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A Review of Coupled Dynamic Well-Reservoir Simulation ⋆

D. V. A. da Silva* J. D. Jansen*

* *Delft University of Technology, Stevinweg 1, 2628 CN Delft, The Netherlands (e-mail: d.v.a.dasilva@tudelft.nl).*

Abstract:
The numerical simulation of the dynamic interaction between hydrocarbon reservoirs and wells has been an object of study for over three decades. Such a coupled approach is necessary to solve a variety of dynamic flow problems, such as pressure transient analysis (well testing) with wellbore storage, liquid loading, near-well reservoir clean-up, unstable gas lift, or the development of smart well control systems. We review various examples of coupling dynamic reservoir and well models as described in the open literature.

Keywords: Wellbore/Reservoir, Coupling, Interaction, Multiphase, Dynamic, Modeling, Simulation, Smart, Control

1. INTRODUCTION

We consider the numerical simulation of multi-phase fluid flow (oil, gas and water) from a *reservoir* (a deep subsurface layer of porous and permeable rock surrounded by impermable layers) through *wells* (fluid flow conduits) to surface. Most of the available commercial dynamic wellbore flow simulators assume a constant flow rate for the inflow of reservoir fluids into the well for a given *bottom hole pressure (BHP)* (the pressure at the bottom of the well) and reservoir pressure. Also, most commercial dynamic reservoir simulators use steady-state values for the BHP as a function of given oil, gas and water flow rates and *tubing head pressure (THP)* (the pressure at the top of the well). The justification for these conventional approaches lies in the strong separation in time scales between well bore and reservoir response: most reservoir processes (pressure and temperature propagation and pore fluid saturation changes) typically respond to disturbances on a timescale from hours to decades, whereas wellbore processes (pressure and temperature propagation and multi-phase fluid flow) typically have response times in the order of seconds to tens of minutes.

However, a variety of studies has demonstrated that there are situations where there is an overlap in response time scales, often in a limited near-well region in the reservoir, such that a coupled simulation approach is necessary. Fig. 1, taken from Nennie et al. (2007), gives an overview of different well and reservoir processes and their corresponding time and spatial scales of interest.

Wellbore storage is the effect that after shutting-in a producing well by closing a valve at the top of the well, a certain amount of afterflow occurs from the reservoir into the well. This influences the pressure build-up in the well, which is of importance for *pressure transient analysis (PTA)*, also known as *well testing* or *build-up testing*, in which averaged reservoir parameters are estimated from the reservoir pressure step-response (measured with a downhole pressure gauge) after closing-in the well. Similar *reservoir transients* may occur as a result of other disturbances in the well bore flow. The overlapping regions for well bore storage (green) and reservoir transients (dark blue) in Fig. 1 indicate that coupled simulation will be required to accurately represent PTA with wellbore storage effects.

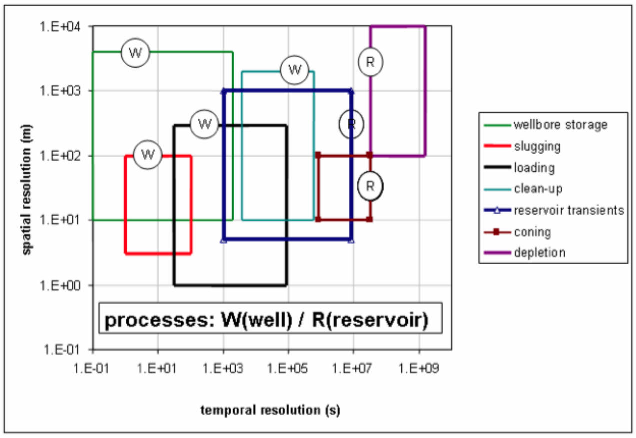

Fig. 1. Time and spatial scales for well (W) and reservoir (R) processes (Nennie et al., 2007). Overlapping W-R regions indicate the need for coupled well-reservoir simulation.

Several other reservoir and well processes have been indicated in Fig. 1, which may or may not result in overlapping areas. *Slugging* is a periodic fluctuation in pressures and flowrates in wells carrying a mixture of gas and liquids. It is a form of self-excited oscillation usually caused by accumulation of liquids in the near-horizontal parts of wells or *flow lines* (pipelines connecting the top of a well to

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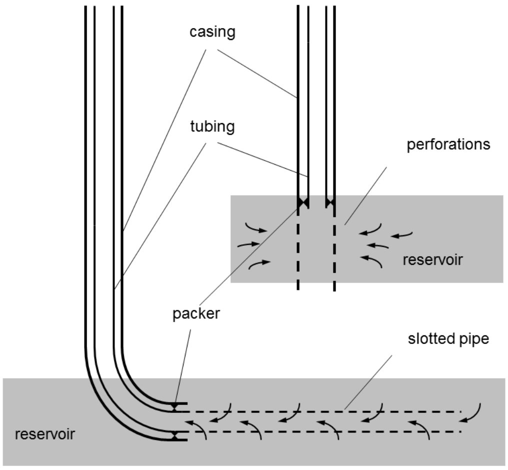

Fig. 2. Schematic of a horizontal well (left) and a vertical well (right) producing from two separate reservoirs.

the production facilities). Similar oscillations may occur in vertical wells, a phenomenon known as *heading*, if there is storage capacity in the form of an annular space between the *tubing* (the inner tube in a well carying the gas and liquid) and the *casing* (the outer tube, isolating the well from the surrounding rock) see Fig. 2. In modern wells such an interaction is normally prevented with the aid of a *packer*, which seals the annular space. However similar heading phenomena may occur in case of *gas lift*, a process where gas, pumped into the annular space at surface, enters the tubing at the bottom of the well through a dedicated gas-lift valve, with the aim to reduce the hydrostatic head in the well and thus increase the oil production. Although not indicated in Fig. 1, well-reservoir interactions may be of importance in unstable gas-lift production; see, e.g., Belfroid et al. (2005).

Liquid *loading* often occurs in gas wells at the end of their producing life, when the gas velocity is insufficient to lift the co-produced water to surface, resulting in an accumulation of water at the bottom of the well. *Clean-up* is the process of producing a well just after completion with the aim to remove liquids (e.g. *drilling mud*) that have invaded the near-well reservoir during the well construction process. Water *coning* is a reservoir flow process in which a well that drains an oil layer floating on top of a water layer starts to produce high amounts of water because the water, which is typically less viscous than the oil, flows more easily towards the well than the oil. A similar gas coning process may occur when a well drains an oil layer covered by a *gas cap*. The last reservoir process indicated in Fig. 1, *depletion* is simply the drainage of the reservoir by expansion of rock and fluids resulting in a gradually deceasing reservoir pressure. It is a typical example of a reservoir process that proceeds too slow to justify coupled well-reservoir simulation.

2. WELLBORE FLOW SIMULATION

The numerical simulation of well bore flow is based on the classic set of conservation equations in fluid dynamics: i.e. those for mass, momentum and energy, leading to a system of coupled nonlinear partial differential equations (PDEs). Nearly always the simulations are one-dimensional, using averaged properties over the pipe area, and typical state variables are *pressure*, *enthalpy*, and *mass flow rates* for water and two hydrocarbon *pseudo components*. The pseudo components are usually taken as the oil and gas *phases* at standard conditions, and represent lumped hydrocarbon components (methane, ethane, propane etc.). They form the two constituents of the oil and gas phases which are functions of pressure and temperature. The most simple hydrocarbon model, the *black oil model*, assumes that gas can dissolve in oil, but not vice versa, i.e. the gas phase contains only the gas pseudo-component, whereas the liquid phase contains both oil and gas pseudo components. The *volatile oil model* is a slightly more complex model in which both pseudo components can be present in both phases. Finally, a fully *compositional* model can be used in which the mass flow rate of each individual hydrocarbon component is tracked. Such a compositional analysis is unusual for wellbore flow simulation, unlike what is customary in chemical engineering. However, currently there are groups in the petroleum community working towards the development of compositional well modeling (**?**).

Two-phase flow of gas and liquid (in which the oil-water mixture is effectively treated as a single phase), or three-phase flow of gas, oil and water, can be simulated at various levels of sophistication. The earliest models used a single mixture equation based on empirical correlations, disregarding the *slip* (i.e. the difference in velocities) between the phases. More complex models also use a mixture equation, but account for slip with the aid of (semi-) empirical equations to describe the *hold-up* of liquid caused by the lower liquid velocity, compared to the gas velocity, in typical production wells. The hold-up is usually taken to be *flow-regime* dependent, while the occurrence of a particular flow regime, e.g. bubble flow, slug flow, annular flow or mist flow, is determined as function of (superficial) gas and liquid velocities, fluid properties, pipe diameter, pipe inclination, etc. A special case of mixture equations are *drift flux* equations which do take into account the slip between gas and liquid but typically do not explicitly model separate flow regimes; see Fig. 3. More complex models consider *segregated flow* in which the individual phases are modeled with separate conservation equations, requiring expressions for the interaction between the phases. The most sophisticated models are fully *mechanistic* and attempt to describe the interaction between the phases in detail, e.g. at the level of individual liquid slugs or bubbles, starting from first principles. However, all wellbore flow models contain, to varying degrees, empirical parameters to account for unmodelled physics.

In some strongly simplified cases it is possible to describe transient or steady-state well bore flow with the aid of analytical expressions. However, in general the governing PDEs are solved numerically. In most cases the simulations are steady-state, in which case the PDEs degenerate to ordinary differential equations (ODEs) which can be numerically integrated along the spatial coordinate (the well bore axis). The most simple simulators use an equidistant explicit finite difference discretization, but more sophisticated simulators use higher order integration methods (e.g. Runge Kutta methods) with adaptive step size control. A few well bore simulators can perform dynamic

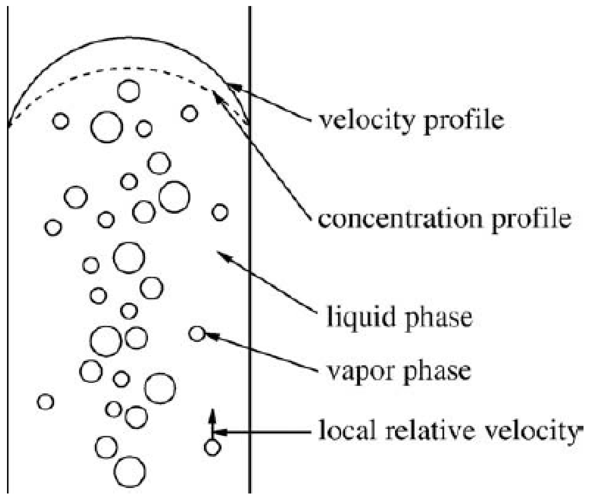

Fig. 3. Schematic depiction of the drift-flux model illustrating slip between phases caused by density differences and a concentration of gas bubbles in the center of the well where the velocities are highest (Livescu et al., 2009b).

simulations, in which case the PDEs are typically solved with an implicitly integrated finite difference (or finite volume) scheme with upwinding. Special care needs to be taken to simulate the phase appearance/disappearance that occurs when passing the gas-liquid interface in the well. Moreover, a special treatment may be required in the area of the well where reservoir influx occurs, and where acceleration in axial direction of laterally entering flow, or three-dimensional flow configurations may need to be taken into account.

For further information on well bore flow simulation, see, e.g., the textbooks of Brill and Mukherjee (1999), Hasan and Kabir (2002) and Shoham (2006).

3. RESERVOIR SIMULATION

The numerical simulation of reservoir flow is typically based on a modified set of conservation equations. In particular the classic conservation-of-momentum equation is replaced by a semi-empirical quasi-steady-state relationship known as *Darcy's law* justified by the very slow movement of fluids through the pores. Moreover, most reservoir simulators consider iso-thermal conditions, in which case the conservation-of-energy equation becomes superfluous. Typical state variables are pressure, enthalpy (in case of thermal simulation), and either the (pseudo-) component accumulations, or the phase *saturations* (the dimensionless fractions of the pore space filled with oil, gas or water). Just like in well bore flow, the hydrocarbons are described with black or volatile oil models or, occasionally, fully compositional.

The essential nonlinearity in reservoir simulation stems from the fact that the presence of a phase influences the flow of the other phases in a non-trivial manner. The underlying mechanisms involve (fluid-fluid) interfacial tensions and (solid-fluid) capillary effects which are taken care of by macroscopic semi-empirical relationships. The resulting systems of PDEs typically contain a parabolic (near-elliptic) pressure equation and one or more parabolic (near-hyperbolic) saturation equations. The equations are usually semi-discretised in space with the aid of the finite volume method, although sometimes (mixed) finite element discretizations are used. The number of grid cells is usually in the order of 10^4 to 10^6, and the resulting systems of ODE's are therefore typically very large.

The temporal discretization is usually performed either fully implicitly, with a simple backward Euler scheme and full Newton-Raphson iteration at each time step, or sequentially, with an implicit treatment of the pressure equation and an explicit treatment of the saturations (IMPES). Most simulators use an adaptive time stepping scheme that reduces the step size if the Newton-Raphson procedure does not converge within a predefined number of iterations, and increases the step size when the procedure converges quickly. The values of permeability (inverse resistance to flow) in the grid cells may vary with several orders of magnitude from cell to cell, which results in numerically poorly conditioned systems of equations requiring specialized linear solvers. Moreover, the poorly known reservoir geology often results in the need to work with ensembles of reservoir models to span the underlying uncertainty.

For further information on reservoir flow simulation, see, e.g., the textbooks of Aziz and Settari (1979), Chen et al. (2006) and Chen (2007). For a description in systems and control notation see Jansen (2013).

4. COUPLED DYNAMIC SIMULATION OF WELL AND RESERVOIR FLOW

Coupling dynamic simulators for well and reservoir flow implies the coupling of two underlying sets of PDEs. In the most rigorous approach the two sets are merged into a single set, which is then discretized in space and time using appropriate numerical methods. However, such a *fully implicit* or *monolithic* approach (in which the reservoir and wellbore equations are solved simultaneously starting from a single system of differential equations) is usually impractical, because it would require rewriting major parts of the underlying simulators. Moreover, it is usually unnecessary, and it has been shown to be very well possible to couple the simulators in a somewhat more loose fashion. In that case it is necessary to define synchronization points, i.e. moments in time at which information from the well bore simulator is passed to the reservoir simulator and vice-versa. This can be most easily achieved by forcing the time steps to coincide at predefined problem-specific synchronization times (in the simplest case equi-distantly). The interaction of information can then be performed in an *implicit* or *explicit* fashion.

In the explicit case the reservoir simulator computes the phase flow rates entering the well at a given synchronizaton time step n for a given BHP at the previous synchronizaton time step $n-1$. The well bore simulator computes a new BHP at time step n, for a given THP and the phase rates obtained from the reservoir simulator starting from time step n again. This new BHP is then used as input for the reservoir simulator up to the next synchronization time step $n+1$, etc. (Note: several variations on this procedure exist). In the implicit approach, the phase rates and bottom hole pressures at each synchronization time step n

are computed alternatingly with the two simulators, until convergence. Note that convergence is not guaranteed.

The implicit coupling approach described above is an example of simple iteration, a.k.a. Picard iteration. For all iterative schemes the time step sizes and/or the synchronization times may be chosen as either fixed or variable. In the latter case, some form of adaptative scheme may be used, driven by the performance of the iteration process at each synchronization step. In a more sophisticated approach the residuals, i.e. the differences between the BHPs and/or the phase rates (possibly scaled to ensure similar orders of magnitude) as computed by both simulators, could be driven to zero by Newton-Raphson iteration. This would require the computation of derivatives of the residuals with respect to the controlled variables (the BHPs and/or rates) which could either be done using numerical differentiation (with finite differences), or using an adjoint technique.

5. LITERATURE REVIEW

In this section we review various examples of coupling dynamic reservoir and well models as described in the open literature. We do not claim completeness, but we believe to have covered a representative set of publications. For an overview of further work we refer to a recent paper by Bahonar et al. (2011). Also, Table A.1 gives an overview of the most relevant numerical aspects of the individual simulators and the coupling as far as they could be retrieved from the cited publications.

The earliest studies on the dynamic interactions between wells and reservoirs, in the 1980s, were mainly focused on well testing. Authors like Miller (1980), Winterfeld (1989), Almehaideb et al. (1989) and Stone et al. (1989) all developed their own mathematical and numerical models and simulators.

Miller (1980) studied the early-time fluid-flow interactions between reservoir and wellbore, and also the effects of temperature changes during well testing of geothermal wells.

Winterfeld (1989) simulated a pressure-buildup test in a vertical well. He used a single-phase example to illustrate wellbore storage and wellbore fluid inertia effects after shut-in, and a two-phase example to show phase redistribution effects. The author also compared the simulated data with field cases. The underlying models and the discretization schemes of the coupled model were carefully described.

Almehaideb et al. (1989) investigated the effect of phase segregation in the wellbore during gas and water injection. Through that, they showed that the effect of wellbore gravity segregation can't be ignored when properly simulating a multiphase injection process.

Stone et al. (1989) published an article with similar characteristics as the previous two, but targeted mainly at horizontal wells. The authors gave a complete description of the models, including special treatment of the momentum equations of the wellbore, and cleary stated all the closure equations and the discretization technique. Moreover, the mathematical model was compared with a scaled experiment and the stability of the model was discussed.

It was only in the late 1990s that the interest shifted to *smart wells*, i.e. wells equipped with downhole *Inflow Control Valves (ICVs)* allowing for the individual control of fluid influx from different reservoir segments. Another form of well control prompting coupled simulation studies involved automatic control of *wellhead chokes* at the top of the well, primarily aimed at the reduction of gas coning. The study of ICVs and automatic control of wellbores is becoming more important with the development of computer processing capacity and well technology. With the increasing number of production wellbores and the application of production optimization of reservoirs, well control has gained much attention.

Holmes et al. (1998) studied *multi-lateral* wells (i.e. wells with multiple branches in the reservoir) implemented in a reservoir simulator with the aid of a *multi-segment* well model. They describe two case studies which assess the performance of the model and examine the effects of flow control devices in two types of wells. The first case study compares the operation of two types of downhole control in a horizontal well; the second one examines the behavior of a bi-lateral well and shows how branch-to-branch *crossflow* (i.e. flow from one reservoir layer into another) can be controlled to maximize the total oil production. This was also one of the first studies that used a *drift-flux* model to represent the flow in the wellbore, instead of the often used separated-fluid models. An advantage of the drift-flux model is that it takes into account slip between the gas and liquid phases but uses mixture equations for the momentum transport, which reduces the computational requirements compared to segregated flow models. Moreover, the absence of separate flow-regimes in the drift-flux model results in a gradual change of flow rates with pressure drop, as opposed to models that use discrete flow regime transitions which often lead to discontinuous derivatives in flow rates or even discontinuities in the rates themselves. Such discontinuities could hamper the iterative solution of the coupled reservoir-wellbore equations. After the appearance of this publication, several researchers started to implement drift-flux models in their coupled dynamic wellbore-reservoir models, see, e.g., Stone et al. (2001), Pourafshary (2007), Livescu et al. (2009b) and Semenova et al. (2010).

In the early 2000s, Sturm et al. (2004) studied dynamic reservoir well interactions in smart wells, pointing out the main dynamic phenomena involved in smart well control. They built their own well and reservoir models to simulate a variety of dynamic well-reservoir interactions such as the response to a ramped increase of the *drawdown* (i.e. the difference between reservoir and bottom hole pressure), the response to sinusoidal variations of the drawdown, and well behavior during heading instability. They also compared their simulations with field data and demonstrated that, on a timescale of minutes, the dynamics of the near-well reservoir significantly affect the *inflow performance relationship (IPR)* (i.e. the flow rate as a function of drawdown) of the well.

Sources of well performance instabilities caused by water or gas *breakthrough* (i.e. the sudden start of water or gas co-production after an initial period of pure oil production) were studied by Belfroid et al. (2005). The interaction between reservoir, well and surface facilities can result in an unstable system, in which pressures and flow rates display large fluctuations.

After the studies of Sturm et al. (2004), other specific studies were carried out to prove the necessity of a coupled approach. Several other phenomena were described by, e.g., Sagen et al. (2007) and Nennie et al. (2007), in which the interaction between reservoir, well and pipeline is relevant: severe slugging, slow liquid build-up in the wellbore during shut-in, packing of pipelines and wells following a shut-in, the start-up of the production, pigging operations, and gas and water coning. In these studies, the coupling was performed by using existing commercial software. The dynamic multiphase well simulator OLGA and the dynamic reservoir simulator MoReS were coupled explicitly to study a test case of a horizontal well with three inflow sections located in a *thin oil rim* (i.e. a relatively thin layer of oil in-between water and gas). The authors compared their results with those obtained by performing the simulations without coupling.

Leemhuis et al. (2008) worked on gas coning in horizontal wells, implementing a PID feedback controller, and introduced a strategy to find the optimal production set point and the benefits of downhole control using an ICV. Furthermore, they compared a coupled steady-state well/dynamic reservoir model to a fully dynamic coupled model.

Twerda et al. (2011) performed a techno-economic analysis of control strategies, investigating the usage of *Inflow Control Devices (ICDs)* (passive restrictions, typically used to selectively limit the influx of reservoir fluids along the bottom part of a horizontal well), and made a comparison with other production procedures in a gas coning situation.

Bahonar et al. (2011) provide a good review of several studies applying wellbore-reservoir simulators. The authors aim to validate a numerical single-phase gas flow model against analytical models, showing the benefits of the numerical approach.

Recently Iemcholvilert (2013) published a thesis addressing the dynamic couplig of not only the reservoir and the wells, but also the surface facilities. The author treats various ways to couple the systems of equations of the surface and subsurface models, using explicit, implicit and fully-implicit coupling.

6. CONCLUSION

Based on this literature review we conclude that:

- Over the past decades there have been an increasing number of publications on dynamic coupled reservoir-wellbore flow.
- The initial applications were restricted to the effects of wellbore storage during well testing.
- The advent of automatic well control, such as surface-based coning control or downhole inflow control, has increased the necessity of dynamic wellbore-reservoir interaction modeling and simulation;
- The use of drift-flux models for wellbore fluid flow has increased significantly, due to their higher accuracy compared to homogeneous models and simplicity compared to separated fluid models. Moreover, they do not suffer from discontinuities because of flow-regime transitions which is beneficial for the numerical convergence of coupled well-reservoir simulations.

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Appendix A

Table A.1. Overview of the most relevant numerical aspects of the individual simulators and the coupling

Authors	**Reservoir Simulator**	**Wellbore Simulator**	**Coupling**
Stone et al. (1989)	M, T, B, I, S	M, T, B, H, SF	F
Almehaideb et al. (1989)	M, N, B, I, S	M, N, B, V, SF	F
Winterfeld (1989)	M, N, B, I, S	M, N, B, V	F
Holmes et al. (1998)	M, ?, B, I, S	M, ?, B, G, DF	F
Stone et al. (2001)	M, T, C, I, S	M, T, C, G, DF	I
Sturm et al. (2004)	M, N, B, ?, S	M, N, B, V, DF	?
Belfroid et al. (2005)	S, N, B, ?, S	M, N, B, V, DF	?
Bhat et al. (2005)	M, N, B, I, S	M, T, B, ?, ?	I
Pourafshary (2007)	M, T, C, I, S	M, T, C, V, DF	F
Sagen et al. (2007)	M, T, C, I, S	M, T, C, G, ?	F
Nennie et al. (2007)	M, T, C, E, G	M, T, C, G, SF	E
Leemhuis et al. (2008)	M, T, C, E, G	M, T, C, G, SF	E
Livescu et al. (2009a)	M, T, B, I, S	M, T, B, G, DF	F
Semenova et al. (2010)	M, T, C, I, S	M, T, C, G, DF	F
Twerda et al. (2011)	M, T, C, E, G	M, T, C, G, SF	E
Bahonar et al. (2011)	S, T, C, I, G	S, T, C, ?, -	F

Legend:

- **Reservoir Simulator** - M = multi-phase, S = single-phase, T = thermal, N = non-thermal, B = black oil, V = volatile oil, C = compositional, I = implicit, E = Implicit Pressure Explicit Saturation, S = sequential, G = general reservoir shape, S = simple reservoir shape, ? unknown.
- **Wellbore Simulator** - M = multi-phase, S = single-phase, T = thermal, N = non-thermal, B = black oil, V = volatile oil, C = compositional, G = general well, V = vertical well, H = horizontal well, SF = separeted flow, DF = Drift-Flux, ? unknown.
- **Coupling** - E = explicit, I = implicit, F = fully-implicit, ? unknown.
- Note: Most papers focus on the spatial discretization but give little or no information about the temporal discretization and the choice of the synchronization times for the coupling.

