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## Special Connection Fracture Model (SCFM) for Reservoir Simulation of Fractured Reservoirs

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*"a solution to reduce simulation time without disregarding the upscaling and dynamic representation of dual porosity flow models."*

### Introduction

The significant world oil and gas reserves related to naturally fractured carbonate reservoirs adds new frontiers to the development of upscaling and numerical simulation procedures for reducing simulation time. This work aims to accurately represent fractured reservoirs in reservoir simulators within a shorter simulation time when compared to dual porosity models, based on special connections between matrix and fracture mediums, both modeled in different grid domains of a single porosity flow model. For a detailed analysis of the benefits of applying special connections to a single porosity model to represent fractured reservoir in reservoir simulation we compare dynamic response from flow simulation and time consumption with the conventional procedure based on a dual porosity (DP).

### Methodology

The proposed methodology follows five main steps:

1) Define a conventional DP applied to fractured reservoirs, used as reference.
2) Define the special connection fractured model (SCFM) based on four stages: (a) construct a single porosity model with two symmetric structural grids, (b) geomodelling of fracture and matrix properties for the corresponding grid domain, (c) apply special connections through the conventional reservoir simulator to represent the fluid transfer between matrix and fracture medium, (d) calculate the correspondent fracture-matrix fluid-transfer, based on Warren and Root (1963) formulation.

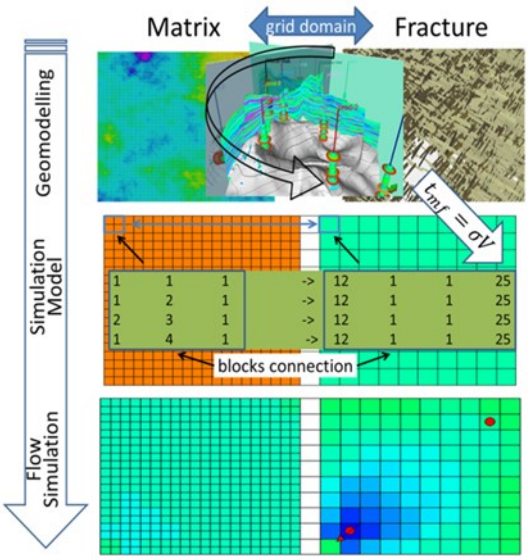


*Figure 1: Stages to define SCFM.*

3) Apply both procedures for a probabilistic framework considering static (geostatistical variables) and three dynamic scenarios based on rock wettability (water-wet, intermediate and oil-wet) to evaluate the proposed methodology against a different dynamic response.
4) Compare the dynamic response from flow simulation for both conventional DP and SCFM based on oil recovery, water cut and average reservoir pressure.
5) Compare the time consumption for the probabilistic framework considering geostatistical realizations and reservoir simulation.

### Application and Results

We based our study on Field B, a fractured reservoir type II, from the Campos Basin, Brazil. As the matrix permeability is generally small, we assume it as a constant of 0.1 mD. Furthermore, the matrix porosity is also assumed as a constant of 15%. DFN has an average length of 300 meters and an aperture of 6.0E-04 m. The average intensity (P32) is 0.08. These values are for the base case, before the introduction of uncertainties.

Figure 2 and shows the production strategy for the SCFM, respectively, using permeability as example for one geostatistical realization. To prevent an early water breakthrough, eight producers are completed on the reservoir top and five injectors on the base. For the DP, the matrix and fracture permeability are in the same domain, however, with the same grid block dimension for both systems.

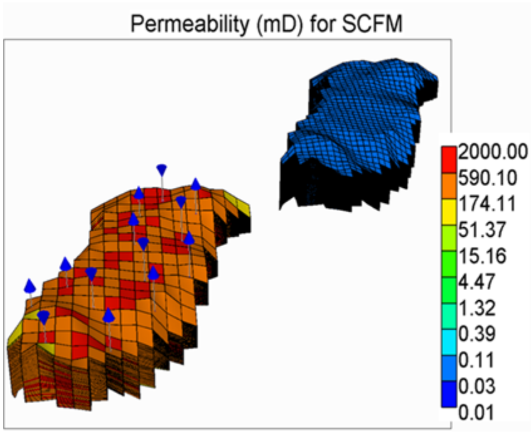


*Figure 2: Production strategy applied to SCFM for one geostatistical realization.*

For the DP, the grid block measures 100 x 100 x 2 meters. For the SCFM, the grid block measures 100 x 100 x 2 meters for the matrix domain and 200 x 200 x 4 meters for fracture domain. Given the small and continuous permeability values in the matrix, the geological grid resolution is the same as the simulation grid model. For the upscaling of DFN, we applied the Oda method.

We generated 20 realizations of petrophysical properties considering uncertainty in fracture variables (fracture aperture, fracture density and fracture length). These 20 realizations were combined with three types of rock wettability (oil-wet, water-wet and intermediate-wet). Therefore, it resulted in 60 simulation models for SCFM to be compared against 60 simulation models for DP.

Figure 3 shows the relative simulation time (ratio DP/SCFM) for all cases. Ratio below 1 means that SCFM has a higher simulation time than DP. Generally, the DP cases have a higher simulation time. Furthermore, for the geostatistical realization 14 the DP presents convergence issues for the three rock wettability scenarios. For water-wet scenarios the SCFM presents a close number of simulation models with higher or lower simulation time when compared to DP. This means that under imbibition forces, which are more expressive for water-wet rocks, SCFM did not present advantages regarding simulation time, with an exception of geostatistical realization 14, which presents numerical convergence issues for DP. For oil-wet and inter-

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mediate-wet scenarios, most DP cases require a higher simulation time for numerical convergence. While conventional reservoirs are often water-wet, fractured reservoirs are mostly intermediate to oil-wet (Chilingar et al, 1983). Therefore, SCFM presents a better computational response for the essential wettability scenarios in fractured reservoirs.

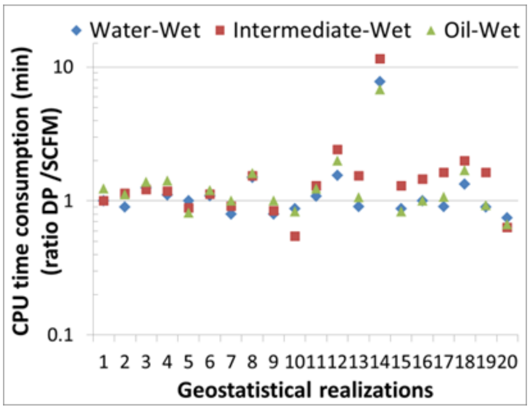


***Figure 3:*** *Simulation time (ratio Dual porosity / SCFM) for all simulation model according to rock-wettability.*

Table 1 shows the relative differences for water (WP) and oil cumulative production (OP) between DP and SCFM. The green values are the relative differences below 5%; yellow, between 5 and 10%; red, higher than 10%. The smaller relative difference means that DP and SCFM are quite similar for both objective functions. Note that only for two geostatistical realizations (14 and 20) the results extrapolate an acceptable match, considering the three rock-wettability scenarios. This means that geostatistical properties have a direct impact on this discrepancy. Combining these results with table 1, it is possible to observe that geostatistical realization 14 and 20 have the lowest average fracture permeability (<100mD), which is associated to the small values of fracture aperture in both realizations, close to 2 mm. Therefore, for lower fracture permeabilities (<100mD) SCFM did not reproduce the expected results. Nevertheless, for a type II fracture reservoir, it is not common for the average values to be below 100mD for fracture permeability data. Furthermore, realization 14 has presented convergence issues for DP and for the three rock wettability scenarios. According to Correia et al 2016, for oil-wet rocks the water saturation is more expressive in the fracture system but for water-wet rocks the matrix-fracture fluid transfer is more relevant for oil recovery due to the importance of imbibition forces. Therefore, the approach of special connections is more significant for water-wet scenarios. Nevertheless, SCFM presents the same response in reservoir simulation as the DP procedure, despite considering different kinetics in matrix-fracture fluid transfer.

**Conclusions**

This work proposed special connections to reduce simulation time in fractured reservoirs by modeling fractures and matrix properties into different grid domains through a single porosity model. The comparison between the conventional DP and SCFM showed that:

| | Water Wet | | Intermediate Wet | | Oil Wet | |
|---|---|---|---|---|---|---|
| | WP (%) | OP (%) | WP (%) | OP (%) | WP (%) | OP (%) |
| 1 | 0.73 | -3.05 | 0.25 | -1.97 | 0.16 | -1.65 |
| 2 | 0.59 | -2.28 | 0.25 | -1.56 | 0.10 | -1.02 |
| 3 | 0.24 | -2.23 | 0.25 | -3.11 | 0.15 | -2.42 |
| 4 | 1.28 | -5.40 | 0.56 | -4.42 | 0.39 | -3.83 |
| 5 | 0.51 | -3.87 | 0.33 | -3.93 | 0.23 | -3.58 |
| 6 | 0.67 | -2.71 | 0.19 | -1.50 | 0.12 | -1.21 |
| 7 | 0.60 | -2.65 | 0.21 | -1.72 | 0.15 | -1.60 |
| 8 | 0.63 | -3.67 | 0.40 | -3.76 | 0.25 | -3.02 |
| 9 | 0.57 | -2.97 | 0.23 | -2.17 | 0.16 | -1.86 |
| 10 | 0.69 | -3.53 | 0.28 | -2.80 | 0.21 | -2.71 |
| 11 | 0.17 | -1.78 | 0.20 | -2.73 | 0.11 | -2.08 |
| 12 | 0.60 | -3.46 | 0.39 | -3.60 | 0.24 | -2.82 |
| 13 | 0.23 | -1.72 | 0.20 | -2.27 | 0.12 | -1.84 |
| 14 | 9.45 | -37.07 | 2.91 | -26.10 | 2.25 | -22.91 |
| 15 | 0.49 | -3.10 | 0.28 | -3.04 | 0.19 | -2.75 |
| 16 | 0.55 | -2.87 | 0.24 | -2.25 | 0.16 | -1.93 |
| 17 | 0.13 | -1.49 | 0.19 | -2.74 | 0.11 | -2.11 |
| 18 | 0.60 | -3.98 | 0.39 | -4.07 | 0.25 | -3.35 |
| 19 | 0.26 | -2.01 | 0.20 | -2.44 | 0.12 | -2.10 |
| 20 | -29.62 | -9.21 | -19.24 | -5.63 | -16.63 | -5.30 |

<5% 5-10% >10%

***Table 1:*** *Relative difference (%) for water and oil cumulative production between DP and SCFM.*

1) SCFM has a considerable performance regarding a dynamic matching response with DP but within smaller simulation time.
2) SCFM has the same flexibility as DP to model discrete fracture networks and matrix properties, as both mediums are separated into two domains of a single porosity model;
3) SCFM did not present convergence issues considering all probabilistic realizations as for larger grid blocks the maximum changes in pressure and saturation are smoothed and, timestep cuts are reduced for each Newtonian iteration.

This work aims to contribute with a new method that can be applied in commercial flow simulators concerning fractured reservoirs and it presents itself as a solution to reduce simulation time without disregarding the upscaling and dynamic representation of dual porosity flow models.

**References**

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