controlled by bottomhole pressure all the time, and friction effects are not significant. The frictional pressure drop is very sensitive to the pipe diameter. In particular, it is detrimental to use a smaller pipe diameter than 0.152 meters (6 inches) in this case.

Based on these simulation results, it appears that frictional pressure drop in the wellbore only has a small influence on the cumulative oil produced. However, frictional pressure drop needs to be modeled properly to accurately predict the time to gas break through and how fast the gas rate will increase. Frictional pressure drop will dominate inflow to the wellbore when this pressure drop is significant compared to pressure draw down. For the more complex cases when conditions like permeability, distance to barriers, etc. varies along the well, the relative importance of wellbore friction may be different for each case. For high permeability reservoirs, like that studied here, wellbore friction cannot be neglected.

Coarse Grid and Well Transmissibility for Heterogeneous Reservoirs (Tasks 2,4)

The problem of scaling up reservoir heterogeneities is a crucial issue for a horizontal well. The productivity of a horizontal well is strongly affected by vertical variation of permeability, which can be extremely non-uniform. The main purpose of this new study (being conducted by Tomomi Yamada, a Ph.D. candidate under supervision of Prof. T. Hewett) is to find an appropriate method for computing coarse grid transmissibilities for a horizontal well.

Although a number of approaches are offered for up-scaling [1, 2, 5, 6, 7], none of them is sufficiently accurate in the vicinity of wells in extremely heterogeneous reservoirs. Vector permeability, K_{vector}, derived from Laplace solver [1] and tensor permeability, K_{tensor}, based on periodic boundary conditions [2] are examined on a example problem to scale-up a vertical section of a sand/shale sequence presented in Fig. 5. This heterogeneous reservoir model was generated using sequential indicator simulation technique [3]. In this model, permeability of shale is 1/1000 of sand and the volume ratio of shale is 0.434. The two methods resulted in an excess of 100% of error in well pressure required to achieve a fixed production rate for this example problem as indicated in Table 4. As Yamada and Hewett [4] pointed out, the major shortcoming is that the boundary conditions applied in these approaches are not appropriate for the kind of problem presented here.

it was expected that flow around a well may be controlled by the existence of inner boundary (well) and near-well heterogeneities. The influence of the outer boundary may disappear in the near-well region. If we can isolate the problem from the outer boundaries, the near-well region can be scaled-up without any need for considering the outer boundary conditions in the calculations. Then we just need to edit a few transmissibilities around the well to improve the accuracy of the coarse grid simulation. This is because most of

Table 4: Accuracy of Conventional Up-scaling in Well Pressure for the Example Problem

Method	Reference	P_{wf} (Coarse Grid)	Error
K_{vector}	Deutsch[1]	4113.65 psi	+153.2%
K_{tensor}	Durlofsky[2]	4219.21 psi	+123.1%

the total pressure drop occurs near the well. To investigate this hypothesis, we followed a method proposed by Gomez Hernandez [5]. In this approach, the region of interest is retrieved together with some extent of its surrounding area, called 'skin' in Ref. [5], and this is then used in the Laplace solver. A representative permeability is calculated from the pressure solution. However, our problem is different in that the domain has inner boundaries. We selected five 'sizes' of skin, with size 5 being almost no skin and size 0 being the entire reservoir as depicted in Fig. 6. Each size is feeded into a finite element simulator [6] which solves the single phase, steady-state, constant pressure outer boundary problem. The resulting transmissibilities are dependent on the size of skin. We attempted to find an appropriate size of the skin for which the transmissibilities are stabilized.

Scalar transmissibilites of twelve interfaces around the well, as shown in Fig. 7 is shown in Table 5 along with the size of skin for which they are obtained. It shows that some of these scalar transmissibilities are negative. The occurrence of negative coarse grid transmissibilities makes sense if we look into the detail of shale pattern within each coarse grid, however, they are usually unacceptable as input data for a coarse grid simulation. Next we computed tensor transmissibility for the four edges of the wellblock . This method was proposed by White [7]. We took the entire reservoir (size 0) and applied two boundary conditions, constant pressure and uniform flux, to pose the problem. White in Ref. [7] concluded that all the tensor transmissibilities have positive diagonal terms even if their scalar representation is negative. However, The results contained in Table 6 for our example problem shows negative diagonal terms.

Since negative transmissibilities cause computational problems while using iterative methods of solution, it is necessary to settle this issue before moving further in developing a new method. This issue is currently under investigation.

Table 5: Calculated Values of Scalar Transmissibilities [bbl/d/psi] for Different Sizes of Skin

Interface	Size 0	Size 1	Size 2	Size 3	Size 4	Size5
1	-0.3430	-0.6633	1.3717	10.0735	2.5945	1.1158
2	0.7530	0.7459	0.7416	0.7362	0.8247	0.7911
3	0.1374	0.1516	0.1616	0.1748	0.2019	0.3504
4	-0.0644	-0.0823	-0.1012	-0.1293	-0.1944	-0.1470
5	0.2871	0.2701	0.3210	0.3444	0.4861	0.8546
6	0.0793	0.0798	0.0787	0.0789	4.7588	2.0988
7	-1.1898	-1.2461	-1.4136	-1.9021	3.4076	0.8479
8	0.7044	0.7463	0.7925	0.8607	0.5191	0.5342
9	0.1083	0.0981	0.0871	0.0744	0.0471	0.0126
10	0.0057	0.0059	0.0060	0.0061	0.0052	0.0077
11	0.0911	0.0994	0.1071	0.1176	0.1731	0.1713
12	0.1642	0.1794	0.1941	0.2154	0.2473	0.5359

Table 6: Tensor Transimissibility [bbl/d/psi] of Well Block

Interface	Diagonal Terms	Off-Diagonal Terms
2	$T_{xx} = 0.6791$	$T_{xy} = 0.0225$
5	$T_{yy} = -0.4148$	$T_{yx} = 0.8634$
8	$T_{xx} = 1.9928$	$T_{xy} = 0.4824$
11	$T_{yy} = 0.0947$	$T_{yx} = -0.1097$

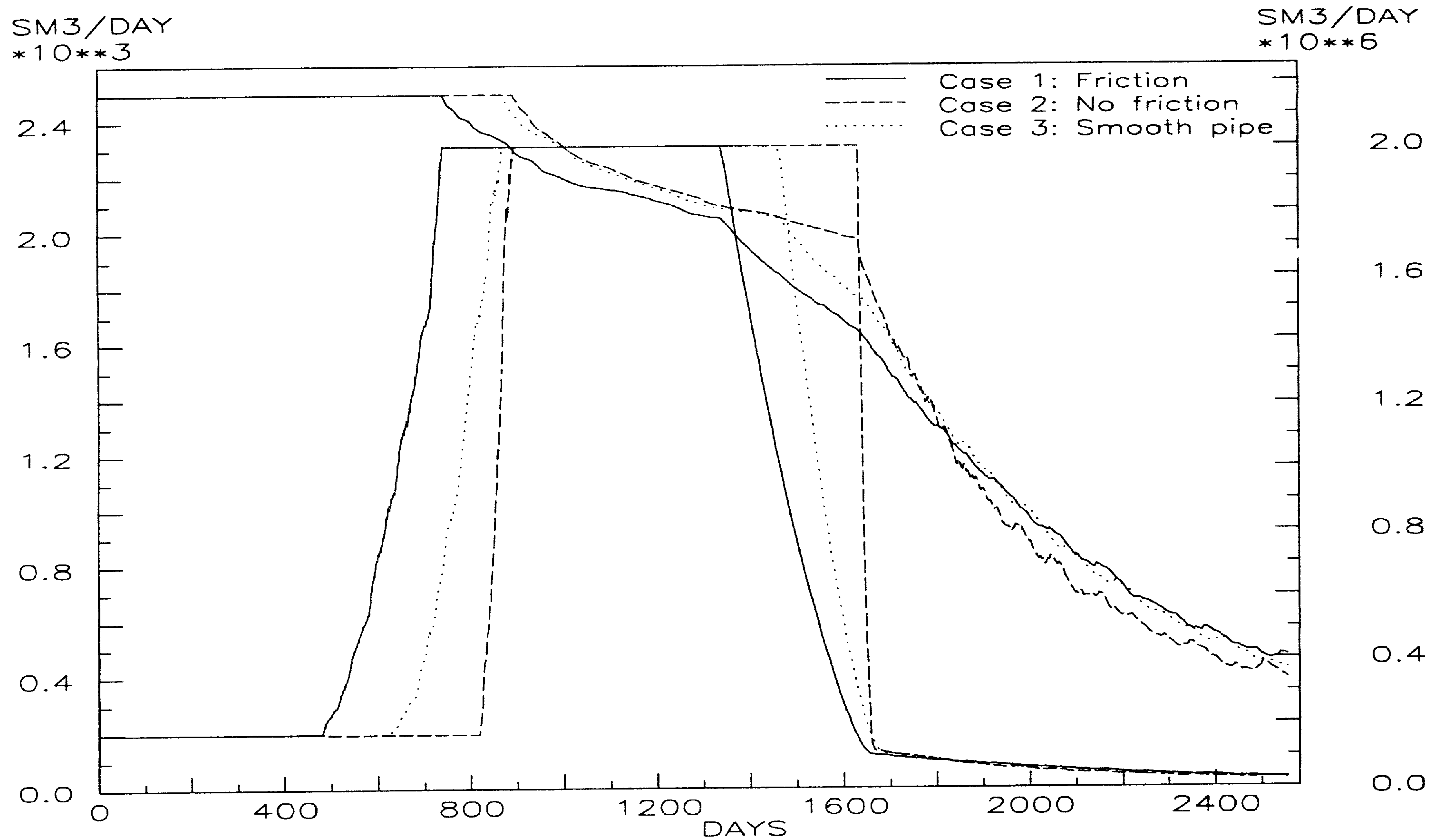

Figure 1– Oil and Gas Production Rates with Different Levels of Wellbore Friction

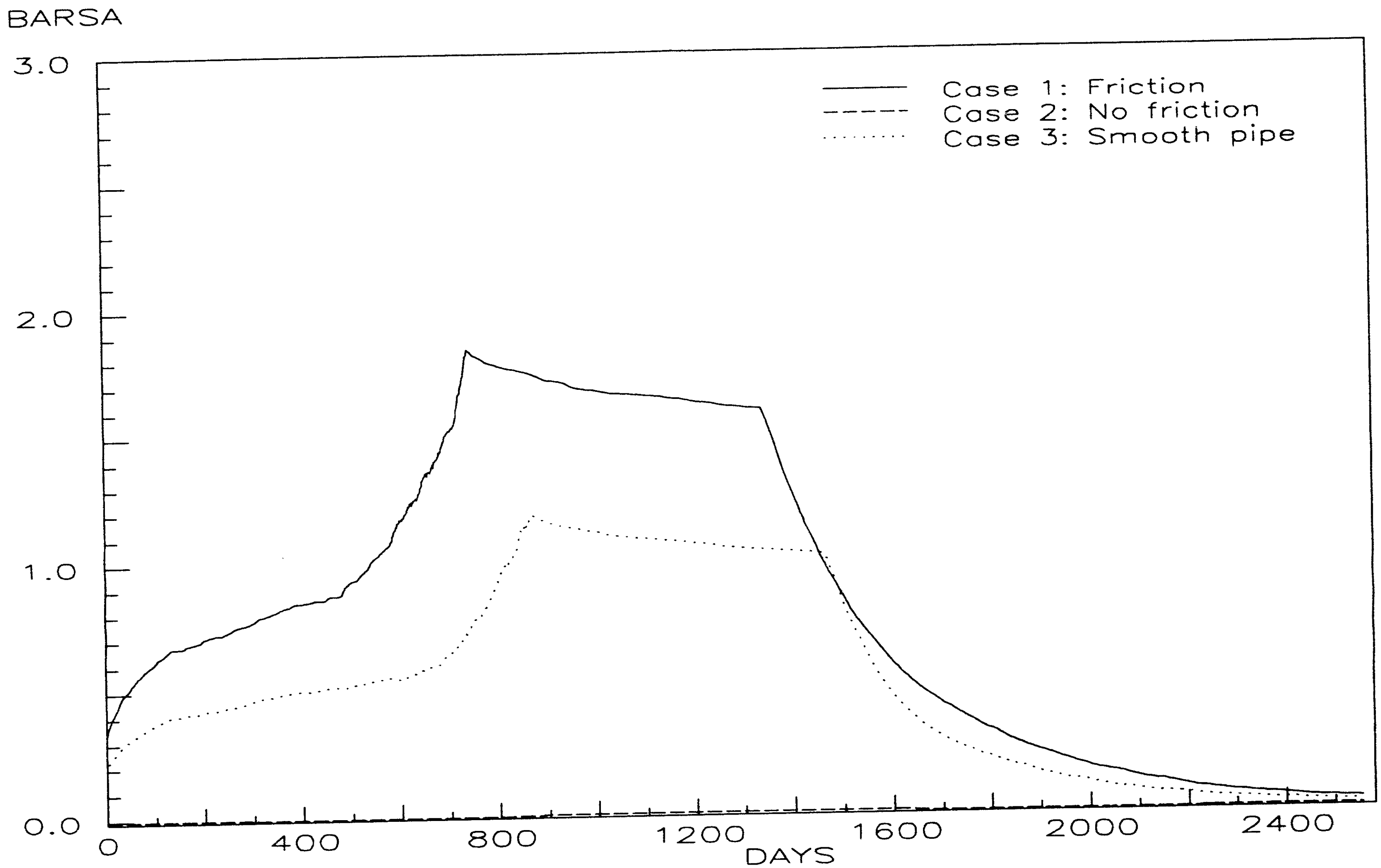

Figure 2– Frictional Pressure Drop in the Well. (Calculated as the Difference between Well Pressure at the Toe and Bottomhole Pressure.)

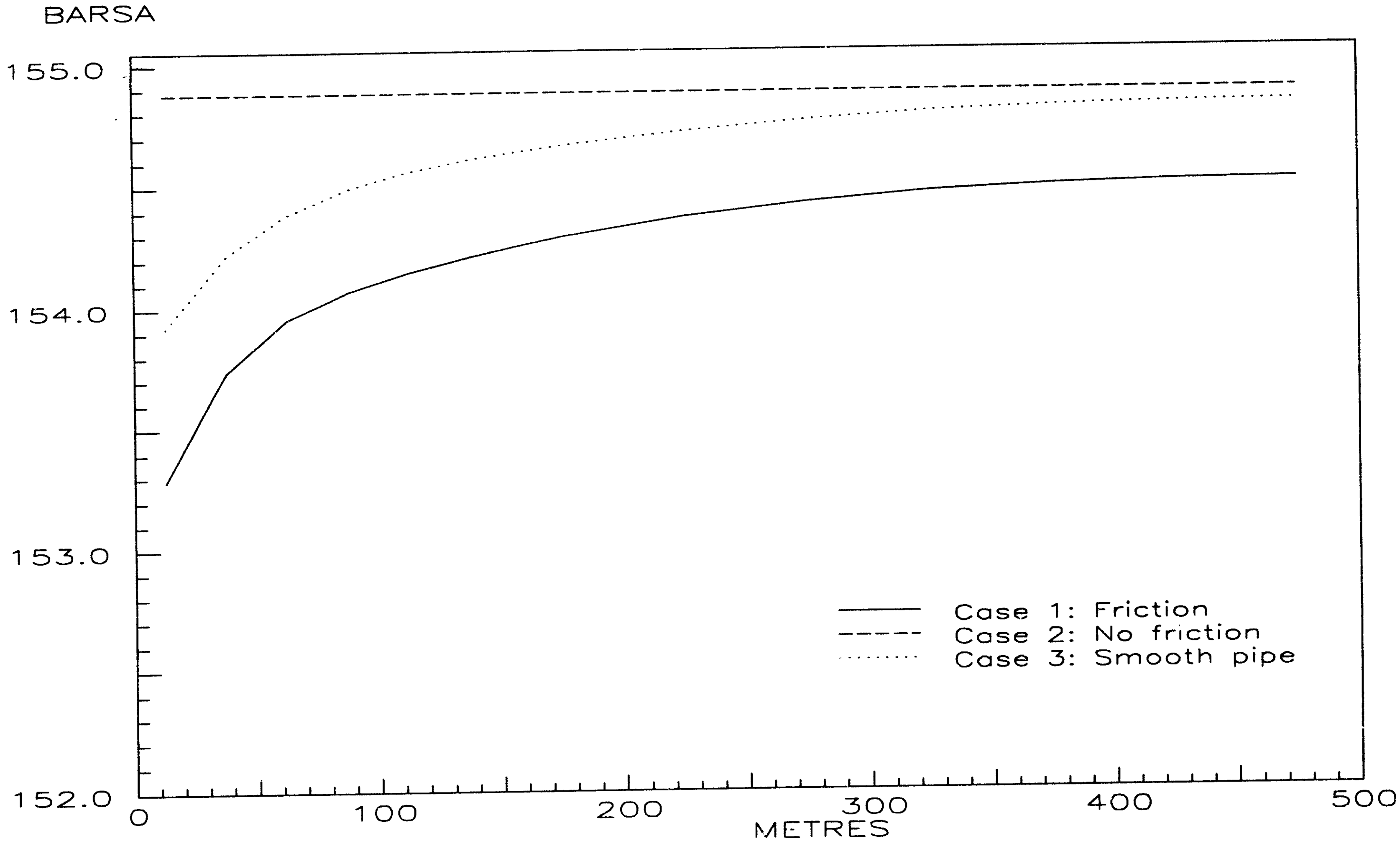

Figure 3– Pressure Profile in the Well, at 911 Days (2.5 Years) when Liquid and Gas Rates are High.

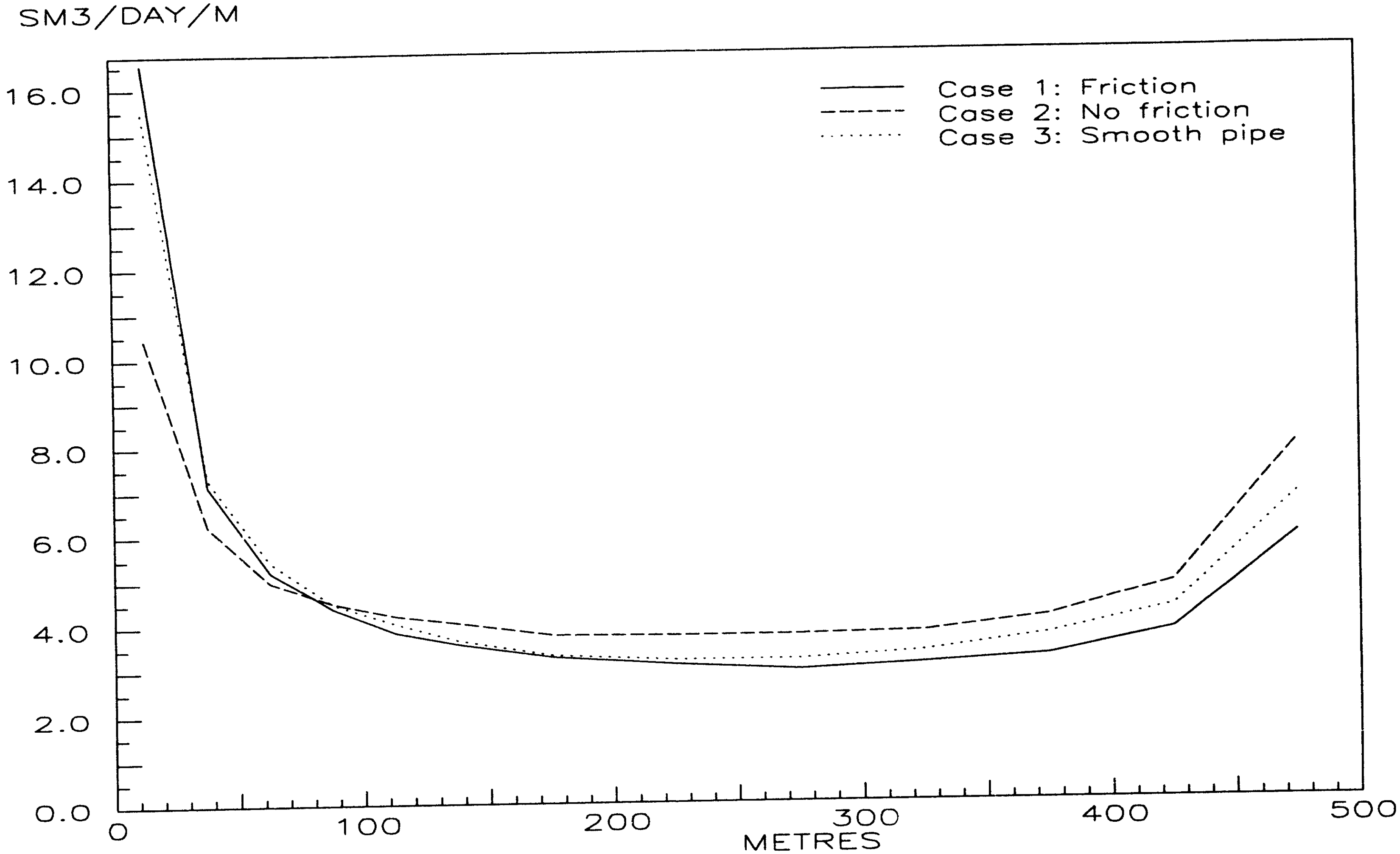

Figure 4– Inflow of Oil along the Well, at 911 Days (2.5 Years) when Liquid and Gas Rates are High.

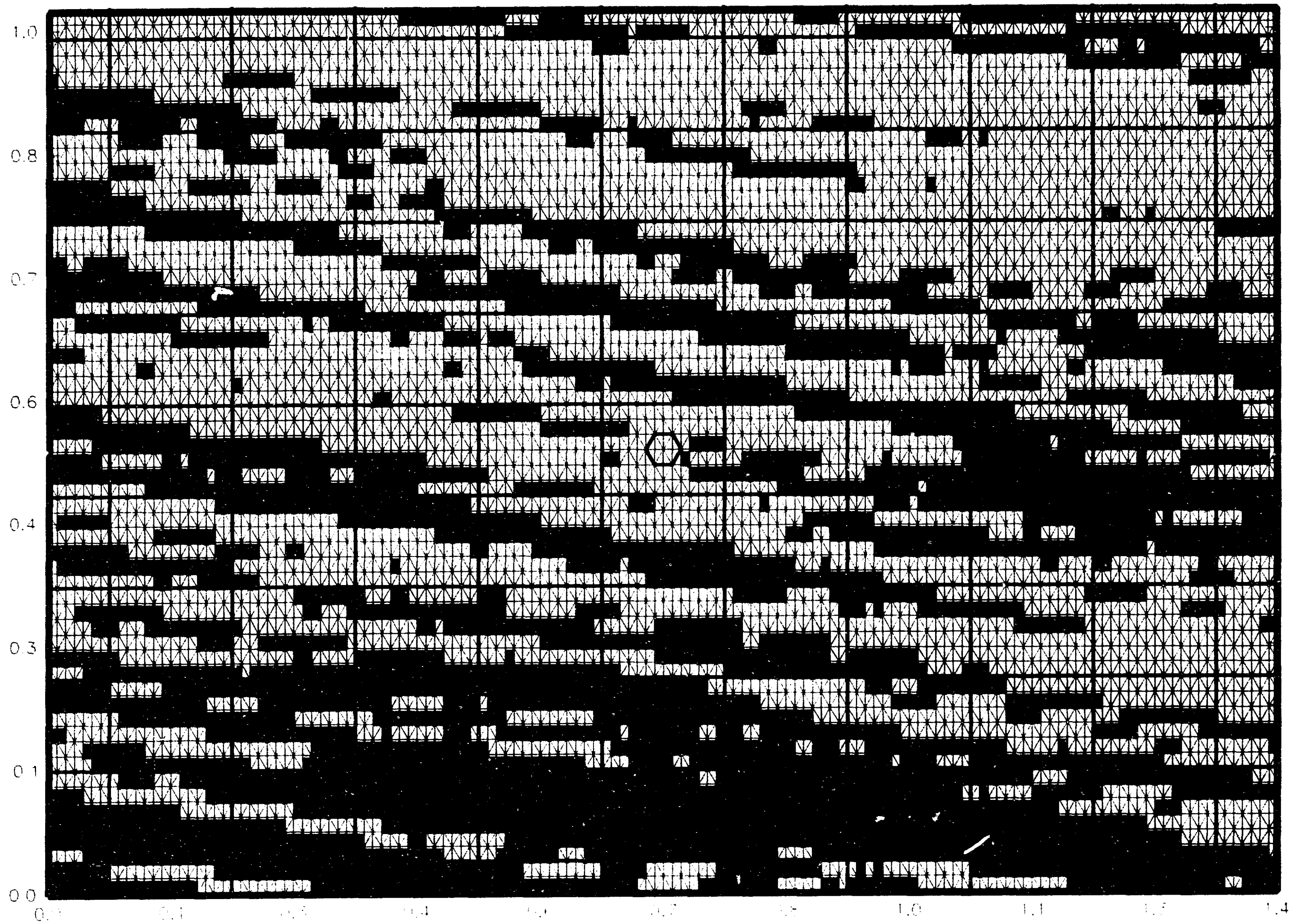

Figure 5- Sand/Shale Sequence for Scale-up

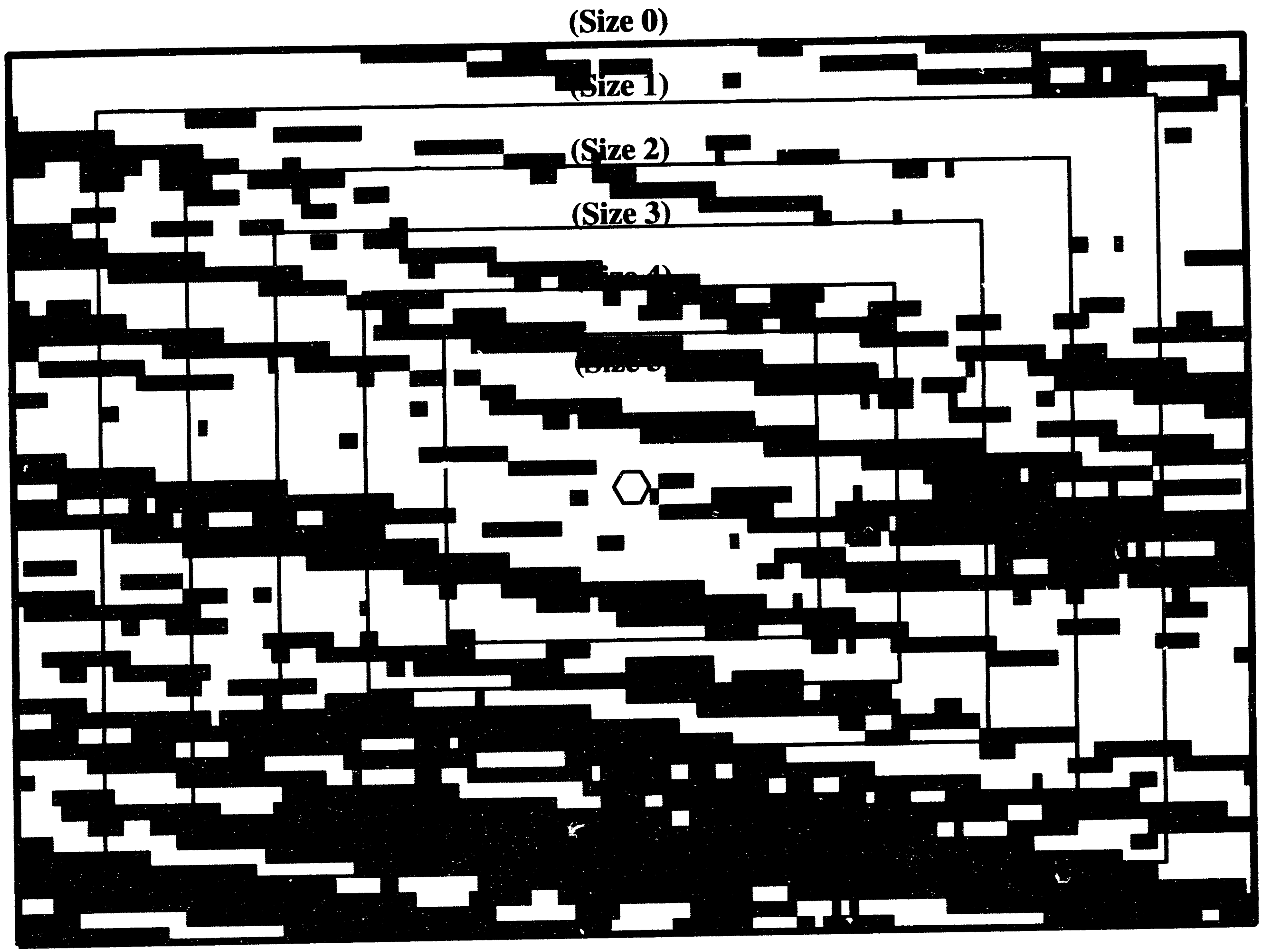

Figure 6- Skin Size for Transmissibility Calculation

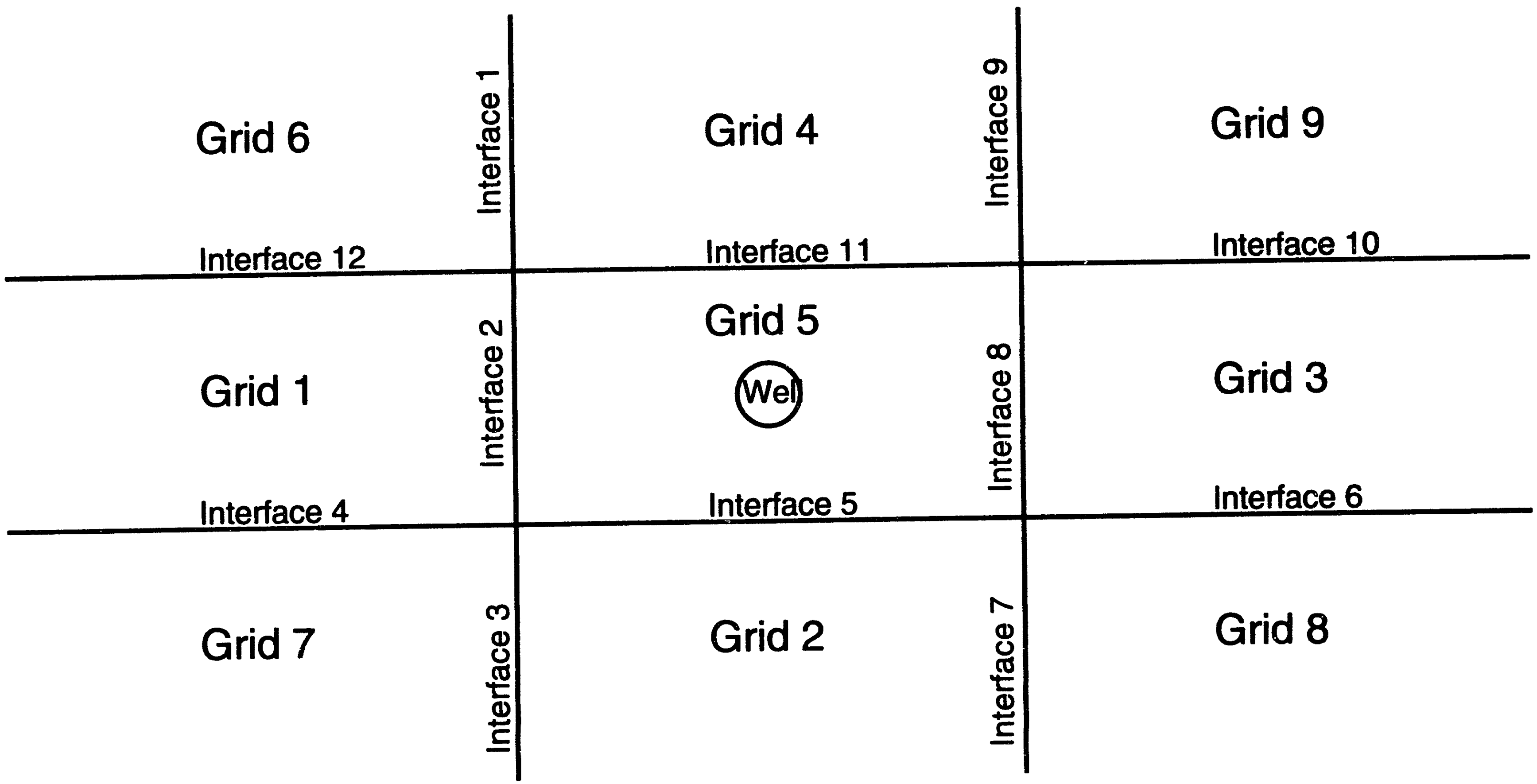

Figure 7- Block&Interface I.D.

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