UNIVERSIDADE ESTADUAL DE CAMPINAS
FACULDADE DE ENGENHARIA MECÂNICA
E INSTITUTO DE GEOCIÊNCIAS

KÍLDARE GEORGE RAMOS GURJÃO

OSCILLATION MITIGATION IN SUBSURFACE AND SURFACE COUPLINGS USING PID CONTROLLERS

REDUÇÃO DA OSCILAÇÃO EM ACOPLAMENTOS ENTRE SISTEMAS DE SUBSUPERFÍCIE E SUPERFÍCIE UTILIZANDO CONTROLADORES PID

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Orientador: Prof. Dr. Denis José Schiozer

Coorientador: Prof. Dr. Eduardo Gildin

Este exemplar corresponde à versão final da Dissertação defendida pelo aluno Kíldare George Ramos Gurjão e orientado pelo Prof. Dr. Denis José Schiozer.

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A ata dessa defesa com as respectivas assinaturas dos membros encontra-se no processo de vida acadêmica do aluno.

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DEDICATION

This work is dedicated to:

Jesus Christ who gave his own life to save the humanity and from whom all my faith and force to never give up and always achieve great goals comes from.

My parents, Sr. José Gurjão Netto and Sra. Robéria Nascimento Ramos Gurjão, who have raised me showing the fundamental importance of a life full of Jesus Christ, honesty and education.

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“For with God nothing shall be impossible.”

Luke 1: 37 (KJ Bible)

RESUMO

A simulação acoplando reservatórios e sistemas de produção é um problema desafiador e pode se tornar uma tarefa difícil caso modelos intensivos computacionalmente com múltiplos reservatórios e sistemas de produção complexos sejam considerados. Todavia, simulações aplicando a técnica de acoplamento podem promover melhor precisão na previsão de produção, especialmente em planos de desenvolvimento de longo prazo. A integração dos sistemas petrolíferos pode ser realizada por duas metodologias principais: utilizando diferentes simuladores (acoplamento explícito) ou considerando todos componentes individuais do sistema em um único programa (acoplamento implícito). O método explícito é mais flexível, permitindo a integração entre simuladores comerciais preparados para cada aplicação. Como desvantagem, soluções oscilatórias podem ser geradas. Neste trabalho, uma nova metodologia para redução das instabilidades numéricas (oscilações) decorrentes do acoplamento explícito é formulada por meio de uma configuração de controle. Resultados deste trabalho mostram que o acoplamento explícito sem um mecanismo para evitar instabilidades numéricas apresenta oscilações que podem crescer ao longo da simulação. A razão desse efeito é atribuída a curva IPR (*Inflow Performance Relationship*) e consequentemente a vazão do ponto de operação (q_{OP}) permutados no início do passo de tempo entre simulador de reservatórios e programa acoplador, os quais podem não ser representativos para todo intervalo de acoplamento. A fim de reduzir as oscilações numéricas, é implementado um tipo de sistema de controle por *feedback*, conhecido como controlador PID (Proporcional, Integral e Derivativo). O controlador PID, com parâmetros (K_C, τ_I, τ_D) sintonizados manualmente para um grupo de configurações de poços, ajusta a curva IPR tradicional gerada pelo simulador de reservatórios, de forma que o erro entre a pressão de fundo de poço calculada pelo simulador de reservatórios (BHP_{RS}) e a pressão de fundo de poço definida pelo ponto de operação (BHP_{OP}) seja mínimo. Dessa forma, é obtido um valor de q_{OP} representativo para o intervalo de acoplamento. A nova metodologia foi testada em um modelo numérico sintético (UNISIM-I-D) baseado no campo de Namorado (Bacia de Campos – Brasil), composto por 20 poços satélites (7 injetores e 13 produtores). O controle PID reduz oscilações nas variáveis vazão e pressão no estudo de caso e, além disso, os resultados convergem com o caso base que representa o sistema de produção dos poços produtores por meio de tabelas apropriadas de perda de carga.

Palavras Chave: Acoplamento Explícito; Curva IPR; Oscilação; Controlador PID.

ABSTRACT

Simulation coupling subsurface (reservoir) and surface (network) systems is a challenging problem and can become a daunting task if computationally intensive multi-reservoir models and complex surface network facilities are considered. Nevertheless, simulations applying the coupling technique can bring greater accuracy in production forecast, especially in long-term field development plans. Integration of petroleum systems can be done by two principal methodologies: using different simulators (explicit coupling) or considering all individual components of the system in one simulator (implicit coupling). The explicit method is more flexible, allowing the integration of commercial-off-the-shelf simulators. However, as a drawback, it can yield oscillatory solutions. In this work, a new framework for mitigating explicit coupling numerical instabilities (oscillations) is developed by recasting the problem in a control setting. Results from this work show that explicit coupling without a mechanism to avoid numerical instabilities presents oscillations that can grow throughout the simulation. The reason for such effect is attributed to the IPR (Inflow Performance Relationship) curve and consequently the operating point flow rate (q_{OP}) exchanged at the beginning of each time step between the reservoir simulator and the coupling program, which may not be representative for the entire coupling interval. In order to mitigate the numerical oscillations, one type of feedback control system, namely a PID (Proportional, Integral and Derivative) controller is applied. The PID controller, with parameters (K_C, τ_I, τ_D) tuned manually for a group of well settings, adjusts the traditional IPR curve generated by the reservoir simulator so that the error between the bottom-hole pressure calculated by the reservoir simulator (BHP_{RS}) and the bottom-hole pressure defined in the operating point (BHP_{OP}) is minimal. In this case, a q_{OP} value representative for the entire coupling interval is obtained. The new methodology was tested in a synthetic numerical model (UNISIM-I-D) based on Namorado field (Campos Basin – Brazil), comprised by 20 satellite wells (7 injectors and 13 producers). The PID control reduces the rate and pressure oscillations in the case study, and results converge with base case scenario, which represents the network system of producer wells by proper pressure drop tables.

Key Word: Explicit Coupling; IPR Curve; Oscillation; PID Controller.

LIST OF FIGURES

LIST OF TABLES

NOMENCLATURE

Latin Letters

B	Formation volume factor
BHP	Bottom-hole pressure
C	Compressibility
e_k	Error at time k
e_{k-1}	Error at time k-1
e_{k-2}	Error at time k-2
e(t)	Error at time t
E_i (x)	Exponential integral function
GLR	Gas/liquid ratio
H	Reservoir thickness
II	Injectivity Index
IPR	Inflow Performance Relationship
K	Absolute permeability
K_C	Proportional gain
K_r	Relative permeability
OPR	Outflow Performance Relationship
P	Pressure
$\bar{p}$	Drainage pressure
p_B	Bubble point pressure
p_{Block}	Well block pressure
P_c	Capillary pressure
p_e	Outer pressure of well drainage area
p_i	Initial reservoir pressure
p_{Stable}	Pressure estimated using new methodology based on PID controllers
p_{wf}	Well flowing pressure
PI	Productivity Index
Q	Flow rate
$q_{injection}$	Injection flow rate
$q_{production}$	Production flow rate
R	Radius
r_e	Outer radius of well drainage area
R_S	Solution gas oil ratio
r_w	Wellbore radius
S	Skin factor
S	Saturation
SP	Controller set point
T	Time
T	Temperature
T_C	Critical temperature

TPR	Tubing Performance Relationship
u_{Bias}	Particular constant that in open loop keeps y(t) at design level
$u(t_k)$	Total controller output at time k
$u(t_{k-1})$	Total controller output at time k-1
y(t)	Controller measured variable
WCUT	Water cut
WHP	Well-head pressure

Greek Letters

Γ	Euler's constant
Δp_f	Frictional pressure drop
Δp_{Ke}	Pressure drop due to kinetic energy change
Δp_{Pe}	Pressure drop due to potential energy
Δp_S	Pressure drop due to pipe fittings
Δp_{total}	Total pressure drop
Δp_W	Pressure drop due to external machine
Δt	Time step
$\Delta u(t_k)$	Instantaneous controller output at time k
μ	Viscosity
τ_D	Derivative time constant [time]
τ_I	Integral time constant [time]
Φ	Porosity

Subscripts

G	Gas
L	Liquid
O	Oil
og	Oil-gas
OP	Operating point
ow	Oil-water
RS	Reservoir simulator
T	Total
W	Water

TABLE OF CONTENTS

1 INTRODUCTION

Reservoir simulation plays a paramount role in the decision making process of reservoir engineering. It is related to the fact that forecast of fluid flow in porous media promotes the development of high efficient exploitation projects aiming at suitable reservoir management.

Therefore, reservoir models carrying great amount of technical and economic data are updated and optimized in a cyclic process over the life time of reservoir, completed at the moment of field abandonment. This activity is well represented by the Closed Loop Reservoir Management and Development in Figure 1.1, which is divided in three principal stages: model construction (green), assimilation of real production data for history matching (red) and selection of production strategy under uncertainty (blue).

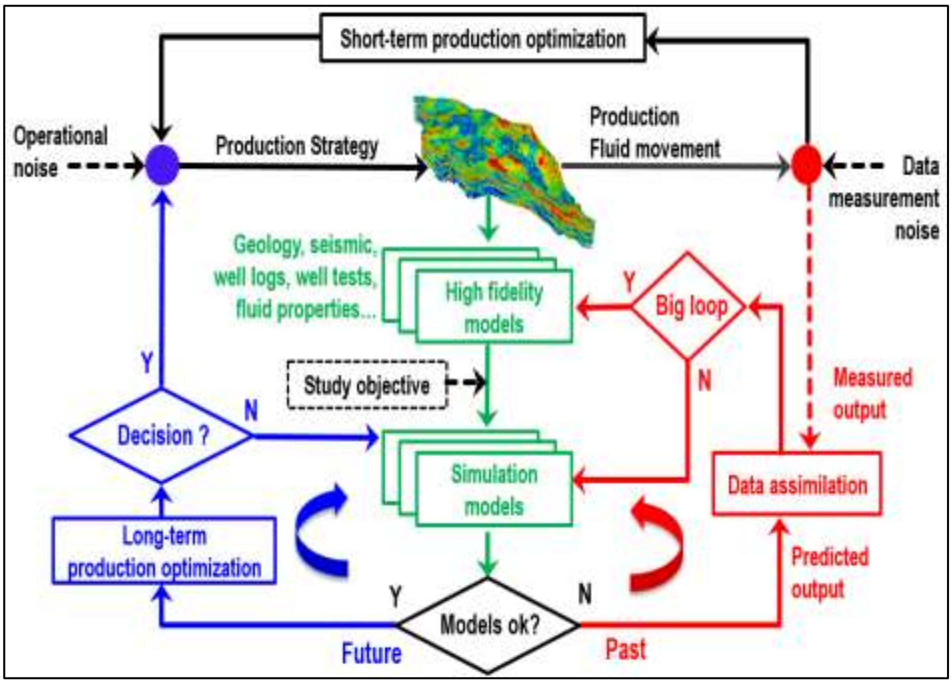

Figure 1.1 Closed Loop Reservoir Management and Development (modified from Schiozer et al., 2015).

High production along with low costs is a requirement in every oil and gas project, especially in scenarios of low oil prices attached to high demand. In order to accomplish this exigence, sophisticated and complex production facilities are being implemented in a representative number of fields worldwide, for instance: Pre-Salt, Gulf of Mexico and North

Sea. Therefore, the necessity of exploitation strategies integrating subsurface and surface systems is rising extensively.

Petroleum systems can involve multiple reservoirs connected to platforms with operation restrictions, subsea separation units, manifolds, intelligent wells and other complexities. The realism of numerical computations linking the complete petroleum system depends on the type of integration mechanism implemented.

The simplest way that network system can be incorporated in the simulation is by well boundary conditions in standalone models. However, depending on the case study, the process to calculate representative well constraints is not easy and the obtained values are not precise because surface systems have many unique characteristics that may not be suitable represented in a simplified way, for instance, informing a constant well bottom-hole pressure or flow rate.

In order to bring higher confidence to the project, reservoir and production systems should be integrated applying specific and accurate techniques.

Simulation integrating subsurface and surface systems, known as Integrated Asset Modelling (IAM) or Integrated Production Modelling (IPM) (Figure 1.2), are important in field development/optimization studies (Ghorayeb et al., 2005) as it can lead to better reservoir prediction performance assessments and potentially higher production and financial outcomes. Proper subsurface/surface integration brings greater accuracy in predicting reservoir deliverability as it captures the complex interactions between reservoirs, wells, pipelines and surface/process facilities (Figure 1.3). The realism of such computations depends heavily on the type of integration mechanism implemented.

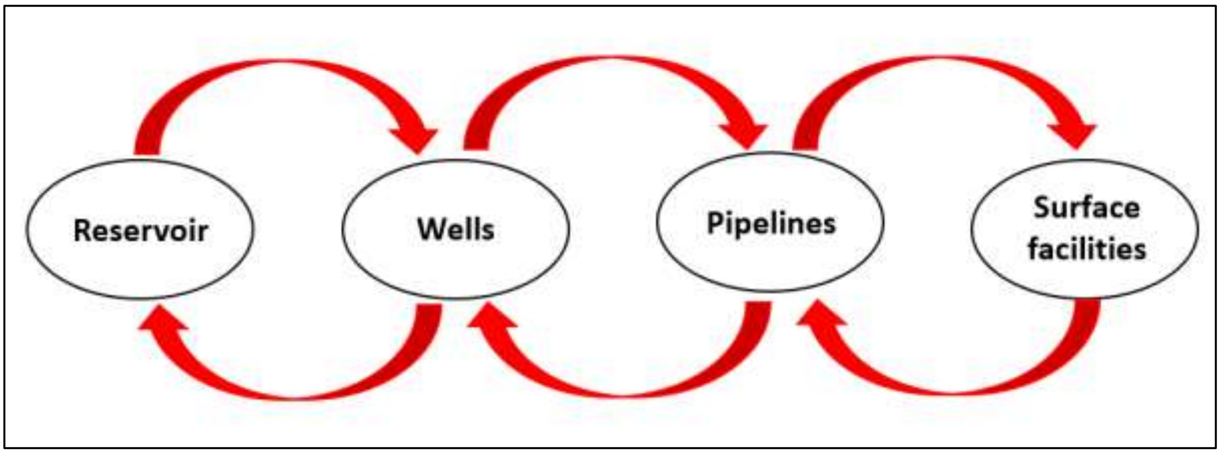

Figure 1.2: Components of a typical offshore petroleum system.

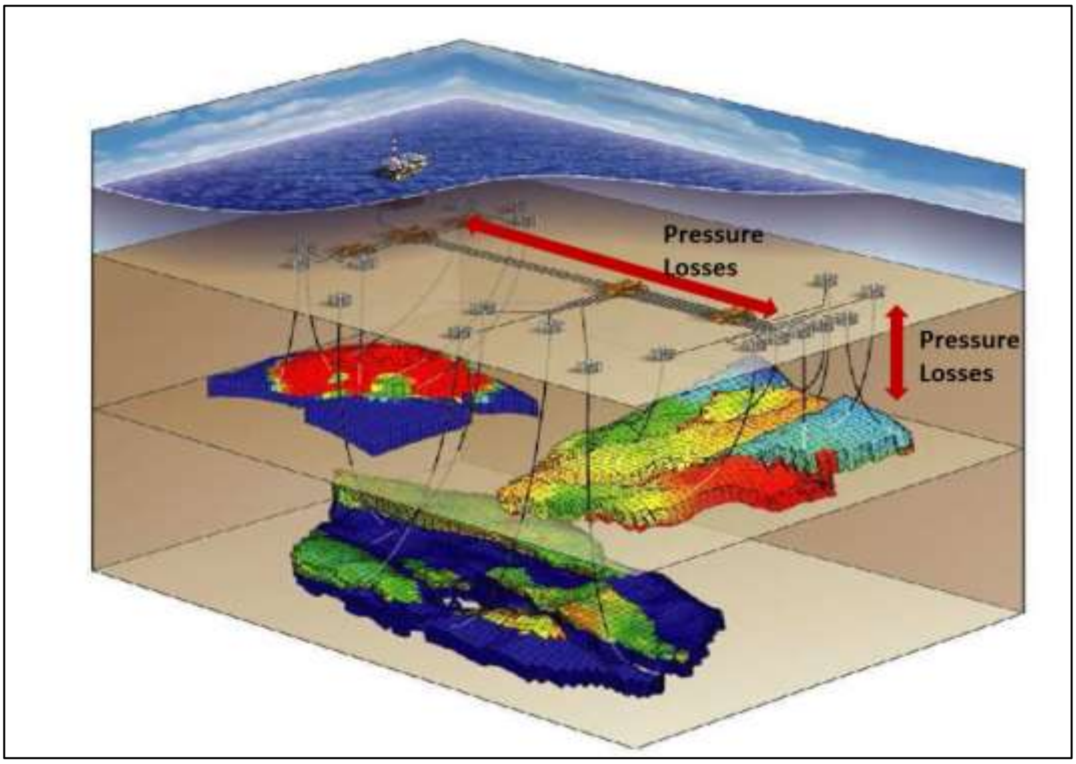

Figure 1.3: Example of offshore petroleum system (Redick, 2017).

The nomenclature of IAM techniques varies in the literature. In this work, it is adopted the nomenclature as defined by Hohendorff Filho & Schiozer (2016):

1) Decoupled method: pre-calculated tabulated data or data files containing multiphase flow information representing the required pressure to produce or inject (Outflow Performance Relationship – OPR curve), are introduced in the reservoir simulator in order to represent the network system (Bento, 2010).

2) Explicit coupling: multiple simulators are combined to simulate the fluid flow in each system of the field (Hiebert et al., 2011; Hohendorff Filho & Schiozer, 2014), and the exchange of data between them (balancing) is automated; it happens through the use of standard interfaces or simple methods for file sharing from a common repository (Hiebert et al., 2011).

3) Implicit coupling: a single simulator is used to perform the entire simulation (subsurface-surface), therefore the solution of all governing equations is calculated within the same framework (Hiebert et al., 2011).

Table 1.1 presents concisely how previous introduced techniques attempt to integrate network and reservoir systems.

Table 1.1: Description of mechanisms applied by different methodologies to integrate subsurface-surface systems.

Technique	Mechanism
Standalone model	Pre-stablished well boundary conditions
Decoupled method	Pre-calculated pressure drop files for different production scenarios
Explicit coupling	Multiple simulators solve the systems separately
Implicit coupling	Single simulator solves all systems simultaneously

The application of implicit coupling may avoid instabilities associated with pressure reconciliation between network and reservoir systems. However, it may not be the best procedure in several situations due to problem formulation complexity, which involves two systems with different physical characteristics in just one simulator. Thus, it can trigger for instance excessive computational time.

According to Victorino et al. (2016), the advantages of explicit coupling are related to well management alternatives and freedom to select reservoir/production systems software. However, as a drawback of the method, instabilities in the results can occur during the process, which can be mainly attributed to the non-continuous balancing between simulators (Cao et al., 2015).

Explicit coupling between surface and subsurface systems requires data exchange between reservoir simulator and coupling program, which can be accomplished by the passage of the Inflow Performance Relationship (IPR) curve from reservoir simulator to the coupling program and well operating point (fixed constraint) from coupling program to reservoir simulator. This process takes place at the beginning of each time step (Figure 1.4), thus the IPR curve and the fixed constraint sometimes may not be representative for the entire coupling interval, causing error and oscillation in the results throughout the simulation.

The reservoir simulator traditionally calculates the IPR curve based on Peaceman equation (Peaceman, 1978), which is dependent on well block pressure (P_{Block}).

During consecutive time steps, drainage pressure ($\bar{P}$) is generally less prone to great variations than P_{Block}, because the first represents an area average value while the second a grid block value in the well completion zone. Several techniques were proposed to reduce the explicit coupling oscillation problem, calculating an stable IPR curve based on $\bar{P}$. In this case, some authors have defined different methods to determine $\bar{P}$: subdomain simulation

(Guyaguler et al., 2010), simulation of simultaneous flow tests (Liang et al., 2013), and analytical scaling combined with fast marching method (Zhang et al., 2017).

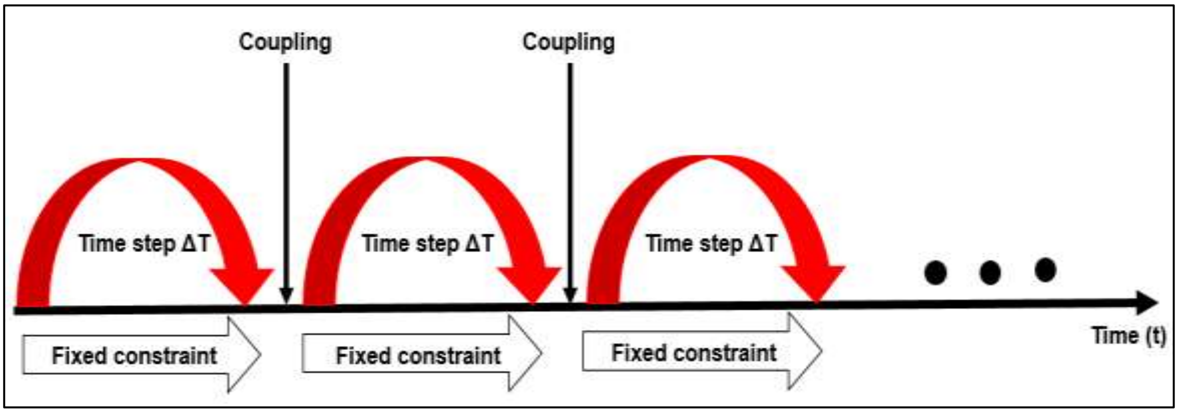

Figure 1.4: Scheme showing time domain with discrete points where simulators exchange data in explicit coupling process.

Other techniques proposed to reduce the subsurface-surface coupling instabilities includes:

- Correction of traditional IPR curve generated by reservoir simulator applying an equation correlating P_{Block} and flow rate (Hohendorff Filho & Schiozer, 2016); and
- Determination of optimum time step size using adaptive time stepping technique, assisted by the PID (i.e., proportional, integral and derivative) controller algorithm proposed by Gustafsson et al. (1988) (Redick, 2017).

In this project, the benefits of explicit coupling are evaluated through a case study involving network and reservoir systems of UNISIM-I-D benchmark, which is a synthetic numerical model based on Namorado field- Brazil (Avansi & Schiozer, 2015). It is shown that the explicit coupling of subsurface and surface systems present non-physical oscillations. As pointed before, many fixes have been proposed to mitigate this problem. Here, a different approach is taken based on recasting the whole coupling in a control framework, applying the concept of PID control to minimize the instabilities.

PID controller is a control loop feedback mechanism (automatic control) widely used in engineering problems, which has the purpose to stabilize a system by bringing its error, defined as the difference between desired set point and measured variable, to zero. According to National Instruments (2011), the popularity of this type of controller can be attributed to its robust performance and function simplicity, which allows engineers to operate them in a simple and straightforward manner.

According to Dorf & Bishop (2017), automatic control continually measures process operating parameters such as temperatures, pressures, levels, flow rates, speeds, positions and concentrations, and then makes decisions to, for example, open valves, slow down pumps and turn up heaters so that the selected process measurements are maintained at desired values.

The PID controller algorithm applied to minimize the explicit coupling oscillation problem of UNISIM-I-D benchmark has parameters (K_C, τ_I, τ_D) tuned manually for a group of well settings. Results indicate that the new technique work properly and efficiently in the case study, minimizing the instabilities of flow rate and pressure.

1.1 Motivation

The industry is constantly searching for novel and reliable approaches that can be supported by solid mathematical, physical and scientific foundations, and yet can be readily applicable to many projects. Hence, unstable solutions commonly observed in explicit surface and subsurface couplings – a recurrent problem in the oil and gas industry – is an important topic that deserves special attention in the academic environment.

Therefore, this work was dedicated to figure out an innovative method to minimize the oscillation problems present in the explicit coupling of reservoir and production systems.

PID controllers were selected to compose the new methodology because of two factors: first, its main purpose is to stabilize systems preventing oscillation, and second, it holds important characteristics as robust performance, function simplicity and popularity.

The advantage of the new technique formulated based on control engineering, compared to other methodologies that aim to reduce the explicit coupling instabilities is the fact that it avoids significant computational cost and access to reservoir simulator internal code.

1.2 Objectives

This work has the following three objectives:

1) Develop a methodology for oscillation mitigation using PID controllers, whereby a correction to the traditional IPR curve generated by numerical reservoir simulator is developed, in order to determine a more representative operating point for the entire coupling time step, attempting to minimize the explicit coupling instabilities;

2) Evaluate the performance of formulated methodology by a comparison of its results with base case that, in this work, is the decoupled method with reliable responses (this is possible because a simple production system is considered in the case study);
3) Perform a sensitivity analysis study with PID parameters (K_C, τ_I, τ_D), intending to define the effects of each constant on the results.

1.3 Organization

This work is organized in seven chapters. Chapter 1 corresponds to the introduction of the topic explored in the work, along with motivation and objectives. Chapter 2 covers important theoretical fundamentals of reservoir engineering, production engineering and automatic control focused on PID controllers. Chapter 3 brings the literature review about subsurface-surface integration and non-physical oscillation problems in explicit coupling. Chapter 4 describes the methodology adopted to minimize the explicit coupling oscillation problems in the case study. Chapter 5 presents the application of the methodology, with details of the simulation model (reservoir and production systems) and data used. Chapter 6 summarizes the principal results and discussions. Chapter 7 ends with conclusions and suggestions for future work.

2 THEORETICAL BACKGROUND

This chapter covers key concepts of reservoir engineering, production engineering and automatic control focused on proportional-integral-derivative controller (PID controller or three term controller), which are important for the comprehension of reservoir and production systems integration and solution of explicit coupling non-physical oscillation problems.

2.1 Petroleum production system

Petroleum production involves two distinct but intimately connected general systems: the reservoir, which is a porous media with unique storage and flow characteristics; and the artificial structures, which include the well, bottom-hole, and wellhead assemblies, as well as the surface gathering, separation, and storage facilities (Economides et al., 2013).

According to Guo et al. (2007) a complete oil and gas production system (Figure 2.1) consists of a reservoir, well, flowline, separators, pumps, and transportation pipelines. The reservoir supplies wellbore with crude oil and gas. The well provides a path for the production fluid to flow from the bottom-hole to the surface and offers a means to control the fluid production rate (choke). The flowline leads the production fluid to separators. The separators remove gas and water from the crude oil. Pumps and compressors are used to transport oil and gas through pipelines to sale points.

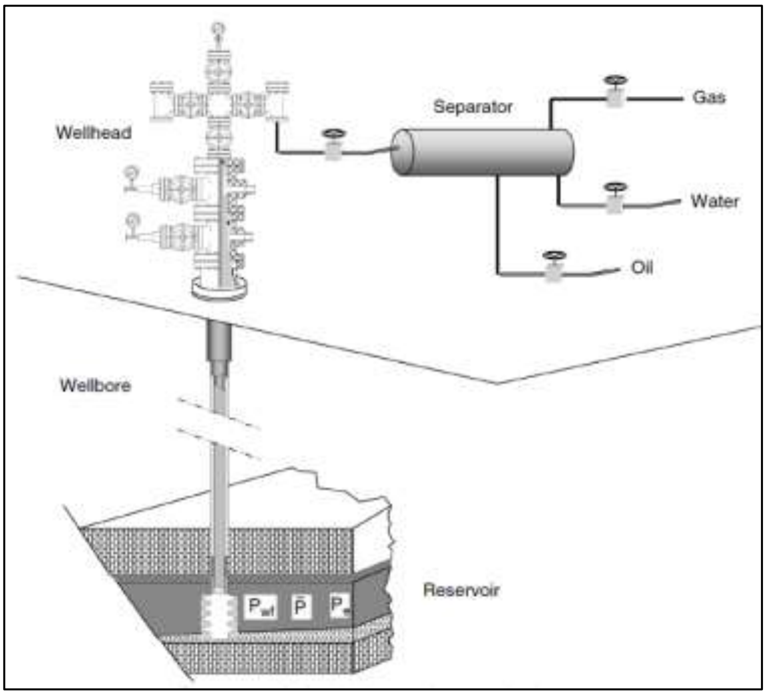

Figure 2.1: Petroleum production system (Guo et al., 2007).

2.2 Petroleum reservoir

2.2.1 Fluid flow in porous media

The basic equation to describe the fluid flow in porous media caused by a potential difference is known as the diffusivity equation (Equation 2.1), and it is derived from three fundamental physical principals: (1) the principal of conservation of mass, (2) an equation of motion (Darcy's law), and (3) an equation of state (Lee et al., 2003).

$$\frac{\partial^2 p}{\partial r^2} + \frac{1}{r}\frac{\partial p}{\partial r} = \frac{\phi \mu c_t}{k}\frac{\partial p}{\partial t} \quad \textbf{Equation 2.1}$$

In the derivation of Equation 2.1 it is assumed: radial flow; laminar (or Darcy) flow; porous media has constant permeability and compressibility; negligible gravity effects; isothermal conditions; fluid with small, constant compressibility (Lee et al., 2007).

Equation 2.1 is second order with respect to space and first order with respect to time, therefore two boundary conditions and one initial condition (always assumed that the reservoir is at uniform and constant initial pressure, p_i, before production begins) are required for its solution. The three most common solutions are: (1) transient radial flow, (2) pseudosteady-state radial flow, and (3) steady-state radial flow.

1) Transient radial flow (Equation 2.2): occurs at early producing times when the effects of the outer boundaries of the reservoir are not seen, thus the reservoir acts as if there were no boundaries; well represented as a "line source", in other words, the wellbore is infinitesimally small ($r_w \rightarrow 0$); and well produces at constant rate (Lee et al., 2003).

$$p(r,t) = p_i + \frac{q\mu}{4\pi kh} E_i(-x) \quad \textbf{Equation 2.2}$$

where E_i (x) is the exponential integral and x is given by Equation 2.3:

$$x = \frac{\phi \mu c_t r^2}{4kt} \quad \textbf{Equation 2.3}$$

For $x < 0.01$ (for large values of time or for small distances, such as at the wellbore), the exponential integral [$-E_i(-x)$] can be approximated by [$-\ln(\gamma x)$], where γ is Euler's constant and is equal to 1.78 (Economides et al., 2013).

Finally, introducing variables in oilfield units as listed in table 2.1, including the skin factor (s), and converting the natural log to log base 10, Equation 2.2 becomes (Economides et al., 2013):

$$p_{wf} = p_i - \frac{162.6qB\mu}{kh}(\log t + \log \frac{k}{\phi\mu c_t r_w^2} - 3.23 + 0.87s)$$ **Equation 2.4**

Table 2.1: Typical units for reservoir and production engineering calculations (Economides et al., 2013).

Variable	Oilfield Unit	SI Unit	Conversion (Multiply SI Unit)
Area	Acre	m^2	2.475 x 10^{-4}
Compressibility	psi^{-1}	Pa^{-1}	6897
Length	Ft	m	3.28
Permeability	Md	m^2	1.01 x 10^{-15}
Pressure	Psi	Pa	1.45 x 10^{-4}
Rate (Oil)	STB/d	m^3/s	5.434 x 10^5
Rate (Gas)	MSCF/d	m^3/s	3049
Viscosity	Cp	Pa*s	1000

2) Pseudosteady-state radial flow (Equation 2.5 in oilfield units): occurs when all the boundaries are felt in a closed (bounded) reservoir with no-flow boundaries; and cylindrical source well produces at constant rate (Lee et al., 2003).

$$p_{wf} = \overline{p} - \frac{141.2qB\mu}{kh}\left(\ln \frac{0.472r_e}{r_w} + s\right)$$ **Equation 2.5**

3) Steady-state radial flow (Equation 2.6 in oilfield units): occurs theoretically at long times in a constant pressure outer-boundary reservoir; and cylindrical source well produces at constant rate (Lee et al., 2003).

$$p_{wf} = p_e - \frac{141.2qB\mu}{kh}(\ln \frac{r_e}{r_w} + s)$$ **Equation 2.6**

2.2.2 Inflow Performance Relationship (IPR)

When the flow regime is stabilized (pseudosteady-state or steady-state), it is the recommended moment to calculate a reliable estimation of productivity capacity for a producer well (productivity index), and injectivity capacity for an injector well (injectivity index) (Ahmed, 2005).

For pseudosteady-state and single phase flow, the productivity index (Equation 2.7) and injectivity index (Equation 2.8) are constant values.

$$PI = \frac{q_{production}}{\overline{p} - BHP}$$ **Equation 2.7**

$$II = \frac{q_{injection}}{BHP - \overline{p}}$$ **Equation 2.8**

It is a common practice to graph the inflow performance relationship (IPR), which for a producer well is a curve that represents the available pressure for production (Figure 2.2), and for an injector well represents the available pressure for injection (Figure 2.3).

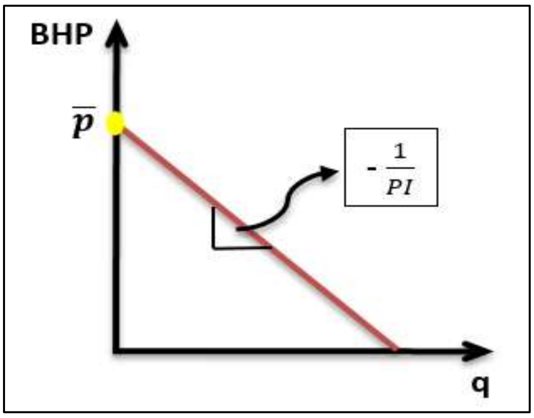

Figure 2.2: Single phase IPR curve of producer well.

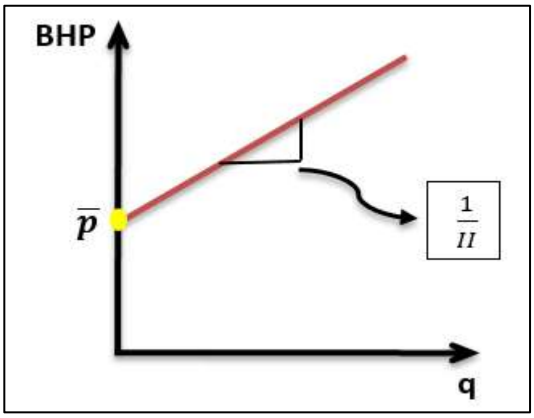

Figure 2.3: Single phase IPR curve of producer well.

2.3 Reservoir simulation

Reservoir simulation combines physics, mathematics, reservoir engineering, and computer programming to develop a tool for predicting hydrocarbon-reservoir performance under various operating conditions (Ertekin et al., 2001).

According to Batycky (2007) the purpose of simulation is estimation of field performance (e. g., oil recovery) under one or more producing schemes. Whereas the field can be produced only once, at considerable expense, a model can be run many times at low expense over a short period. Observation of model results that represent different producing conditions aids the selection of an optimal set of producing conditions for the reservoir.

According to Erteking et al. (2001) reservoir simulation is generally performed in the following steps:

1) Set the study objective: the first step of any successful simulation study is to set clear achievable objectives.
2) Acquire and validate all reservoir data: only the data required to meet the objectives of the study should be incorporated into the simulation model.
3) Construct the reservoir model: the reservoir is divided into grid blocks and formation properties, such as porosity, directional permeability, and net-pay thickness, are assigned to these grid cells in a process called upscaling.
4) History match the reservoir model: once the simulation model has been built, it must be history matched with available production data, because much of the data in a typical simulation model is not known for certain but is the result of engineers' and geologists' interpretations.
5) Prediction phase: In this last step, various production schemes are evaluated and sensitivity analyses of production and reservoir parameters are performed.

2.4 Fluid flow in the production system

2.4.1 Flow performance

The multiphase flow performance depends on geometrical variables (diameter and length) of the producing string, fluid rate, fixed pressure variable (i. e., well head pressure WHP), water faction variable (i. e., water cut), gas fraction variable (i. e., gas-liquid ratio), fluid PVT properties, and the distribution of the phases in the pipe (Magalhaes, 2005) (Figures 2.4 and 2.5).

The total pressure drop in the production system (Equation 2.9) can be obtained by solving the mechanical energy balance (Fox et al., 2004).

$$\Delta p_{total} = \Delta p_{PE} + \Delta p_{KE} + \Delta p_f + \Delta p_W + \Delta p_S \qquad \textbf{Equation 2.9}$$

In Equation 2.9, the total pressure drop (Δp_{total}) is composed by pressure drop due to potential energy change (Δp_{PE}), pressure drop due to kinetic energy change (Δp_{KE}), frictional pressure drop (Δp_f), pressure drop caused by an external machine like a pump or turbine (Δp_W), and pressure drop due to pipe fittings like a choke (Δp_S).

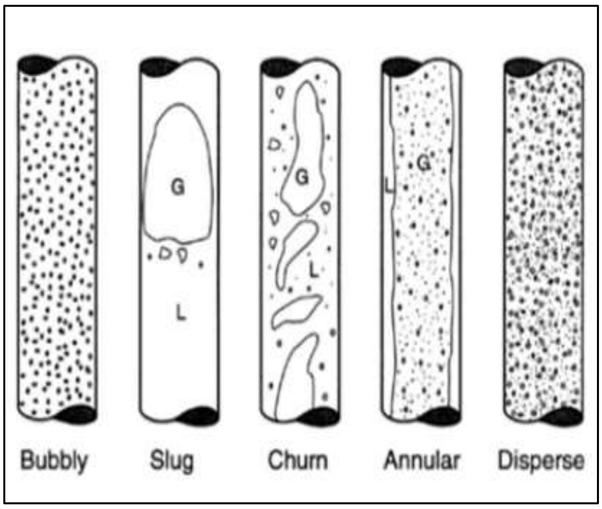

Figure 2.4: Typical flow regimes of gas/liquid mixture in vertical wells (Shoham, 2006).

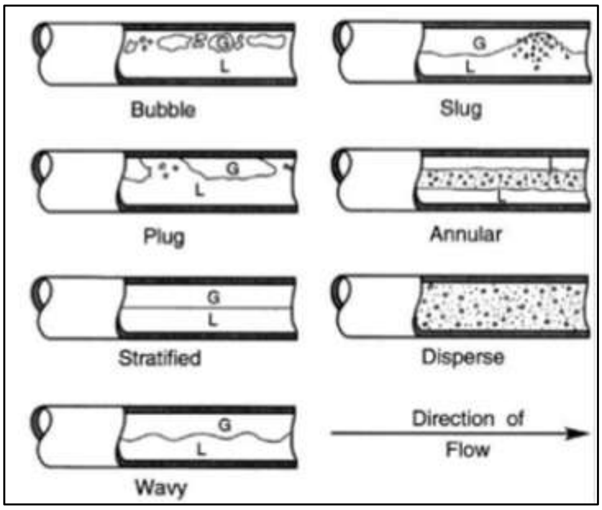

Figure 2.5: Typical flow regimes of gas/liquid mixture in horizontal wells (Shoham, 2006).

For gas-liquid flow there are many different correlations that have been developed to calculate pressure gradients and thus total pressure drop, ranging from simple empirical models to complex deterministic models. Detailed treatment of several of these correlations can be found in Brill and Mukherjee (1999).

The two most commonly used two-phase flow correlations for oil wells are: the modified Hagedorn & Brown method (Brown, 1977) and the Beggs & Brill (1973) method with the Payne et al. (1979) correction (Economides et al., 2013). The first was developed for vertical/upward flow and is recommended only for near vertical wellbores, while the Beggs & Brill correlation can be applied for any wellbore inclination and flow direction. For gas wells that are also producing liquid, the Gray (1974) correlation is recommended.

2.4.2 Outflow Performance Relationship (OPR)

It is a common practice to graph the Outflow Performance Relationship (OPR), which for a producer well is a curve based on Equation 2.9 and represents the required pressure for production or injection (Figure 2.6).

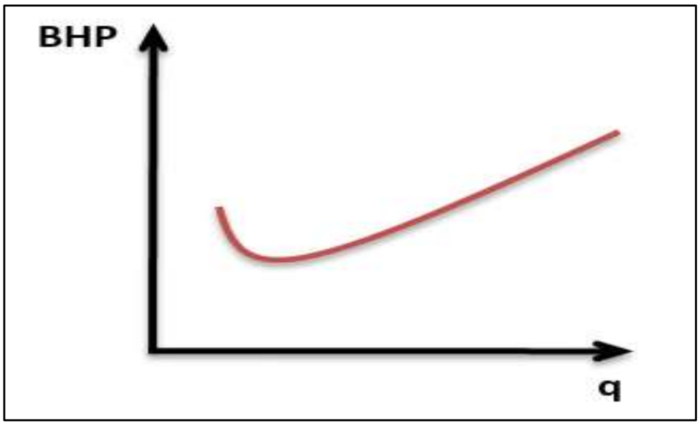

Figure 2.6: OPR curve of producer well.

The OPR curve is determined over a range of flow rates. For each value of flow rate, the total distance of the conduit is divided into increments small enough that the flow properties, and hence the pressure gradient (calculated based on a correlation), are almost constant in each increment. Summing the pressure drop in each increment, the overall pressure drop is obtained. This stepwise calculation procedure is generally referred to as pressure traverse calculation.

Since both the temperature and pressure will be varying along the pipe, a pressure traverse calculation is usually iterative. According to Brill & Beggs (1978) and Schiozer (1994), the pressure traverse calculations can be performed either by fixing the length increment and calculating the pressure drop, or by fixing the pressure drop and finding the depth interval over which this pressure drop would occur.

2.5 Well deliverability

Many of the components of the petroleum production system can be considered together by graphing the inflow performance relationship (IPR) and the outflow performance relationship (OPR). Most of times both curves are plotted relating bottom-hole pressure (BHP) to surface production rate.

For a producer well, the intersection of the IPR curve with the OPR curve yields the well deliverability (operating point), an expression of what a well will actually produce for a given operating condition (Figure 2.7).

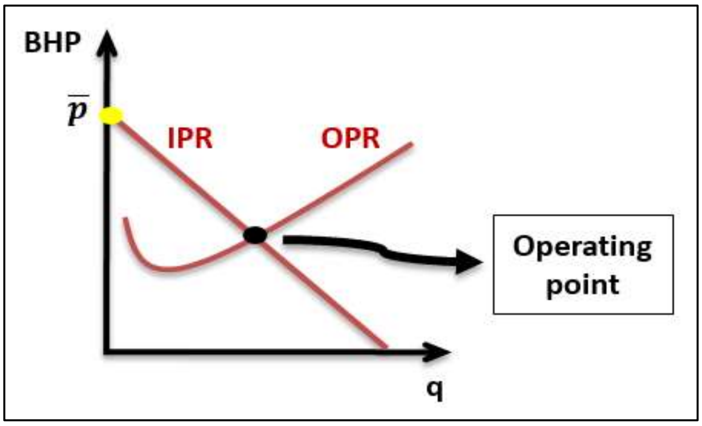

Figure 2.7: Well deliverability of a single phase producer well.

For an injector well, one possible way to calculate the operating point is based on the intersection of maximum allowed bottom-hole pressure, which is a well restriction imposed by the network system, and IPR curve (Figure 2.8).

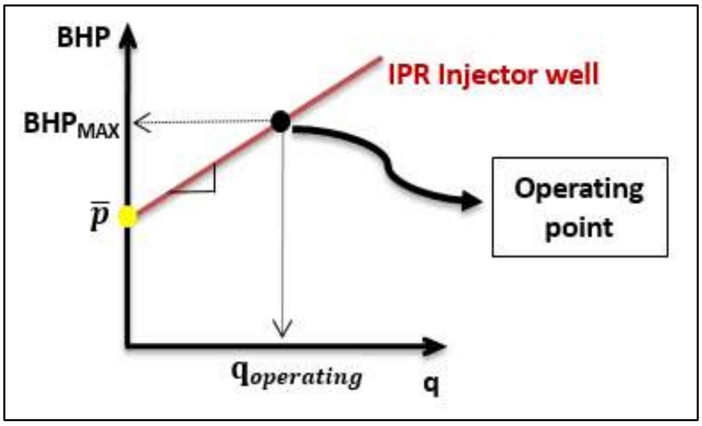

Figure 2.8: Well deliverability of single phase injector well.

2.6 Automatic control

Automatic control in engineering and technology is a wide generic term covering the application of mechanisms to operate and regulate processes without continuous human intervention.

According to Dorf & Bishop (2017), automatic control continually measures process operating parameters such as temperatures, pressures, levels, flows, speeds, positions and concentrations, and then makes decisions to, for example, open valves, slow down pumps and turn up heaters so that selected process measurements are maintained at desired values avoiding oscillation.

According to Haugen (2004) and Güyagüler et al. (2009), due to control engineering: (1) petroleum products can be produced in refineries under specific levels of sulfur, nitrogen and oxygen; (2) field desired operating conditions can be maintained in reservoir simulation; (3) a supply ship will stay at or close to a specified position without anchor; (4) the temperature and the composition in a chemical reactor will follow the specifications defined to give an optimum production; and (5) a turbine generator produces AC voltage of the specified frequency of 50 Hertz.

When it comes to the control types, fundamentally there are two: open loop control and closed loop control (Figure 2.9).

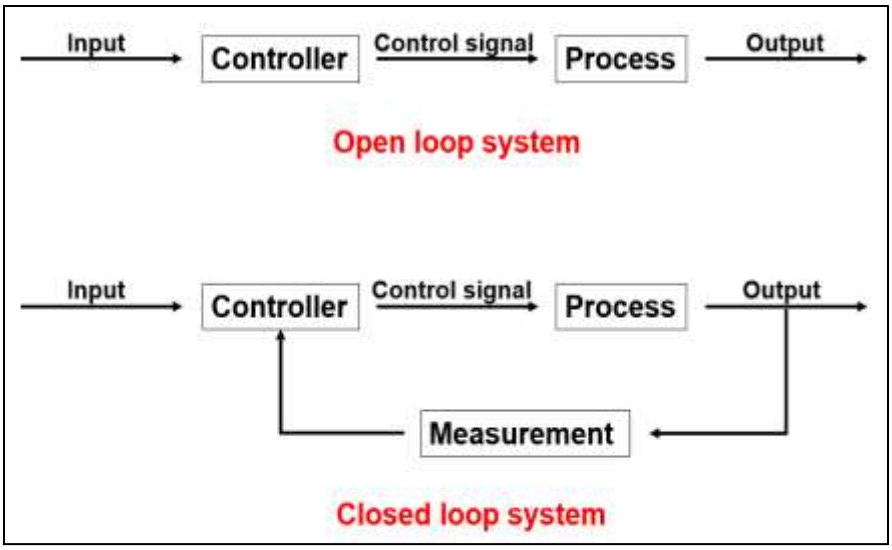

Figure 2.9: Open and closed loop control systems.

In open loop control, the control action from the controller is independent of the process output whereas in closed loop control (feedback control), the control action from the controller is dependent on the process output.

The application of open loop control is simpler since the feedback mechanism is not required in the system. However, its implementation is feasible if the system functionality is completely known.

2.6.1 Closed loop control (feedback control)

The goal of the feedback control is to keep the measured process variable (process output) at the set point value in spite of the disturbances (Akakpo, 2016).

The general block diagram of a feedback control loop can be represented in Figure 2.10.

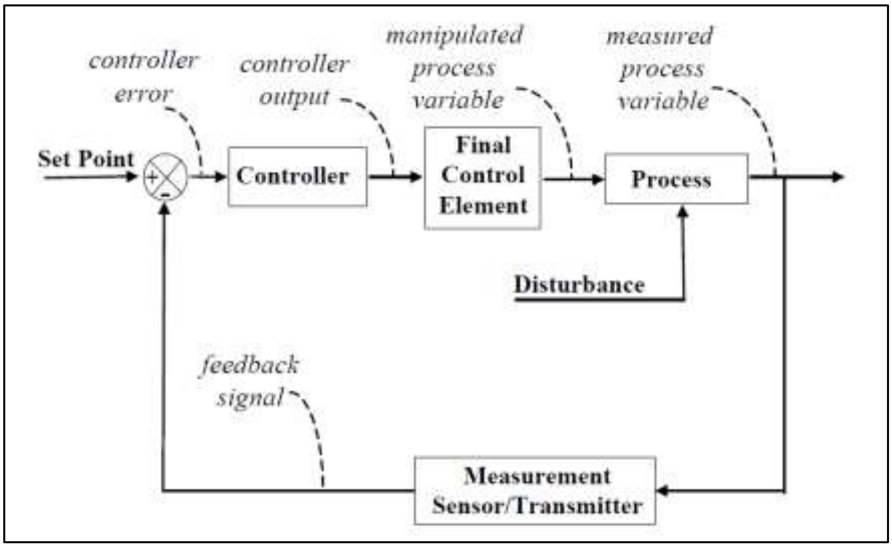

Figure 2.10: General closed loop block diagram.

Following the diagram of Figure 2.10, according to Cooper (2005), Ogata (2010) and Dorf & Bishop (2017), a sensor obtains the measured process variable (variable to be controlled in order to become equal or sufficiently close to the set point) and transmits, or feeds back, the signal to the controller. This measurement feedback signal is subtracted from the set point (desired or specified value for the measured process variable) to obtain the controller error. The error is used by the controller to compute a controller output signal. The signal causes a change in the mechanical final control element (i. e., valve), which in turn causes a change in the manipulated process variable (variable that the controller uses to control or manipulate the process). An appropriate change in the manipulated variable works to keep the measured process variable at the set point regardless of unplanned changes in the disturbance variable (undesirable non-controlled input variable to the process).

2.6.2 PID controller

The proportional-integral-derivative controller (PID controller or three term controller) is a control loop feedback mechanism widely used in industrial control systems and a variety of other applications requiring continuously modulated control. The popularity of this type of controller can be attributed to its robust performance and function simplicity, which allows engineers to operate them in a simple and straightforward manner.

To understand the PID controller fundamental operation (Figures 2.11 and 2.12), a general explanation is presented: basically the controller continuously calculates an error value (*e(t)*) as the difference between a desired set point (*SP*) and a measured process variable (*y(t)*), and applies a correction based on proportional, integral and derivative terms. It is important to bear in mind that the controller attempts to minimize the error over time by adjustment of its output (*u(t)*) to a new value determined by the sum of the control terms as shown in Equation 2.10 (continuous or analog PID).

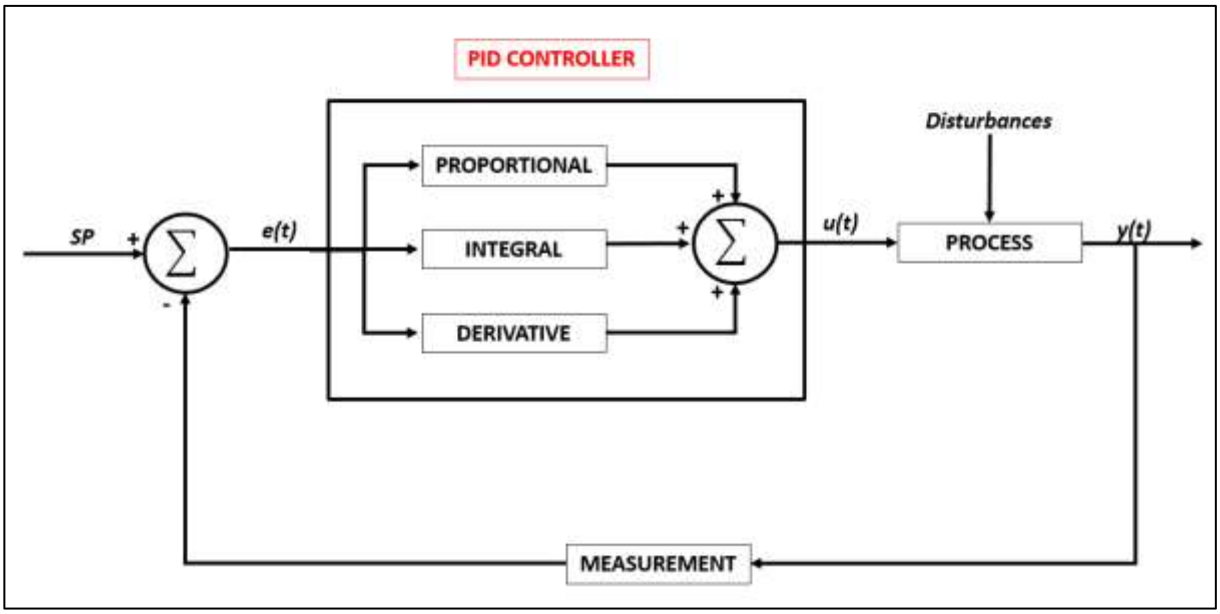

Figure 2.11: Block diagram of PID controller.

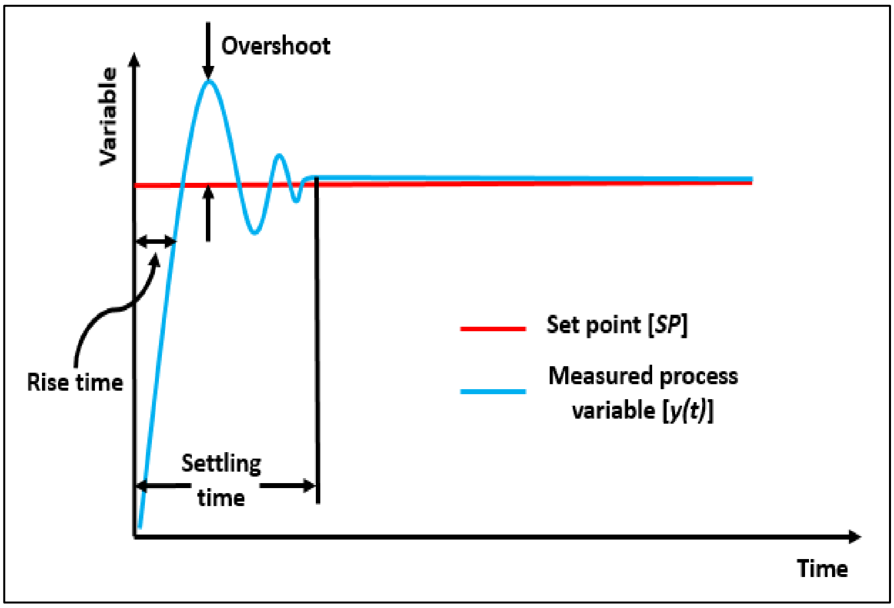

Figure 2.12: Example of possible PID controller action, operating on a second-order differential equation by the application of a step change in the set point. In this case, the

performance on the controller is measured by the quantities depicted in the graph (Ogata, 2010).

$$u(t) = u_{bias} + \underbrace{K_C e(t)}_{Proportional} + \underbrace{\frac{K_C}{\tau_I}\int e(t)dt}_{Integral} + \underbrace{K_C \tau_D \frac{de(t)}{dt}}_{Derivative} \qquad \textbf{Equation 2.10}$$

Another way to represent the PID controller is by its discrete or digital function, which can be obtained from the discretization of Equation 2.10, and is used in computers since they operate in discrete time (Franklin et al., 1998). Basically, there are two main forms of discrete PID control algorithms: the absolute or positional algorithm (Equation 2.11) and the incremental or velocity algorithm (Equation 2.12).

$$u(t_k) = u_{bias} + K_C\left[e_k + \left(\frac{\Delta t}{\tau_I}\sum_{j=1}^{k} e_j\right) + \frac{\tau_D}{\Delta t}(e_k - e_{k-1})\right] \qquad \textbf{Equation 2.11}$$

$$u(t_k) = u(t_{k-1}) + \underbrace{K_C\left[(e_k - e_{k-1}) + \frac{\Delta t}{\tau_I}e_k + \frac{\tau_D}{\Delta t}(e_k - 2e_{k-1} + e_{k-2})\right]}_{\Delta u(t_k)} \qquad \textbf{Equation 2.12}$$

The velocity form of the discrete PID controller is an attractive alternative to the positional one, since it avoids computing the summation in Equation 2.11, and it does not require specification of the bias term (Seborg et al., 2016).

When it comes to the representation of the PID controller algorithms (Equations 2.10 to 2.12), it is important to mention that some authors prefer to use PID gains instead of PID parameters. Therefore, (K_C) is replaced by the proportional gain (K_p), (K_C/τ_I) is replaced by the integral gain (K_i), and $(K_C\tau_D)$ is replaced by the derivative gain (K_d).

According to Haugen (2004) and Seborg et al. (2016) either the continuous PID or the discrete PID can have three components (proportional, integral and derivative), and each one has its own characteristics as following:

1) <u>Proportional (present)</u>: computes a contribution to the control output proportionally to the current error size, thus its influence will grow when the error increases; and action towards the set point value is quicker than the integral term, but more sluggish than the derivative term.

2) Integral (past): continually sums or accumulates error over time, thus its influence increases when either positive or negative error persists for some time; and action towards the set point value is relatively sluggish.
3) Derivative (future): based on slope or rate of change in error; influence grows when error is rapidly changing in order to slow down such movement; action towards the set point is very fast (abrupt); and very sensitive to noise because differentiation amplifies noise, therefore can cause the process to be unstable.

The PID implementation can be done in four different ways: P controller ($\tau_I \rightarrow \infty$ and $\tau_D = 0$), PI controller ($\tau_D = 0$), PD controller ($\tau_I \rightarrow \infty$), and PID controller (Astrom & Hagglund, 1995). From those, P only controller is driven by a non-zero error, therefore it generally operates with a steady-state error; and PI controller is the most common form, because the derivative term is sensitive to measurement noise, while the absence of integral term may prevent the system from reaching the set point value.

Another important aspect of the PID controller is the tuning phase, which means the selection of appropriate gains or coefficients as in Equations 2.10, 2.11 and 2.12. There are many design techniques used to determine the best choice of parameters for each individual process. In general, for complex systems, empirical selection may be used. To this end, the Ziegler & Nichols (1942) method is widely to select the ideal values of K_C, τ_I and τ_D that will drive the process to stability with error close to zero. Determination of the gains can also be done manually. More details about manual tuning can be found in Annex A.

3 LITERATURE REVIEW

This chapter is dedicated to present: (1) the literature review towards subsurface and surface integration techniques and (2) non-physical oscillation problem that may appear when explicit coupling method is implemented.

3.1 Advances in reservoir and production systems integration

The first generation of computational reservoir simulation models (standalone) treated fluid flow in porous media and well perforation “isolated” from the fluid flow in production systems. In this case, the simulation does not take into account directly pressure losses in the well and gathering systems, instead well constraints are estimated in a simplified manner with assistance of a production simulator attempting to guarantee the elevation and production of fluids delivered by the reservoir (Magalhaes, 2005). However, IAM (Integrated Asset Modeling) techniques started to be implemented when pressure drop tables were added to reservoir simulators as a trial to represent with better precision the well and gathering systems.

Nowadays, more sophisticated IAM methodologies, such as explicit and implicit couplings, are receiving higher importance in scenarios of oil and gas field production, especially when multiple reservoirs are connected to platforms with operational restrictions, subsea separation units, intelligent wells, mixture of fluids with different compositions and other complex production systems.

The application of IAM technique brings higher confidence to projects, which is a requirement for optimization of production and maximization of economic indicators as net present value (NPV).

During the last 40 years, different methods to couple reservoir and network models were developed and studied by a number of investigators (Liang et al., 2013).

Dempsey et al. (1971) presented a technique that iteratively solved reservoir, well and gathering system models to accurately evaluate gas field deliverability. The concept was extended to Black oil systems by Startzman et al. (1977) and the scheme was modified by Emanuel & Ranney (1981) to operate efficiently when dealing with multiphase flow in large-scale problems. Hepguler et al. (1997) and Tingas et al. (1998) implemented similar schemes to couple existing commercial reservoir and network simulators. Trick (1998) extended the work of Hepguler et al. (1997) by moving the coupling to newton iteration level.

Litvak & Darlow (1995) presented a coupled compositional simulation with a commercial reservoir simulator. They also described an implicit scheme in which the reservoir and surface network were solved simultaneously by treating the network nodes as additional grid blocks of the reservoir model.

Schiozer & Aziz (1994) investigated the application of domain-decomposition techniques to well subdomains to accelerate iteratively coupled simulation. Byer et al. (1999) presented a preconditioning technique that can accelerate implicit coupled models solved with extended well subdomains.

Coats et al. (2004) and Shiralkar & Watts (2005) presented different combined formulations on the basis of extending the existing reservoir-simulation equations to include implicitly network-model equations.

As mentioned before, many advances in IAM have been done so far, but in order to make the application of this technique broader and more efficient, new implementations continue to be developed (Rotondi et al., 2008).

3.2 Types of Integrated Asset Modeling (IAM)

The integration of subsurface-surface systems can be performed applying standalone model and specialized IAM techniques. The nomenclature of IAM techniques varies in the literature. In this work, it is used the same adopted by Hohendorff Filho & Schiozer (2016):

1) <u>Decoupled method</u>: characterized by the addition in the reservoir simulator, pre-calculated tabulated data or data files containing pipe multiphase flow information, representing the pressure required to produce or inject (outflow performance relationship) (Bento, 2010).
2) <u>Explicit coupling</u>: characterized by a combination of multiple simulators in an automated fashion, where each model simulates one or more parts of the field (Hiebert et al., 2011; Hohendorff Filho & Schiozer, 2014). The exchange of data between simulators (balancing) is automated, occurs in discrete points, and happens through the use of standard interfaces or simple methods for file sharing from a common repository (Hiebert et al., 2011) (Figure 3.1).

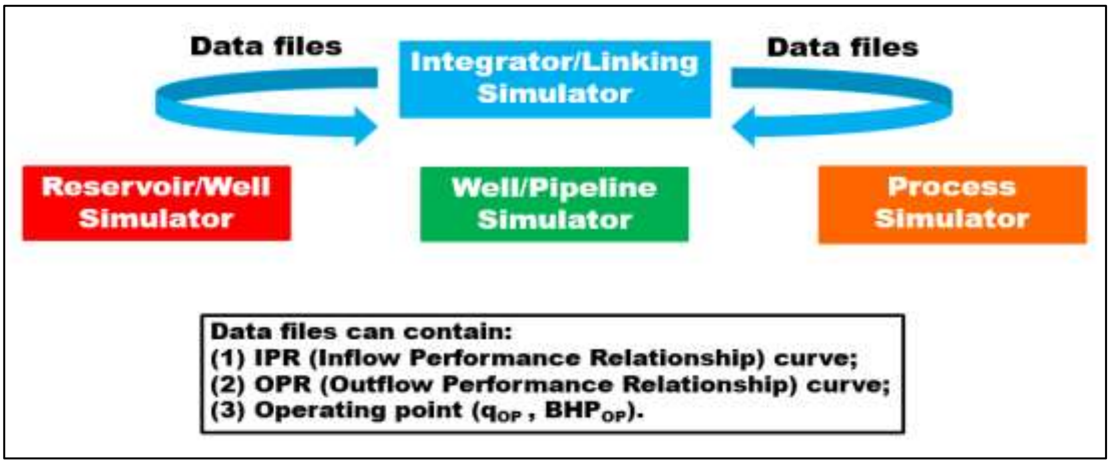

Figure 3.1: Generic example highlighting coupling program managing the connections of simulators in an explicit coupling process (modified from Toby, 2014).

There are two important aspects that need to be considered when explicit coupling technique is applied: balancing frequency between reservoir and production systems and coupling location.

According to Guyaguler et al. (2010), explicit coupling can be performed applying three different balancing frequencies (Figure 3.2):

a. Time step lagged: balancing takes place at the beginning of every time step.
b. Iteratively lagged: balancing takes place in the first few Newtonian interactions of every time step (partially implicit coupling). This technique is restricted to a few number of simulators with suitable interfaces.
c. Periodic: balancing is carried out periodically with a predefined fixed period length, not necessarily corresponding to the time step length used by the reservoir simulator. In scenarios that oscillations are not present, this method can be used to reduce the balancing frequency between simulators in order to decrease the simulation run time.

According to Barroux et al. (2000), the coupling location can be anywhere in the system, but the usual node is bottom-hole, surface or manifold.

In order to present this technique schematically, Figure 3.3 shows one example of time step lagged explicit coupling, coupled at the bottom-hole level.

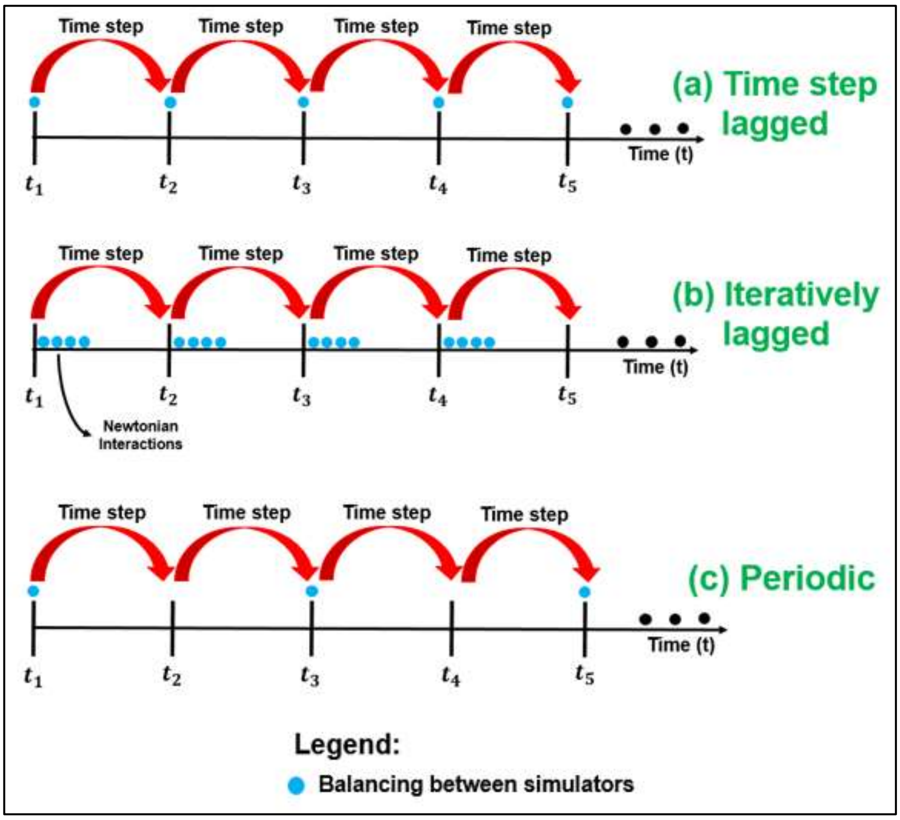

Figure 3.2: Sketch of three possible balancing frequencies in explicit coupling.

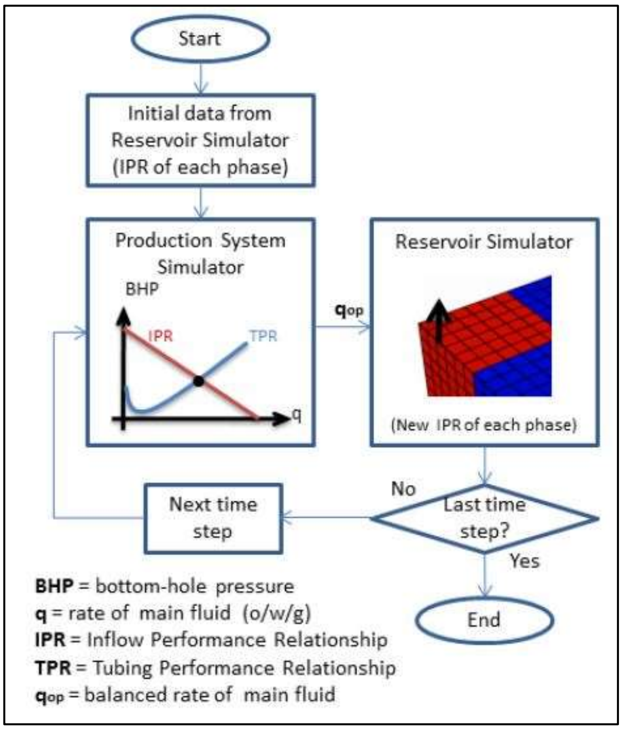

Figure 3.3: Flowchart of time step lagged explicit coupling (Hohendorff Filho & Schiozer, 2014), (TPR and OPR curves are the same).

3) Implicit coupling: a single simulator is used to perform the entire process, therefore the solution of all governing equations is calculated within the same framework, eliminating the need for connectivity and transfer of externalized data between different simulators (Hiebert et al., 2011). The results of the equations that represent the reservoir, well and gathering systems are inserted in the Jacobian matrix of the reservoir simulator.

3.2.1 IAM techniques discussion

The methodologies mentioned before have advantages and disadvantages associated:

1) Decoupled method: this is a simple IAM technique and at the same time still widely used in the petroleum industry. However, as drawback: (1) it may not be applied in complex scenarios involving, for instance, mixture of compositional fluids produced from multiple reservoirs or complex production systems, and (2) inaccuracies can be introduced in the calculations because of the possibility of interpolation or extrapolation of insufficient tabulated data.
2) Explicit coupling: advantages of explicit methodology are related to low computational time and effort when including a database of outflow performance relationship curves just for support, great flexibility in well management alternatives and freedom to select reservoir and production system software (Victorino et al., 2016). On the other hand, there is a chance of instabilities occurrence in the process (results with non-physical oscillation problems), which can be mainly attributed to the non-continuous balancing between simulators (Cao et al., 2015).
3) Implicit coupling: the main advantage of this method is related to the possibility of convergence of all models without oscillation (Hohendorff Filho, 2012). However, the negative aspects include: (1) it is not widely available in simulation packages, and (2) simulations can be characterized by high computational time/effort due to complexity of problem formulation.

3.3 Explicit coupling non-physical oscillation problem

As mentioned before in section 3.2.1, the explicit coupling can yield in many cases numerical solutions with non-physical oscillations. Figures 3.4, 3.5 and 3.6 present examples of this issue.

In order to understand the reason why the non-physical oscillation problems can exist in the explicit coupling, it is important to comprehend this integration methodology as in

Figure 3.7: according to Zhang et al. (2017) at the beginning of any coupling time step, an IPR curve is generated for each well according to the reservoir simulation (number 1). This IPR curve is used as boundary condition to the network model to fully represent the subsurface flow. Once the network model is solved to find the new operating point for each well (number 2), either the flow rate or bottom-hole pressure from the new operating point is imposed on the particular well in the reservoir model (number 3) to continue the subsurface flow simulation until the next coupling time step.

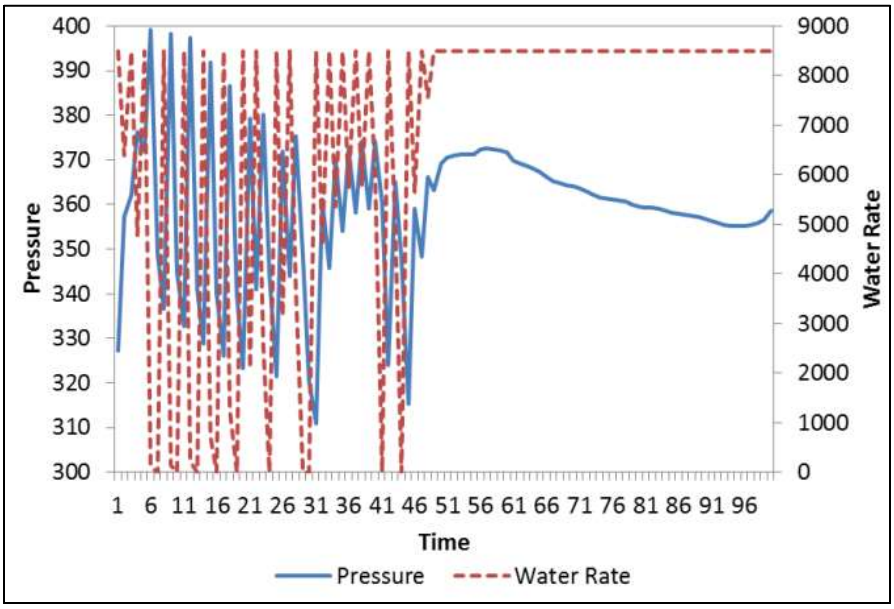

Figure 3.4: Pressure and water rate non-physical oscillation in explicit coupling (Hohendorff Filho & Schiozer, 2016).

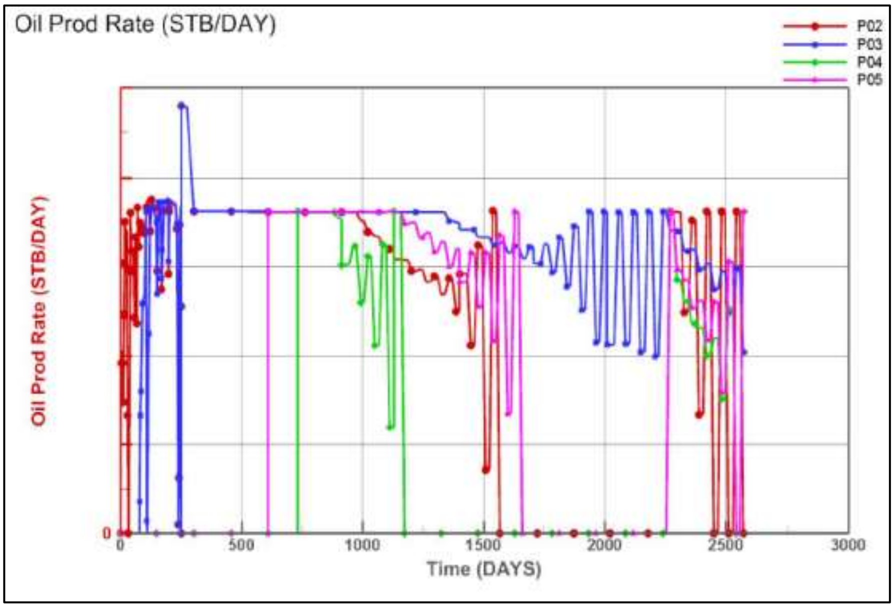

Figure 3.5: Oil rate non-physical oscillation in explicit coupling (Zhang et al., 2017).

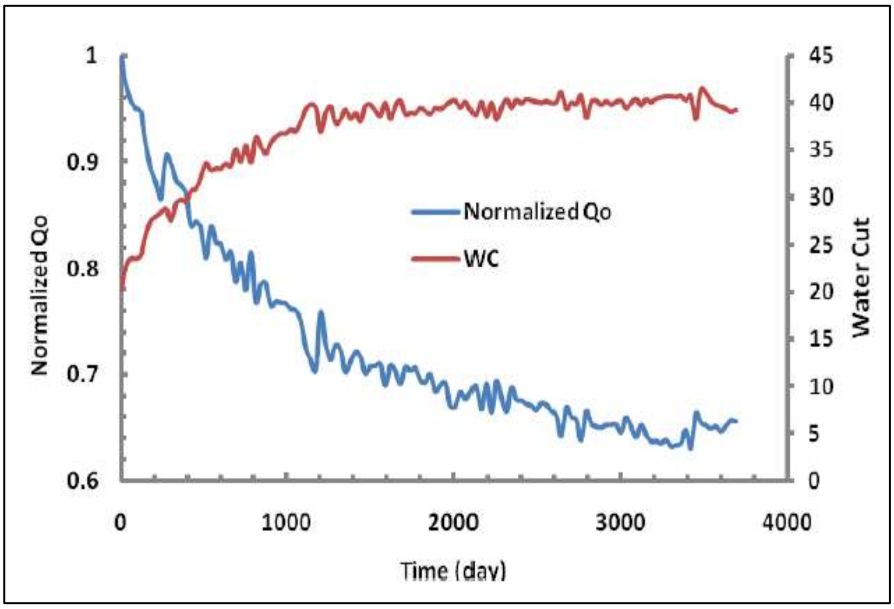

Figure 3.6: Normalized oil rate and water cut non-physical oscillation in explicit coupling (Hayder et al., 2011).

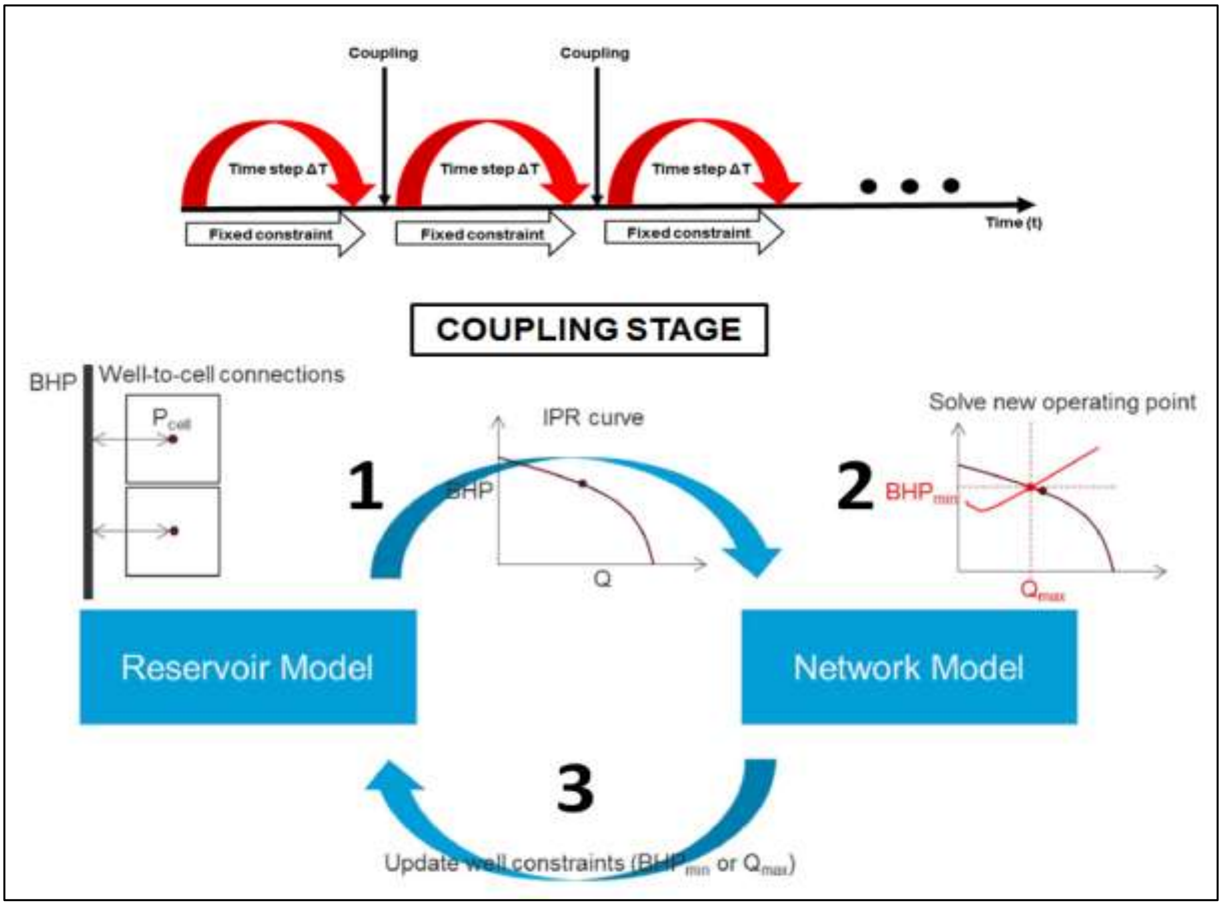

Figure 3.7: Sketch of explicit coupling process with simulation time domain, detailing the phase of data exchange between simulators in a discrete point (Zhang et al., 2017).

There are three important aspects in this process:

1) Reservoir and network models are solved sequentially without iteration;
2) Passage of information between two models is purely through IPR curves (from reservoir model to network model) and well operating constraints (from network model to reservoir model);
3) Reservoir simulator traditionally calculates IPR curve by solving the "well model", which is composed of many well-to-cell connections, and each connection is modeled by Peaceman equation (Peaceman, 1978), represented here by Equations 3.1 and 3.2 for producer and injector wells, respectively.

$$PI = \frac{q_{production}}{p_{block} - BHP} \qquad \textbf{Equation 3.1}$$

$$II = \frac{q_{injection}}{BHP - p_{block}} \qquad \textbf{Equation 3.2}$$

Several authors have studied the numerical instability that can occur in explicit coupled models. The main cause for non-physical oscillation problems is related to the fact that the traditionally calculated IPR at the beginning of the coupling time step may not be representative of the IPR during the entire coupling interval. The issue becomes even more critical because this IPR considers only the well and its completions cells (well block pressure) (Figure 3.8) representing an instantaneous behavior.

Feasible IPRs could be based on well influence area (drainage pressure) (Figure 3.9) (Al-Mutairi et al., 2010) because of a more stable pressure behavior of the drainage area.

During consecutive time steps, drainage pressure is generally less sensitive to changes due to fluid flow in porous media than the well block pressure. Therefore, when the IPR is calculated based on drainage pressure, it can be considered a reliable curve for the entire time step interval. However, process stability is not guaranteed in subsurface-surface explicit couplings using this type of IPR without special caution for every time step length (Δt), as shown in Figure 3.10 for large Δt.

Figure 3.11 depicts in more detail the oscillatory behavior of a single producer well when reservoir is coupled with network system in an explicit fashion. Initially, the flow rate obtained from the operating point and imposed as well boundary condition in the reservoir simulator for the first time step is very high (Figure 3.11 A). This high flow rate will cause a decrease in well block pressure at the end of the time step. Therefore the second IPR curve (traditional) will go down and consequently the second operating point flow rate will be a lot lower than the first one (Figure 3.11 B). This low flow rate is imposed as well boundary condition in the reservoir simulator for the second time step, and at the end the well block pressure will be higher than the last one, therefore the third traditional IPR curve will go up and the third operating point flow rate will be higher than the last one (Figure 3.11 C). This unstable process keeps happening in the subsequent coupling intervals.

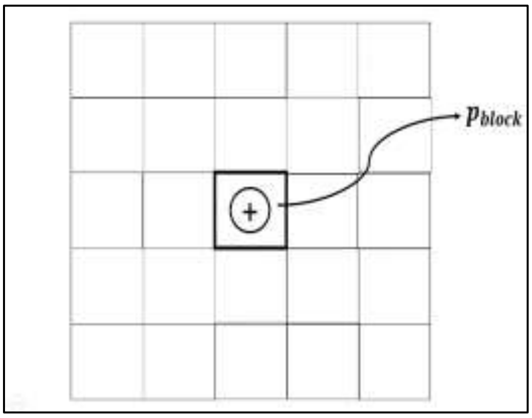

Figure 3.8: Scheme showing well block pressure in 2D reservoir grid.

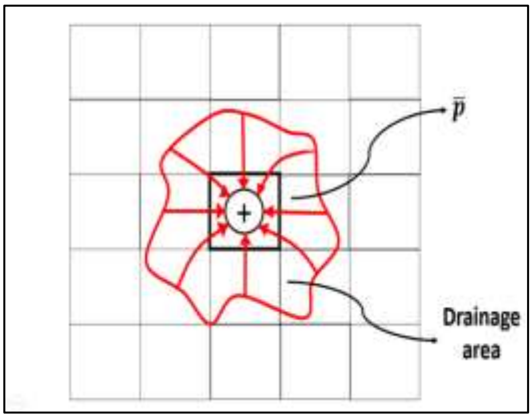

Figure 3.9: Scheme showing drainage pressure of a producer well in 2D reservoir grid.

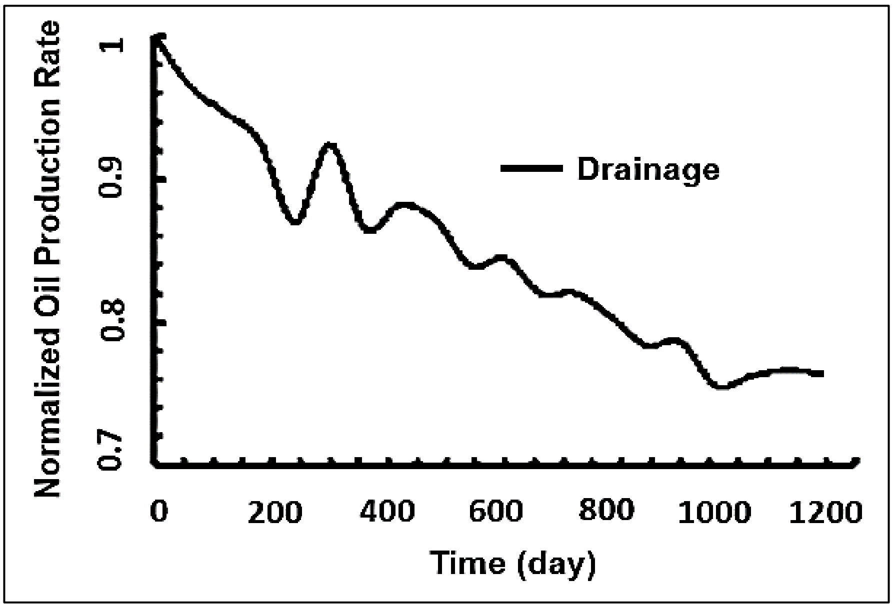

Figure.3.10: Instability in normalized oil production rate using IPR curve based on drainage pressure with large values of time step size (modified from Hayder et al., 2011).

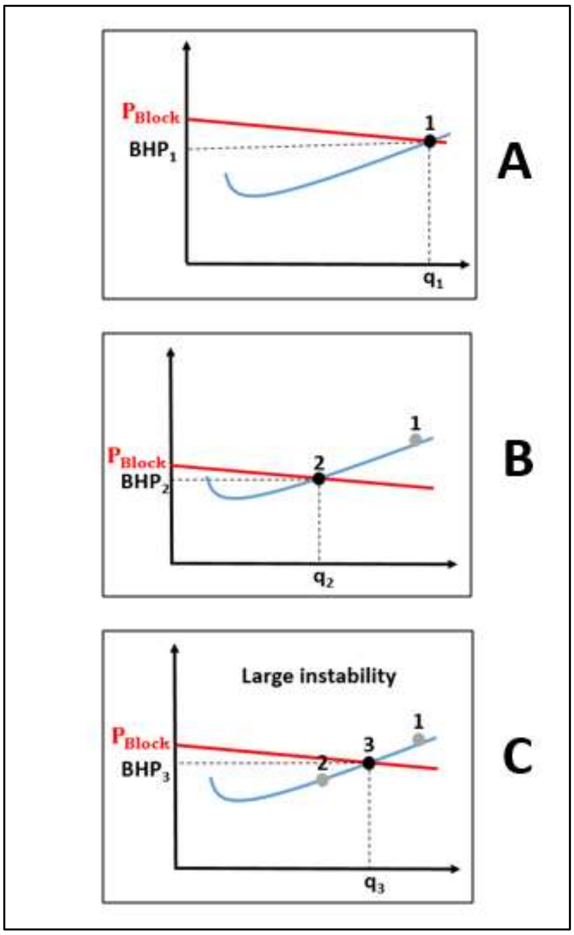

Figure 3.11: IPR curve (producer well) up and down shift between consecutive time steps.

A typical approach used to try to remedy the non-physical oscillation problem is the reduction of time step size (Δt) (Hohendorff Filho, 2012), but when it is not sufficient to suppress the oscillations, sophisticated methods have to be applied.

Many authors have proposed techniques to reduce or eliminate instabilities often present in integrations between subsurface-surface systems:

1) Güyagüler et al. (2010) developed an IPR calculation technique based on sub-domain calculations;
2) Liang et al. (2013) approach is based on the simulation of two simultaneous flow tests of all reservoir wells and calculation of IPRs based on drainage region of each well;
3) Hohendorff Filho & Schiozer (2016) developed an equation correlating well block pressure and flow rate, in order to correct the traditional IPR generated by the reservoir simulator;
4) Zhang et al. (2017) proposed a stabilized IPR calculation method based on analytical scaling and fast marching method;

5) Using a simple coupled model with adaptive time stepping technique, Redick (2017) applied a special PID controller algorithm proposedr by Gustafsson et al. (1988) to select the appropriate time step sizes.

None of the proposed methods mentioned before is universally acceptable to completely solve the non-physical oscillation problem of explicit coupling. Besides that, some techniques, especially the ones used to calculate the IPR curve based on drainage pressure, need extra simulations (addition of significant computational cost/effort) and may require access to reservoir internal code to be implemented.

Therefore, this work aim at minimizing the oscillation problem in a more straightforward fashion by the use of automatic control theory. This methodology has a vast application in the engineering field, including examples in the petroleum industry:

1) Smart well technology (Dilib & Jackson, 2012; Dilib et al., 2012);
2) Closed Loop Reservoir Management (CLRM) (Foss & Jensen, 2011);
3) Simulation of field processes as maintenance of average pressure and temperature within reservoir region, and prevention of gas/water coning for single and multiple wells (Güyagüler et al., 2009).

4 METHODOLOGY

In this chapter, general and PID application methodologies are presented with details.

4.1 General methodology

Reduction of explicit coupling oscillation problem is achieved in the case study, by a correction at each time step of traditional IPR (Inflow Performance Relationship) curve generated by reservoir simulator. In this case, IPR well block pressure (P_{Block}) is replaced by a value calculated based on the discrete incremental or velocity PID algorithm. This value possibly represents an estimation of well drainage pressure, called in this project stable pressure (P_{Stable}).

The task is accomplished by the implementation of two centralized and manually tuned PID controllers, which are designed by specification of three principal elements: set point, measured and manipulated variables.

The performance of new methodology is evaluated by comparison of local and global results with base case, which in this work is a reliable decoupled method with established known response. Finally, a sensitivity analysis study with K_C, τ_I and τ_D is done in a well varying each PID parameter independently.

4.2 PID application methodology

4.2.1 Formulated method

The explicit coupling between reservoir and production systems can cause production and injector wells to either keep opened with possible oscillations issues in bottom-hole pressures (BHP) and flow rates (q), or close as consequence of unstable solutions. Thus, a new methodology based on PID controller is implemented in order to minimize coupling instabilities. Figure 4.1 is the complete schematic flowchart considered to integrate reservoir and production systems simulators. It shows the stages performed in the coupling/integrator program at each time step considering PID controller as the technique applied to mitigate oscillation problems.

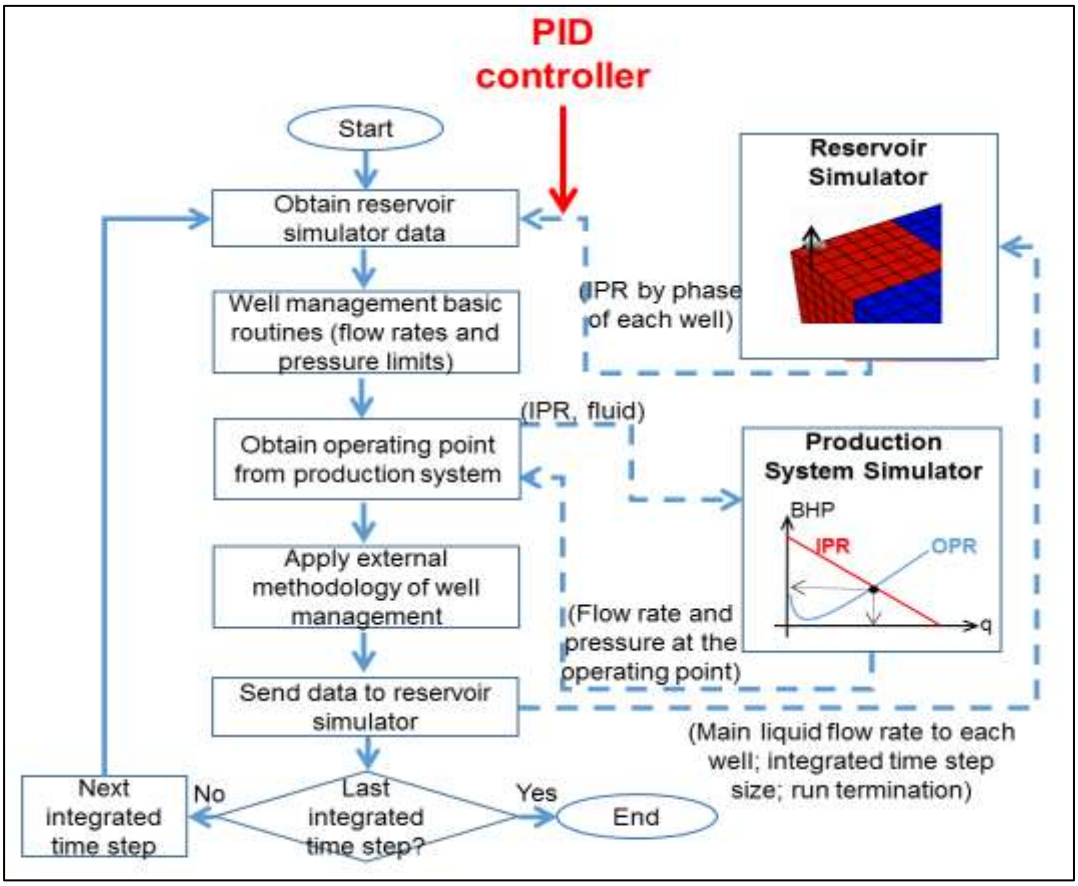

Figure 4.1: Flowchart of coupling program with PID controller (Hohendorff Filho, 2012).

In Figure 4.1, the PID controller, as defined by Equation 2.12, is implemented globally, i.e., a single control strategy is applied to all of the wells simultaneously. This is known as a centralized controller, as opposed to a decentralized controller, whereby multiple PID control strategies (one for each well) need to be defined. In the case study, two global PID controllers for wells presenting instability problems compose the methodology selected: one for the group of injectors and another for the group of producers.

Both controllers are tuned manually defining ideal values of K_C, τ_I and τ_D, guaranteeing the variation of total PID output $[u(t_k)]$ between -1 and 1, in order to lead the process to minimize oscillation problem avoiding controller saturation.

Constants K_C, τ_I and τ_D play the most important role in the process. A proper tuning can drive the system to stabilization with error close to zero while an incorrect tuning can keep the system oscillating or even destabilize completely.

Therefore, a sensitivity analysis study is done for the purpose to figure out the effect of each PID parameter in the results. This study is performed in a specific well using a PID controller individually tuned, and the influence of parameters is determined varying one while the other two are kept constant. Two different scenarios are considered in the analysis: (1) no step change in PID set point and (2) step change in PID set point value to examine controller action in the presence of steady-state error.

In order to check the new methodology performance in the case study, BHP and flow rate of injectors and producer wells presenting instabilities are compared with a base case (decoupled method). Besides that, a global comparison in terms of field total water injection rate and total oil production rate is done considering the two integration techniques: explicit coupling with PID controllers and decoupled method.

4.2.2 Details of PID controller action

At the beginning of each time step, the coupling program receives the IPR curve from reservoir simulator, then, applies a correction to it based on the PID controller actuation strategy (process described next), and finally, calculates a new operating point (q_{OP}, BHP_{OP}), which is possibly more representative for the entire coupling interval than the operating point calculated with the IPR without correction. It is important to note that the operating point expresses the condition the well is supposed to work during the time step.

Figures 4.2 and 4.3 show how the operating point is obtained for injector and producer wells respectively. Injector wells operating point is calculated by the intersection of maximum BHP, which is a well restriction imposed by network system, and IPR curve; while producer wells operating point is calculated by the intersection of IPR and OPR curves.

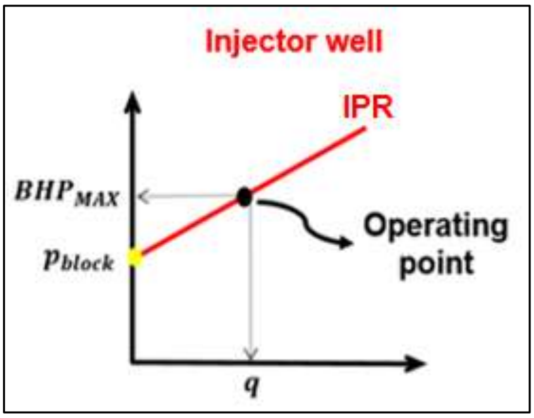

Figure 4.2: Well deliverability of injector well in UNISIM-I-D benchmark.

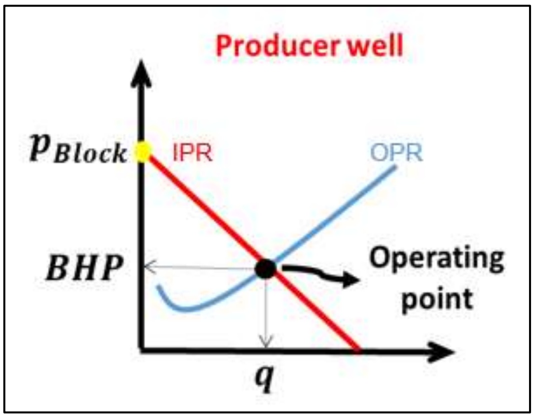

Figure 4.3: Well deliverability of producer well in UNISIM-I-D benchmark.

Once the operating point is obtained, the coupling program verifies if the flow rate of a particular well complies with the system maximum limits: (1) 2000 m^3/d for producers and (2) 5000 m^3/d for injectors. If the value is higher than field management rules, a new pair composed by maximum possible flow rate along with corresponding bottom-hole pressure replaces calculated operating point.

As a general restriction, just one variable is allowed to be imposed in the reservoir simulator as fixed constraint for the entire coupling interval. In this work, due to simulator limitations in explicit couplings, the operating point flow rate (q_{OP}) (PID manipulated variable) is the term that must be imposed, number 4 in Figure 4.4. Therefore, in order to lead the process to match the correct behavior, operating point bottom-hole pressure (BHP_{OP}) is defined as the PID controller set point (SP), number 1 in Figure 4.4, and well bottom-hole pressure calculated by reservoir simulator (BHP_{RS}) is taken as measured variable [$y(t)$], depicted as number 5 in figure 4.4.

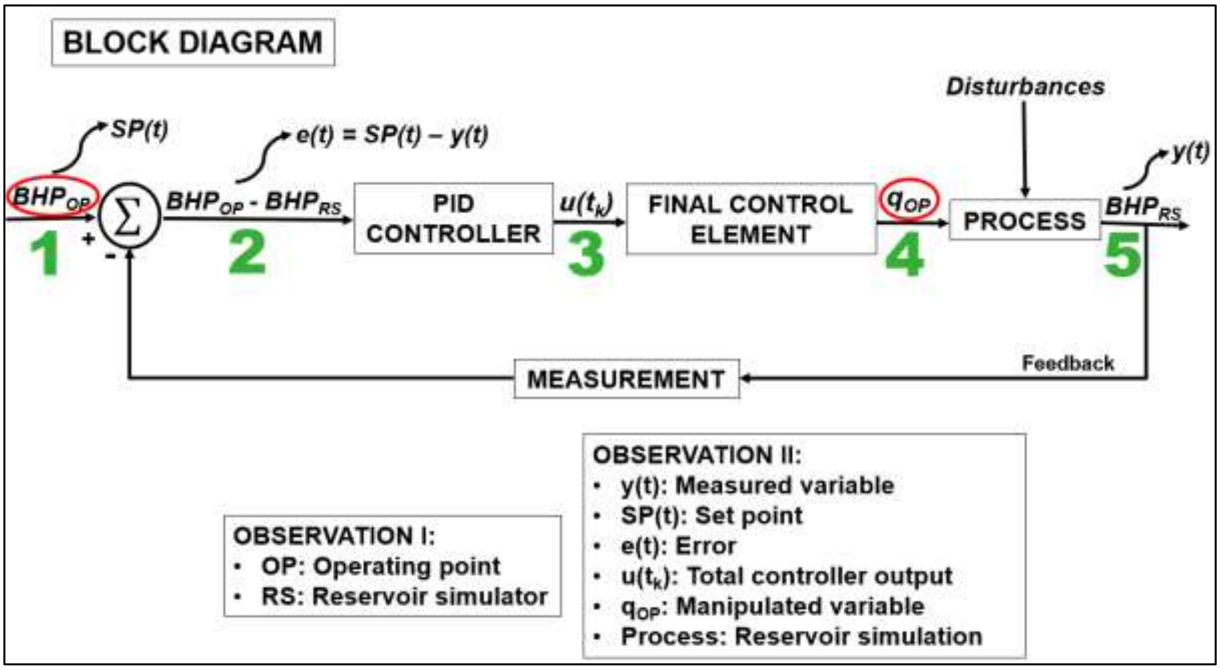

Figure 4.4: PID controller block diagram of the methodology implemented to minimize oscillation problems of subsurface-surface explicit coupling of UNISIM-I-D benchmark.

At the end of coupling interval, the well flow rate (q_{RS}) is equal to q_{OP} and the difference between set point and measured variable is the error [$e(t)$] (Equation 4.1), number 2 in Figure 4.4.

$$e(t) = SP - y(t) = BHP_{OP} - BHP_{RS} \qquad \textbf{Equation 4.1}$$

At the beginning of next time step, $e(t)$ is the input to the PID controller algorithm as in Equation 2.12 (discrete velocity). The PID controller output [$u(t_k)$], shown as the number

3 in Figure 4.4, is used by the coupling program in the final control element stage of the PID block diagram to calculate an estimation of a stable pressure (P_{Stable}). This pressure needs to correct the IPR curve received from the reservoir simulator in such a way that the new IPR curve can be used to determine a proper operating point for the next entire coupling interval. Equations 4.2 and 4.3 are used to calculate the estimation of P_{Stable} for producer and injector wells respectively.

$$P_{Stable} = P_{Block}[1 + ABS(u(t_k))] \quad -1 \le u(t_k) \le 1 \qquad \textbf{Equation 4.2}$$

$$P_{Stable} = P_{Block}[1 - ABS(u(t_k))] \quad -1 \le u(t_k) \le 1 \qquad \textbf{Equation 4.3}$$

Figures 4.5 and 4.6 depict likely pressure profiles of producer and injector wells respectively, when grid block area of reservoir simulation model is smaller than well drainage area. It can be seen that drainage pressure ($\bar{P}$) is: (1) greater than well block pressure in producer wells and (2) lower than well block pressure in injector wells. Therefore, since Equations 4.2 and 4.3 are defined based on absolute value of $u(t_k)$, the calculated P_{Stable} can possibly be considered an estimation of $\bar{P}$.

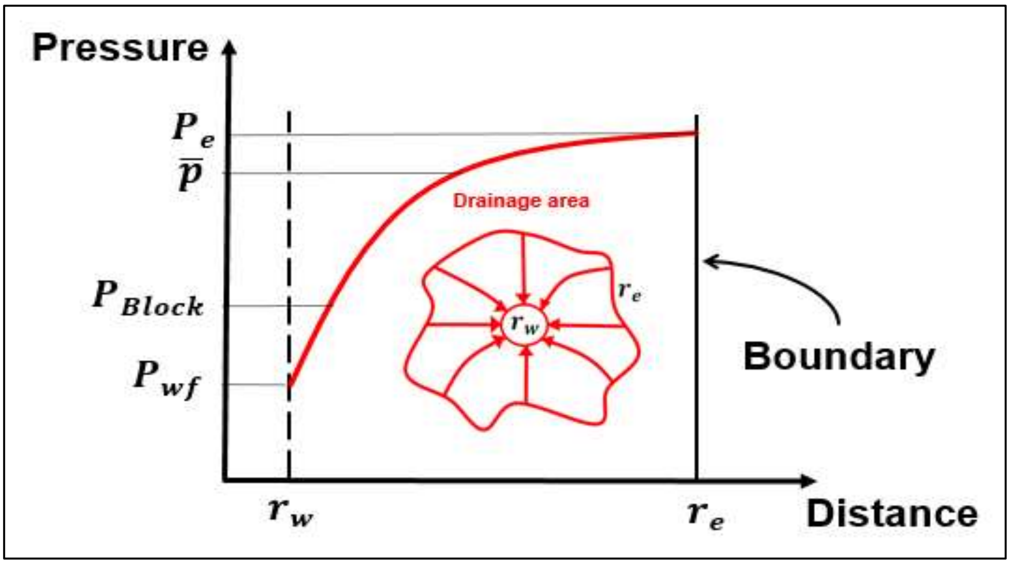

Figure 4.5: Pressure distribution in drainage area of producer well.

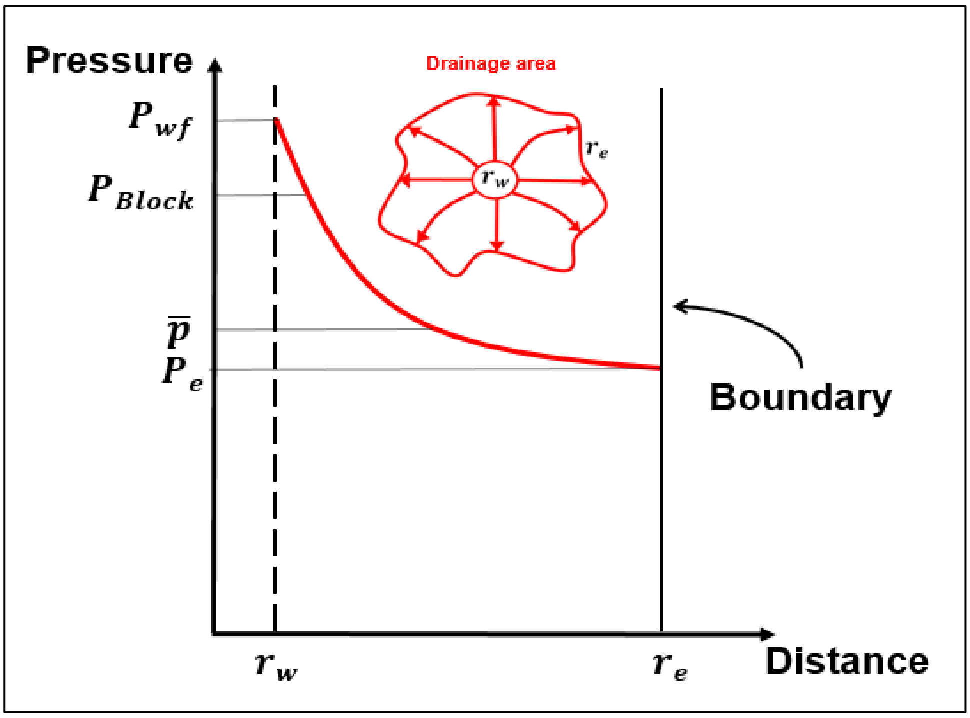

Figure 4.6: Pressure distribution in drainage area of injector well.

In the next step, applying P_{Stable}, the IPR curve generated by reservoir simulator is corrected changing its linear and angular coefficients. Both modifications are a consequence of the replacement of P_{Block} per P_{Stable} in the IPR curve.

The process described above can be seen with more details in Figures 4.7 and 4.8 (final control element) for injector and producer wells respectively. Both figures present three main elements: equation used to calculate an estimation of stable pressure, modification of linear and angular coefficients of IPR curve, and the final test to verify if calculated operating point obey maximum system requirements.

In summary, at each time step, the PID controller receives one input $[e(t)]$, and generates one output $[u(t_k)]$ that is used to correct the traditional IPR curve generated by reservoir simulator. This correction is finally addressed by the coupling program, which uses the corrected IPR curve to calculate a new operating point. This whole process is repeated until the end of simulation time span.

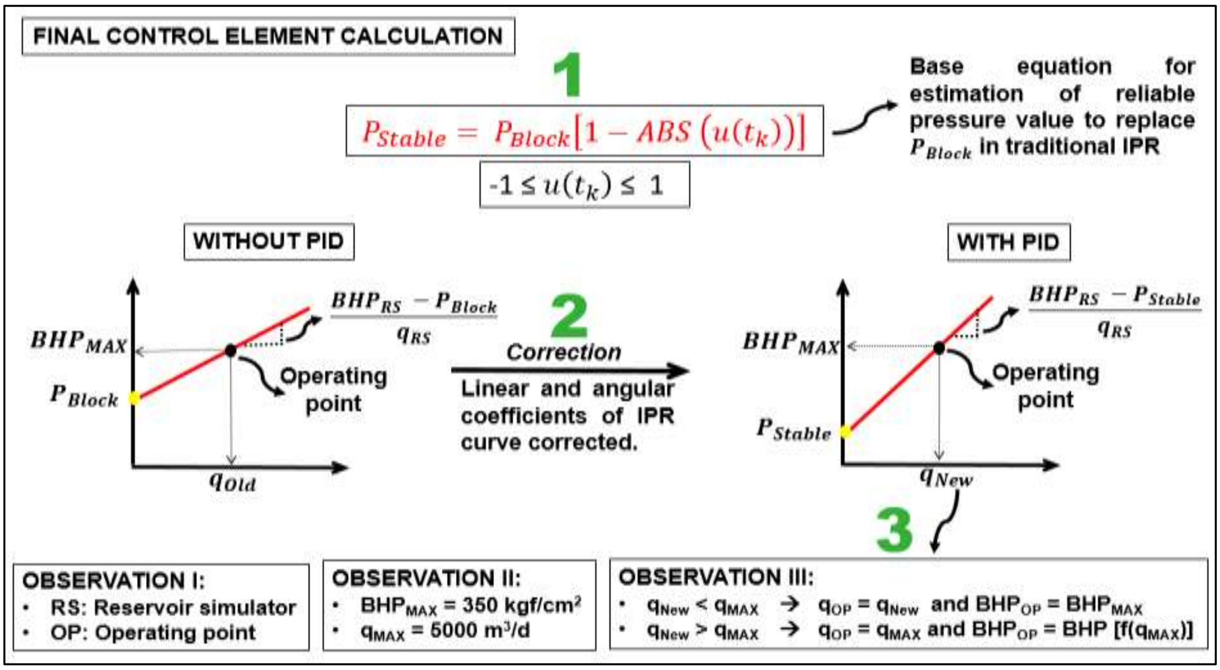

Figure 4.7: Schematic procedure of injector well IPR correction and calculation of new operating point.

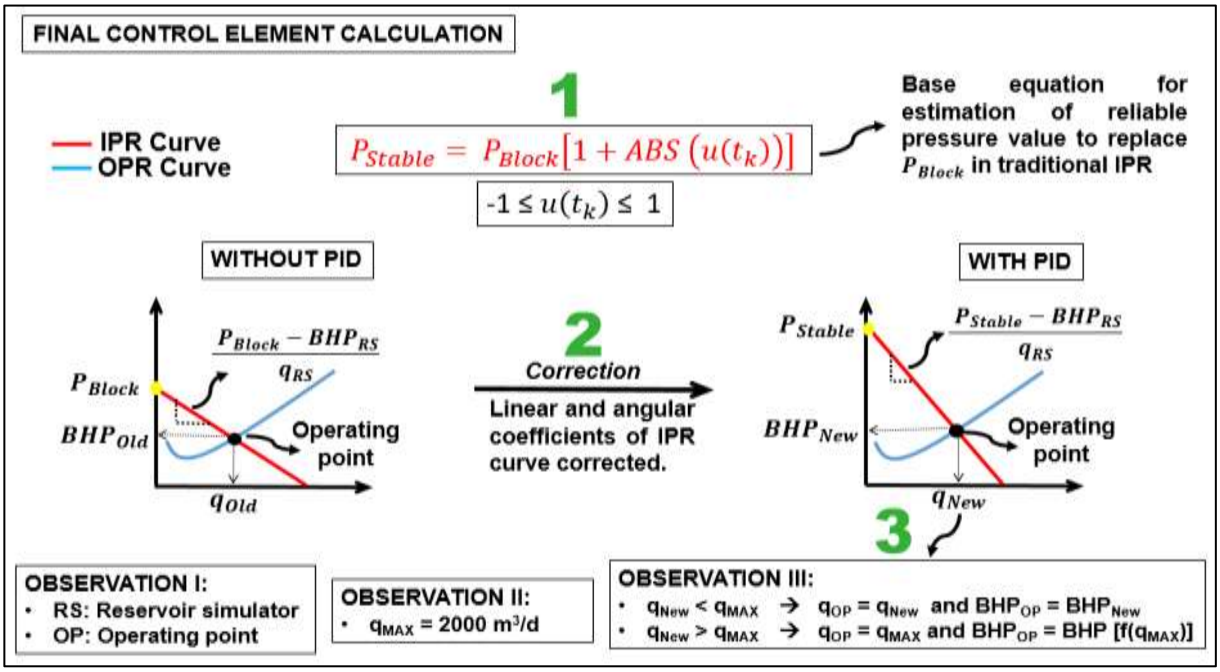

Figure 4.8: Schematic procedure of producer well IPR correction and calculation of new operating point.

5 APPLICATION

This chapter is dedicated to describe the case study and to present data available for the work.

5.1 Description of reservoir model

The proposed methodology is applied to the UNISIM-I-D benchmark (Avansi & Schiozer, 2015), which is based on Namorado Field, located offshore Brazil in Campos Basin (Table 5.1). The simulation model has a grid block defined as 100x100x8m discretized into a corner point grid with a total of 81x58x20 cells, of which 36,739 are active (Figure 5.1). The case has 1461 days initial history production of 4 vertical wells (NA1A, NA2, NA3D and RJS19) starting on 31st May 2013, and exploitation strategy is defined until 31st May 2043.

Table 5.1: Reservoir data.

Reservoir data	Value	Units
Depth	2900-3400	m
Water depth	166	m
Coastline distance	80	km
Water temperature	20 to 16 linear (downhill)	ºC
Sea current	0.5	m/s

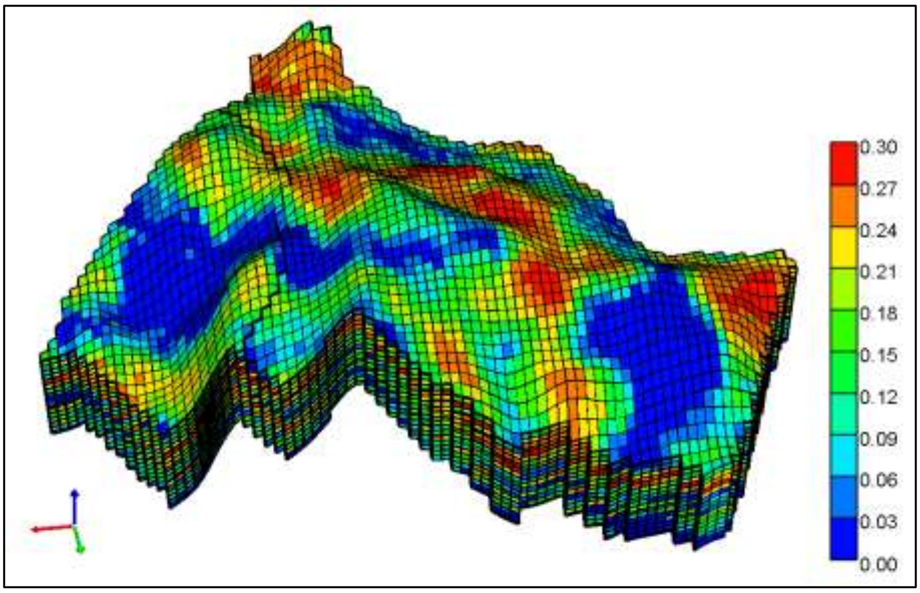

Figure 5.1: Porosity map of UNISIM-I-D benchmark (view [degrees] Æ Longitude: -164.2; Latitude: 43.2).

The reservoir is composed mainly by sandstone of turbiditic origin, with a sealing fault dividing the model in two regions: east and west blocks (Avansi, 2014) (Figure 5.2). A summary of model volumes can be seen in Table 5.2.

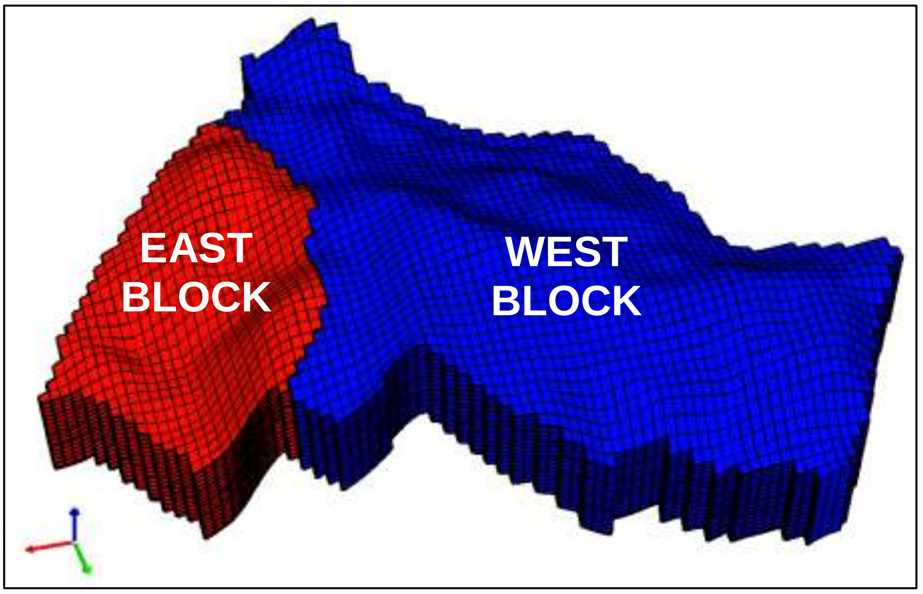

Figure 5.2: Schematic showing two regions of UNISIM-I-D benchmark (view [degrees] Æ Longitude: -164.2; Latitude: 43.2).

Table 5.2: Volumes of UNISIM-I-D benchmark.

Term	**Total volume**	**Units**
Block	$29.15*10^8$	m^3
Pore	$3.01*10^8$	m^3
Oil in place at standard conditions	$136.77*10^6$	m^3

At initial conditions: (1) water-oil contacts of east and west blocks are 3224m and 3100m respectively, and (2) reference pressure is 327 kgf/cm^2 at 3000m.

In this application, a Black oil model is used to describe reservoir fluids. At reservoir temperature (80 ºC), bubble point pressure is 210.03 kgf/cm^2, oil compressibility is $1.62*10^{-4}$ $1/(kgf/cm^2)$ and PVT data is present in Table 5.3.

The case study has a water wet reservoir with rock compressibility of 82.4 $*10^{-6}$ $1/(kgf/cm^2)$. Rock-fluid interaction properties can be seen in Tables 5.5 and 5.6 for water-oil and liquid-gas systems respectively.

Table 5.3: PVT data at 80 ºC.

Pressure (kgf/cm^2)	Oil properties			Gas properties	
	R_S	B_o	μ_o cP	B_g	μ_g cP
35.49	31.80	1.198	2.05	0.0346	0.0109
41.82	34.66	1.200	1.99	0.0291	0.0113
49.20	38.02	1.210	1.91	0.0245	0.0117
59.75	42.83	1.230	1.81	0.0199	0.0123
68.54	46.85	1.240	1.73	0.0172	0.0128
80.85	52.51	1.250	1.62	0.0144	0.0134
93.86	58.51	1.270	1.52	0.0123	0.0142
105.81	64.06	1.280	1.43	0.0108	0.0148
121.98	71.60	1.300	1.32	0.0093	0.0157
133.94	77.20	1.320	1.25	0.0084	0.0164
148.00	83.83	1.330	1.17	0.0076	0.0172
166.29	92.49	1.350	1.09	0.0067	0.0182
193.36	105.42	1.390	1.00	0.0058	0.0197
213.26	115.01	1.410	0.96	0.0053	0.0208
219.38	117.64	1.420	0.94	0.0051	0.0211
229.50	122.19	1.430	0.91	0.0049	0.0217
248.00	130.84	1.450	0.85	0.0045	0.0227
283.02	147.22	1.500	0.75	0.0040	0.0246
316.91	163.08	1.540	0.65	0.0035	0.0265
352.63	179.79	1.580	0.54	0.0032	0.0285
360.00	183.24	1.590	0.52	0.0031	0.0289

Water properties are present in Table 5.4.

Table 5.4: Water properties.

B_w	μ_w cP	c_w $1/(kgf/cm^2)$
1.021	0.3	$47.64*10^{-6}$

Table 5.5: Water-oil relative permeability and capillary pressure.

S_w	K_{rw}	K_{row}	P_{cow} (kgf/cm^2)
0.17	0.00	0.58	0.54
0.20	0.00	0.51	0.35
0.25	0.00	0.41	0.19
0.30	0.00	0.32	0.12
0.35	0.00	0.24	0.08
0.40	0.00	0.18	0.05
0.45	0.01	0.13	0.04
0.50	0.01	0.09	0.03
0.55	0.02	0.05	0.02
0.60	0.04	0.03	0.02

0.65	0.05	0.02	0.01
0.70	0.07	0.01	0.01
0.75	0.10	0.00	0.01
0.79	0.13	0.00	0.01
0.82	0.15	0.00	0.01

Table 5.6: Liquid-gas relative permeability.

S_g	K_{rg}	K_{rog}
0.0	0.000	0.58
0.18	0.002	0.387
0.20	0.003	0.309
0.25	0.006	0.203
0.30	0.010	0.143
0.35	0.017	0.102
0.40	0.026	0.072
0.45	0.037	0.050
0.50	0.052	0.034
0.55	0.070	0.021
0.60	0.093	0.014
0.65	0.119	0.006
0.70	0.150	0.000

5.2 Description of exploitation strategy

The exploitation strategy E9 was optimized by Schiozer et al. (2015) based on the standalone simulation model of UNISIM-I-D benchmark, which was developed applying the 12 steps methodology from the same authors. It has water flooding as secondary recovery method and is composed by 20 wells (Figure 5.3). From history production, wells NA2, NA3D and RJS19 were closed and IL_NA1A kept opened during forecast stage. More details are present in Table 5.7.

The exploitation strategy considered in this work, called base strategy, is a particular case of E9 strategy (standalone model) with altered producer well boundary conditions. The operating conditions of producer and injector wells of base strategy are present in Table 5.8. These additional restrictions represent system limits imposed by the management rules of the field. They need to be checked out at each time step by coupling program during the integration of subsurface and surface systems.

Table 5.7: Details of exploitation strategy E9.

Term	Value	Units
Vertical well producers	3	---

Horizontal well producers	10	---
Horizontal well injectors	7	---
Platform max liquid production	20,150	m^3/d
Platform max oil production	20,150	m^3/d
Platform max water production	9,765	m^3/d
Platform max water injection	28,210	m^3/d

Table 5.8: Well operating additional constraints to be checked by the coupling program.

	Injectors	**Producers**	**Units**
Fluid	MAX STW: 5000	MAX STL: 2000	m^3/d
Pressure	MAX BHP: 350	MIN WHP: 15	kgf/cm^2

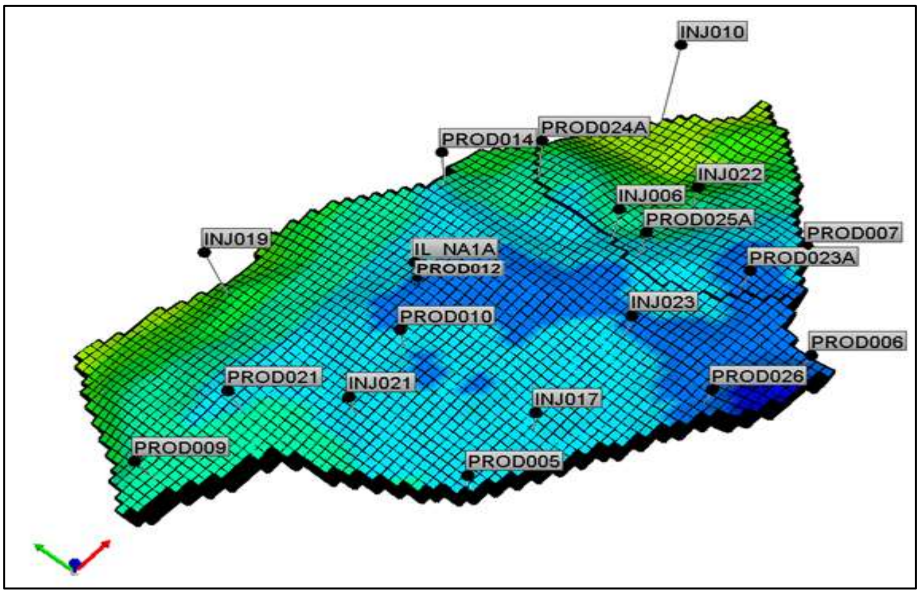

Figure 5.3: Producer and injector wells location of UNISIM-I-D benchmark exploitation strategy (view [degrees] Æ Longitude: -306.7; Latitude: 74.7).

5.3 Description of production system

The production system considered in this work is comprised by satellite wells (Figure 5.4) with 166m of water depth, which connect the bottom-hole to the separator on the platform of UNISIM-I-D benchmark. Production column, flowlines and riser compose these satellite wells (Figure 5.5).

The geometric factors (pipe diameters) adopted to all wells on UNISIM-I-D benchmark (Table 5.9) were optimized by Victorino et al. (2016), which were selected considering net present value as the objective function.

To generate the OPR (Outflow Performance Relationship) curves for producer wells, the following information for Black oil model were the input of the production system simulator:

1) Oil, gas and water specific gravities (Table 5.10);
2) Pipe diameter (Table 5.9), length (Table 5.11) and relative roughness (0.0006);
3) Reservoir and separator temperatures (Table 5.12) with vertical linear thermal gradient;
4) Liquid rate (q_l), gas/liquid ratio (GLR) and water cut ($WCUT$);
5) Well-head pressure (WHP).

The following correlations were selected to be used in the production system simulator calculations: Standing (1947) for oil formation volume factor (B_O), Lasater (1958) for oil bubble point pressure (P_B) and solution gas oil ratio (R_S), and Beggs & Brill (1973) for pressure drop.

Table 5.9: Geometric factors of UNISIM-I-D satellite wells.

Pipe segment	**Diameter**	**Units**
Production Column	5	in
Flowline	6	in
Riser	6	in

Table 5.10: Fluid specific gravities.

Fluid	**Specific gravity**
Oil	0.87
Gas	0.74
Water	1.01

Table 5.11: Length of pipe segment.

Well	**Production column**	**Flowline**	**Riser**	**Units**
PROD005	2834.6	2519.8	166	m
PROD006	2772.6	2733.7	166	m
PROD007	2809.9	2454.9	166	m
PROD009	2867.1	4127.3	166	m
PROD010	2811.2	1424.1	166	m
PROD012	2789.3	983.9	166	m
PROD014	2855.8	1297.4	166	m
PROD021	2852.1	3048.1	166	m
PROD023A	2790.8	1986.1	166	m
PROD024A	2870.4	1192.9	166	m

PROD025A	2816.3	1073.7	166	m
PROD026	2787.7	2229.4	166	m
IL_NA1A	2795.9	1044.7	166	m

Table 5.12: System temperatures.

Term	Temperature	Units
Separator	20	ºC
Reservoir	80	ºC

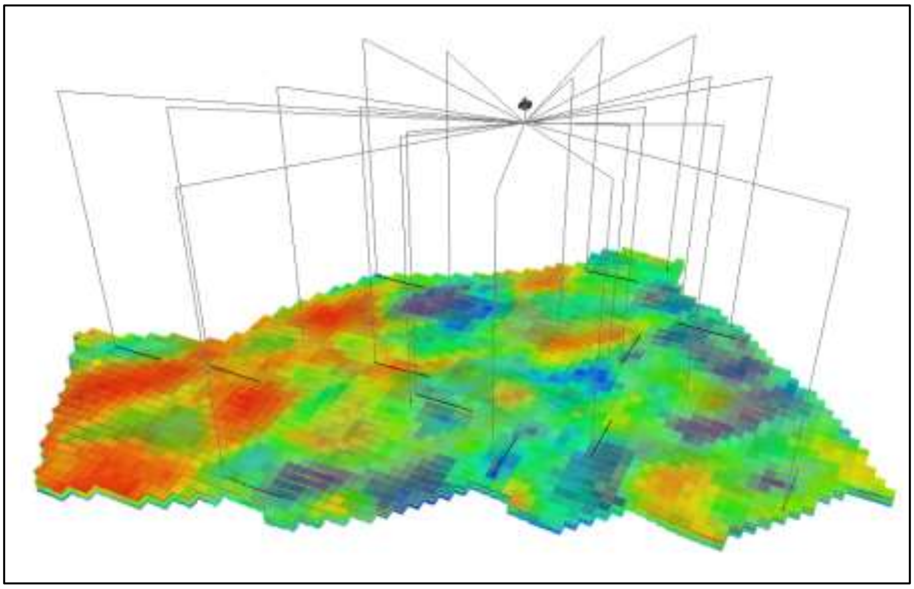

Figure 5.4: UNISIM-I-D benchmark production system – satellite wells connecting bottom-hole to separator on the platform (Hohendorff Filho et al., 2016).

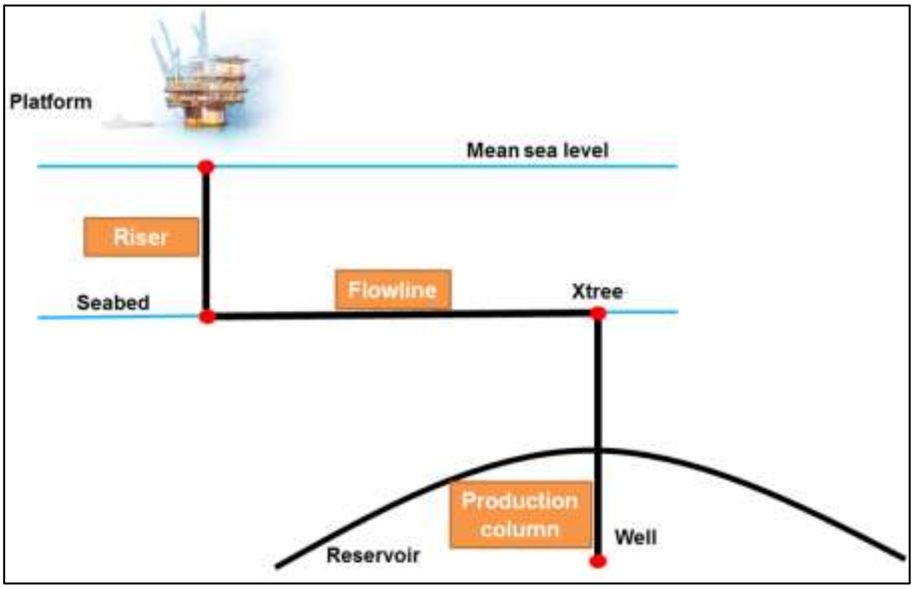

Figure 5.5: Satellite well template composed by production column, flowline and riser.

5.4 Description of software used

This work was performed considering an adaptive time step varying between 2 to 31 days and applying 3 software:

1) A reservoir simulator to evaluate fluid flow in porous media;
2) A production system simulator to investigate fluid flow in the artificial structures (production column, flowline and riser) and estimate pressure drop;
3) An in-house coupling program to manage the process of data exchange between simulators.

5.5 Description of explicit coupling instabilities

In this work, the network and reservoir systems of UNISIM-I-D benchmark are coupled explicitly at the bottom-hole level using time step lagged balancing frequency. The reservoir simulator used does not allow the implementation of iteratively lagged method and besides that, the application of periodic balancing frequency is not suitable in the case study since oscillations are present.

The results indicated that producer and injector wells keep opened with oscillation problems in bottom-hole pressure (BHP) and flow rate (q), or close as consequence of wrong solutions. Figure 5.6 is an example of unstable results as consequence of the explicit coupling between reservoir and production systems without a methodology to avoid instabilities.

Therefore, a new methodology based on PID controller, technique applied in engineering problems aiming to stabilize systems eliminating oscillation, is presented in order to minimize subsurface-surface explicit coupling instabilities in a simple and efficient way.

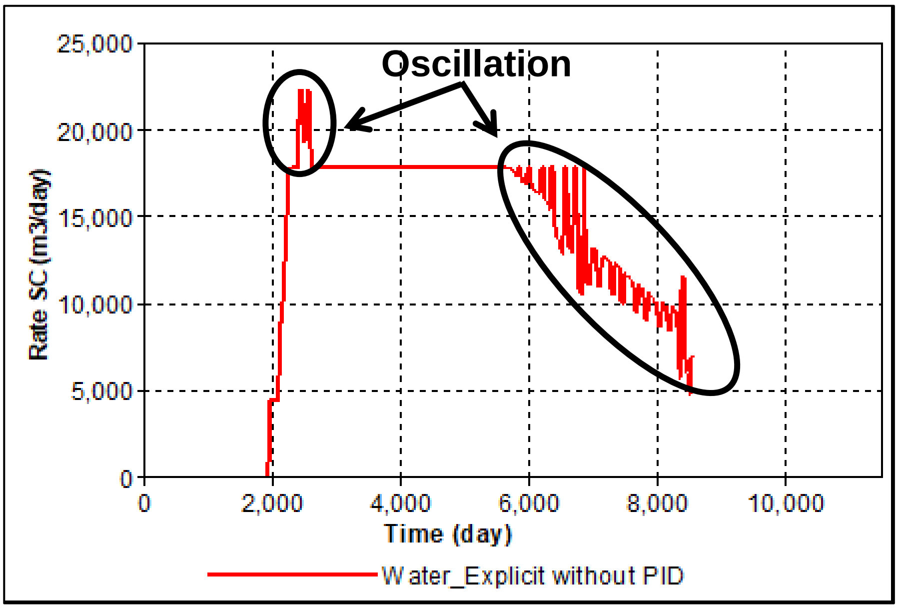

Figure 5.6: Field total water injection rate with three distinct moments: (1) peak around 2000 days due to opening and immediate closing of well INJ023, (2) plateau indicating opened injector wells (INJ006, INJ019, INJ021 and INJ022) working at maximum limit and (3) continuous oscillatory reduction of rate because injector wells started to operate oscillating bellow maximum limit.

6 RESULTS AND DISCUSSIONS

This chapter is dedicated to present the main results and discussions of this work.

6.1 Impact of new methodology implementation

Explicit coupling between reservoir and production systems of UNISIM-I-D benchmark without PID controller caused instabilities in 3 producer wells (PROD 010, PROD 025A, PROD 026) and 7 injector wells (INJ 006, INJ 010, INJ 017, INJ 019, INJ 021, INJ 022, INJ 023). These wells either closed or kept opened with BHP and flow rate oscillating. This is indeed, depicted for injector wells in Figures 6.1 and 6.2, whereby water rate and BHP unstable results are shown respectively. All 7 injector wells operated in this field have both variables highly affected when explicit coupling is implemented without a mechanism to avoid oscillations.

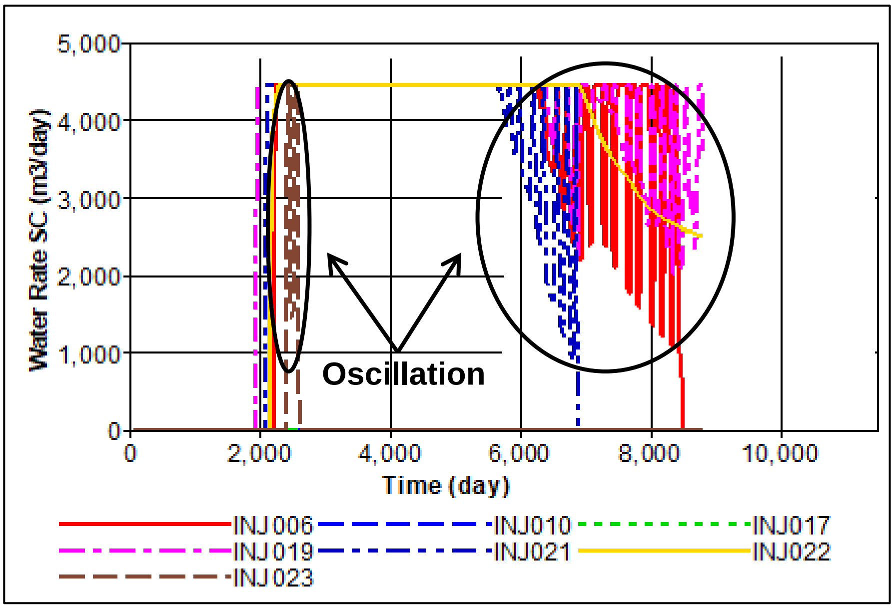

Figure 6.1: Water rate of injector wells – explicit coupling without PID controllers.

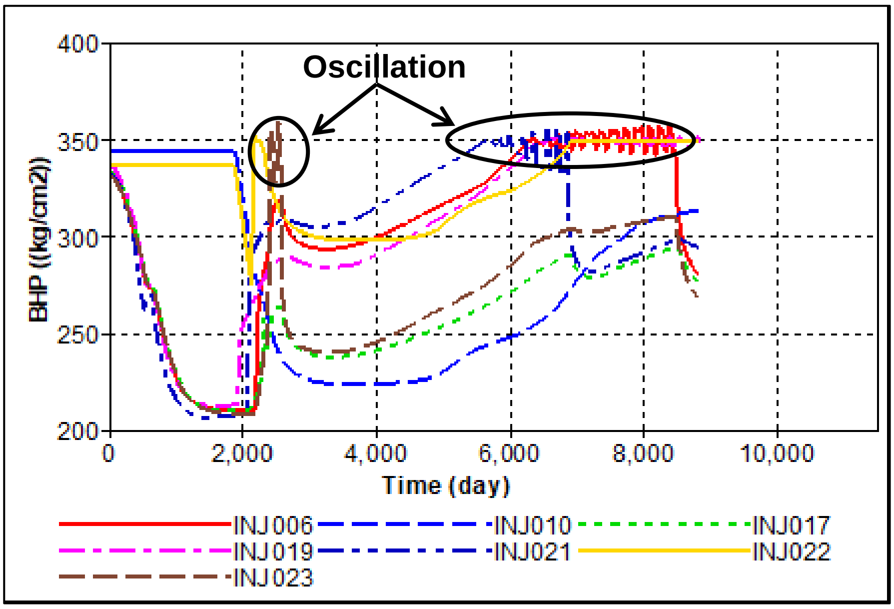

Figure 6.2: BHP of injector wells – explicit coupling without PID controllers.

Figures 6.3 and 6.4 present, respectively, oil rate and BHP instabilities in producer wells. In this case, 3 from a total of 13 producers, have both variables affected when subsurface-surface systems are integrated by the explicit coupling without a technique to control the oscillations. Therefore, in this case study results indicate that producers are more stable than injectors in terms of oscillatory behavior.

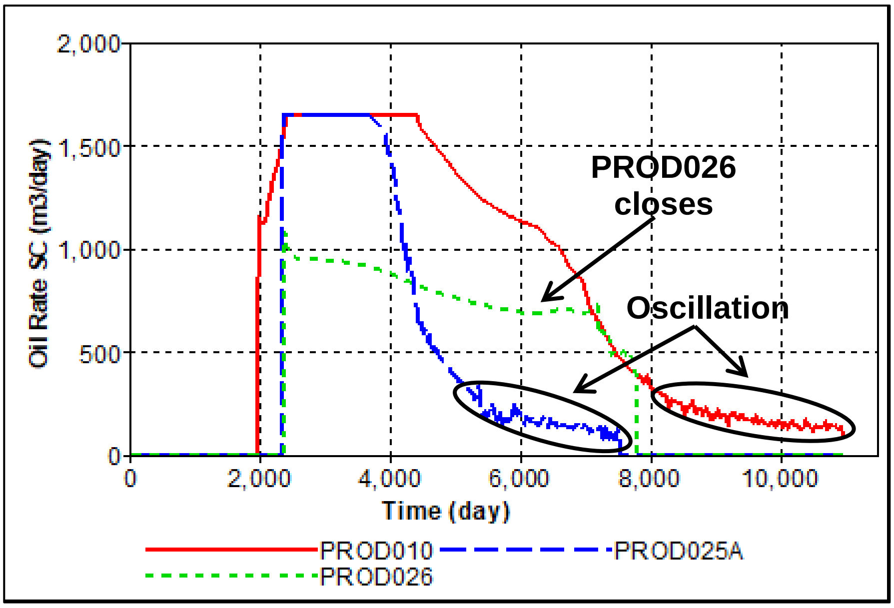

Figure 6.3: Oil rate of producer wells – explicit coupling without PID controllers.

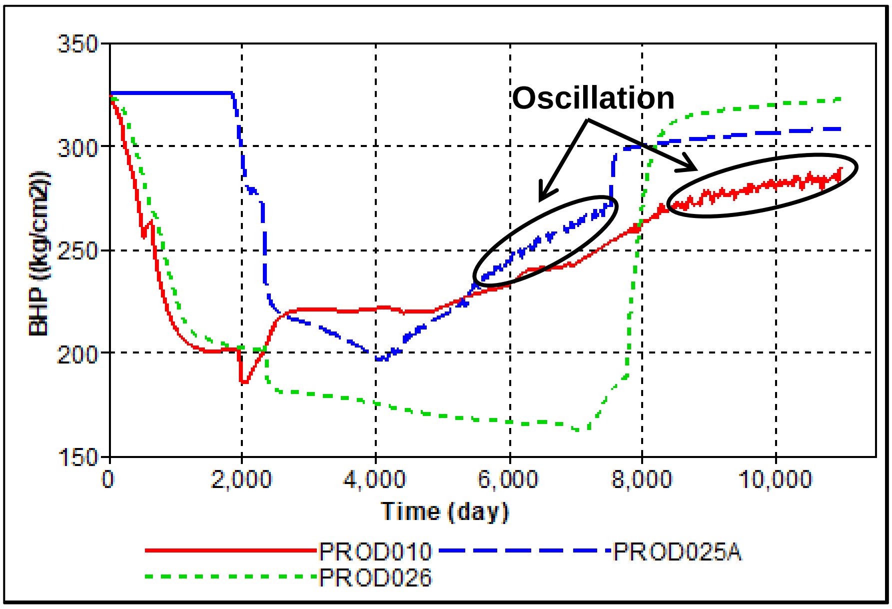

Figure 6.4: BHP of producer wells – explicit coupling without PID controllers.

To minimize the instabilities, a new methodology based on control engineering was developed. In particular, a new framework using PID controllers was employed. Two global PID controllers, manually tuned, were implemented in the case study: one for the group of 7 injectors and another for the group of 3 producers.

The definition of set point, measured and manipulated variables, PID controller design, is a primordial process task. In the first test, based on steady behavior of well block pressure derivative ($\frac{\partial P_{Block}}{\partial t}$) in the results of decoupled method, absolute value of $\frac{\partial P_{Block}}{\partial t}$ at the beginning of time step was selected as set point and consequently absolute value of $\frac{\partial P_{Block}}{\partial t}$ at the end of time step was defined as measured variable.

In this method, the traditional IPR curve generated by reservoir simulator wasn't corrected using the PID controller output $[u(t_k)]$, instead, this curve was applied directly in the calculation of operating point. Following well deliverability determination, the obtained flow rate was adjusted using $u(t_k)$. Thus, the new flow rate was selected as manipulated variable.

The formulation employing these three terms in the PID controller framework didn't work properly as expected.

A different test was done using the idea presented before in the methodology chapter. Since results were satisfactory and new approach has potential to be implemented in a variety of scenarios, it was implemented in the case study.

When it comes to the values of constants (K_C, τ_I, τ_D), there are many combinations capable of minimizing the oscillatory behavior of the explicitly coupled subsurface-surface systems. To make the tuning process as fast and efficient as possible, just one set of PID parameters was selected for the two global PID controllers (single tuning approach), eliminating the necessity of a well by well tuning. In this case, $K_C = 0.00095$, $\tau_I = 8.7$and $\tau_D = 6.5$ were chosen as ideal constant values.

Figures 6.5 and 6.6 show respectively water rate and BHP of injector wells after application of tuned PID controllers. They indicate that both variables are controlled without presence of oscillation after application of the new technique.

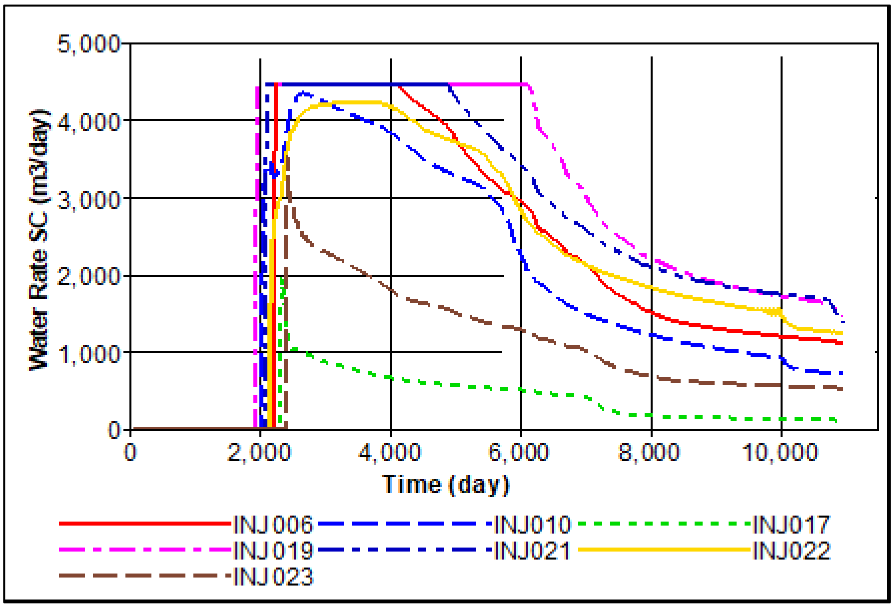

Figure 6.5: Water rate of injector wells – explicit coupling with PID controllers.

Figures 6.7 and 6.8 show respectively oil rate and BHP of producer wells after application of tuned PID controllers. They indicate that both variables are controlled with no oscillation after application of the new technique.

All of these results show a promising application of PID control framework to reduce pressure and rate oscillations as expected by a more theoretical point of view. Although not studied in depth in this project, many of the performance checks for the PID controller arrangement can be explored for an enhanced stability and behavior analysis. This can involve a study of PID controller step responses characteristics such as rise time, settling time and overshoot depicted in Figure 2.12.

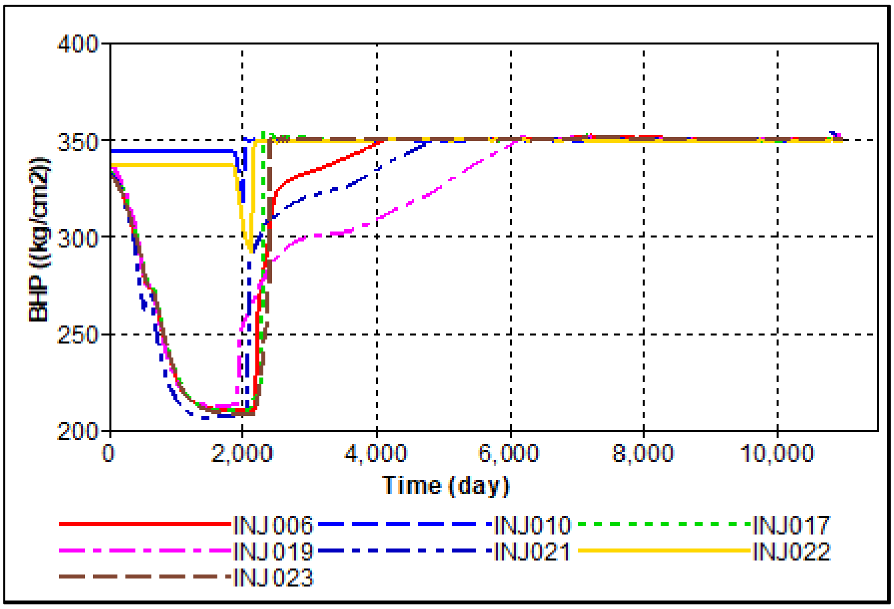

Figure 6.6: BHP of injector wells – explicit coupling with PID controllers.

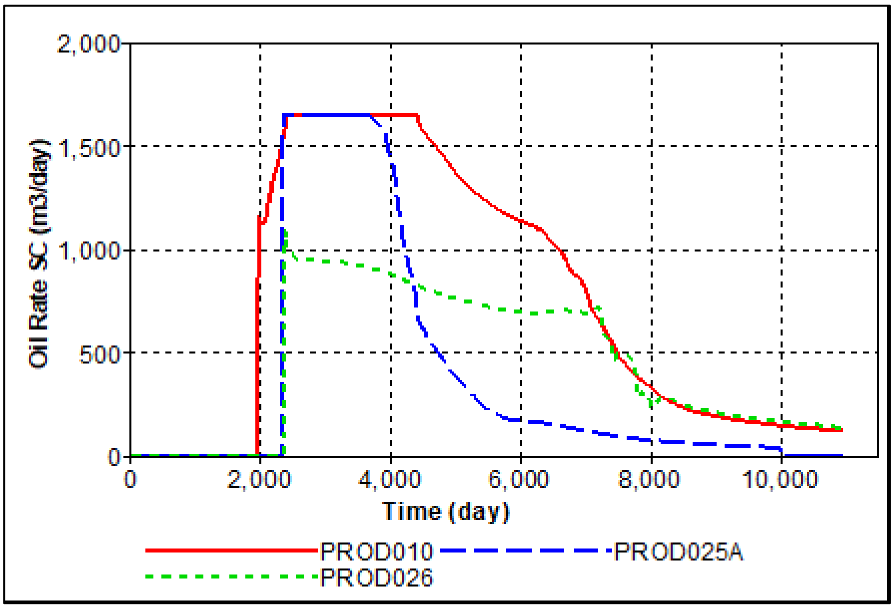

Figure 6.7: Oil rate of producer wells – explicit coupling with PID controllers.

Besides oscillation mitigation, the proposed formulation offers advantages in terms of computational efforts. The application of PID controllers allows reduction of error propagation in the solutions, reflecting in lower simulation time compared to the case that controllers are not used (Table 6.1). In addition, it is in essence a non-intrusive technique, and thus do not require access to any reservoir simulator internal code.

Since decoupled method doesn't require data exchange between simulators as explicit coupling, in this project simulation time of the first is typically 50% to 100% of the second with PID controllers considering both cases with the same time step size (Table 6.1).

However, decoupled method simulation time does not include the time allotted to prepare pressure drop tables, therefore it does not reflect the total time necessary to perform the complete process.

Besides that, maximum time step size was lowered from 31 to 1 day for decoupled method in order to reduce numerical convergence errors in the results. Consequently, simulation time has increased (Table 6.1).

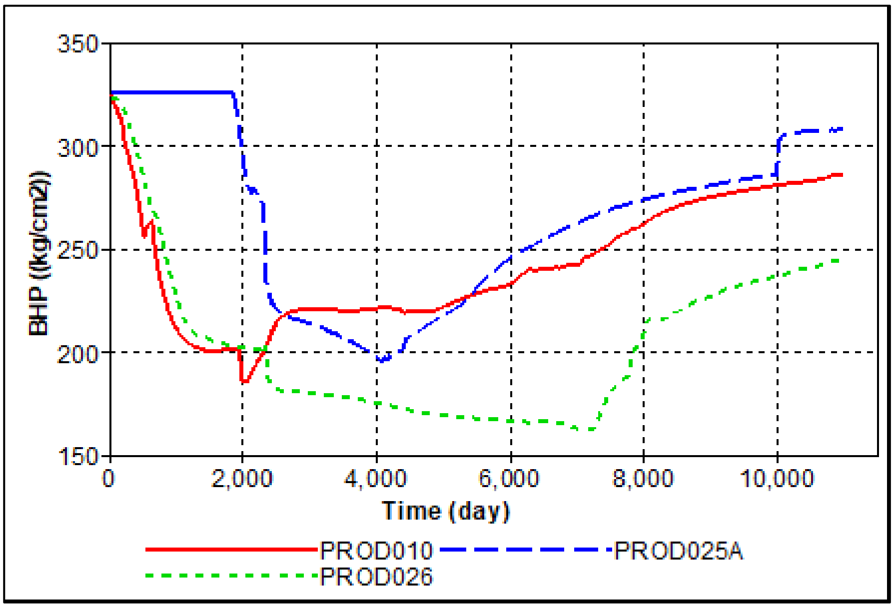

Figure 6.8: BHP of producer wells – explicit coupling with PID controllers.

Table 6.1: Example of simulation run time for one case tested.

Method	Time	Units
Explicit without PID controllers (31 days max time step)	1932	Seconds
Explicit with PID controllers (31 days max time step)	1207	Seconds
Decoupled (31 days max time step)	772	Seconds
Decoupled (1 day max time step)	1913	Seconds

6.2 Performance evaluation of new methodology

In order to check the effectiveness of new approach based on PID controllers, its results were compared with decoupled method (base case).

Locally, BHP and flow rate of injector wells (INJ 006, INJ 010, INJ 017, INJ 019, INJ 021, INJ 022, INJ 023) and producer wells (PROD 010, PROD 025A, PROD 026) in both cases are very similar. Figures are present in Appendix A.

Globally, total water injection rate and total oil production rate are also very similar in both cases as depicted in Figure 6.9.

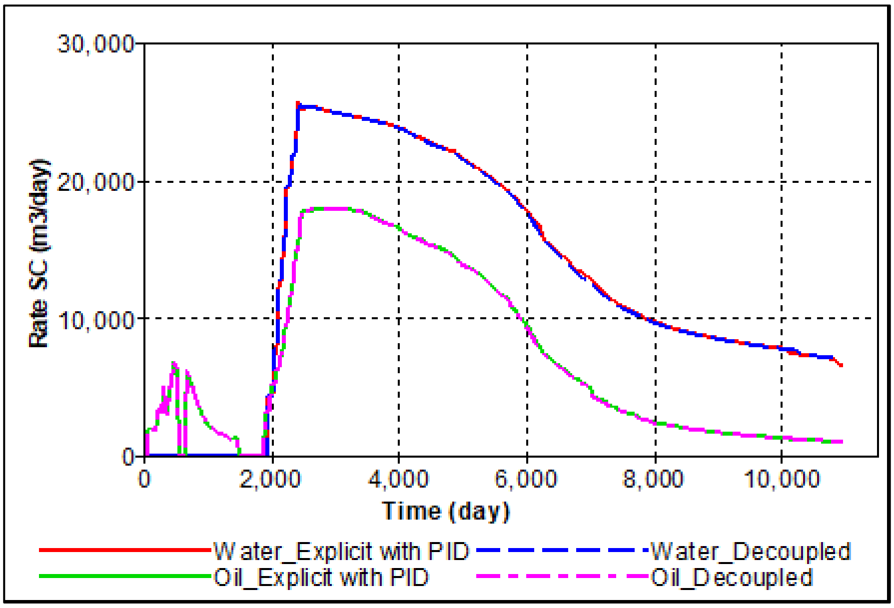

Figure 6.9: Comparison of field total water injection rate and total oil production rate in two cases: explicit with PID controllers and decoupled method.

Local and global analysis demonstrate that the performance of new technique is adequate, achieving consistent and expected results in the case study.

6.3 PID parameters sensitivity analysis

In order to check the robustness of the method, a sensitivity analysis study was performed with PID parameters in two scenarios: without and with step change in PID set point value. Well INJ 023 was selected for the test and constants K_C, τ_I and τ_D were allowed to vary only in this well.

6.3.1 Study without step change in set point

In this case, controller structure was implemented in two different forms: Proportional (P) and Proportional-Derivative (PD).

Initially, the P only controller was implemented ($\tau_I = \infty$ and $\tau_D = 0$) and parameter K_C varied. Results obtained when $K_C = 0.015$, $K_C = 0.05$ of and $K_C = 0.075$ were applyied to the coupled system, can be seen in Figures 6.10, 6.11 and 6.12 respectively.

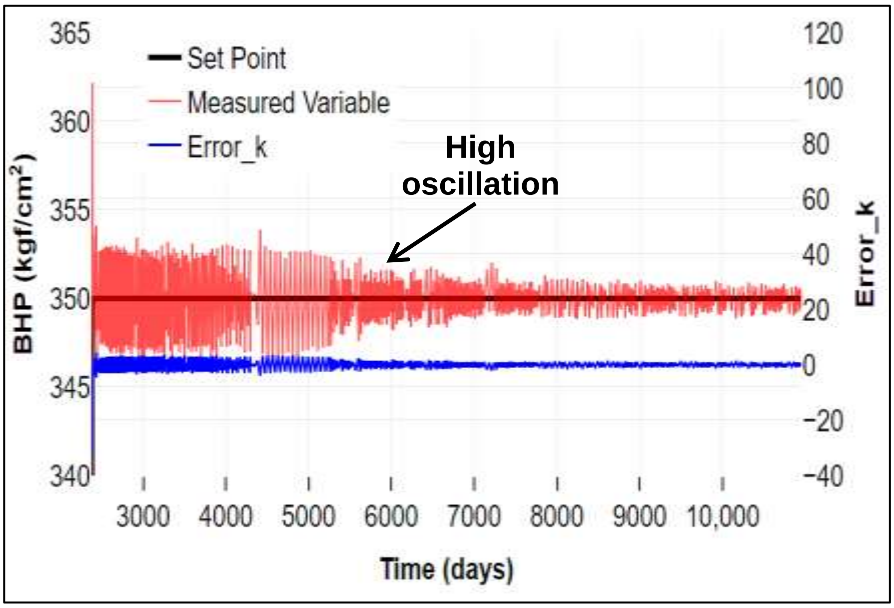

Figure 6.10: Well INJ 023 with P only controller ($\boldsymbol{K_C = 0.015}, \tau_I = \infty$ and $\tau_D = 0$).

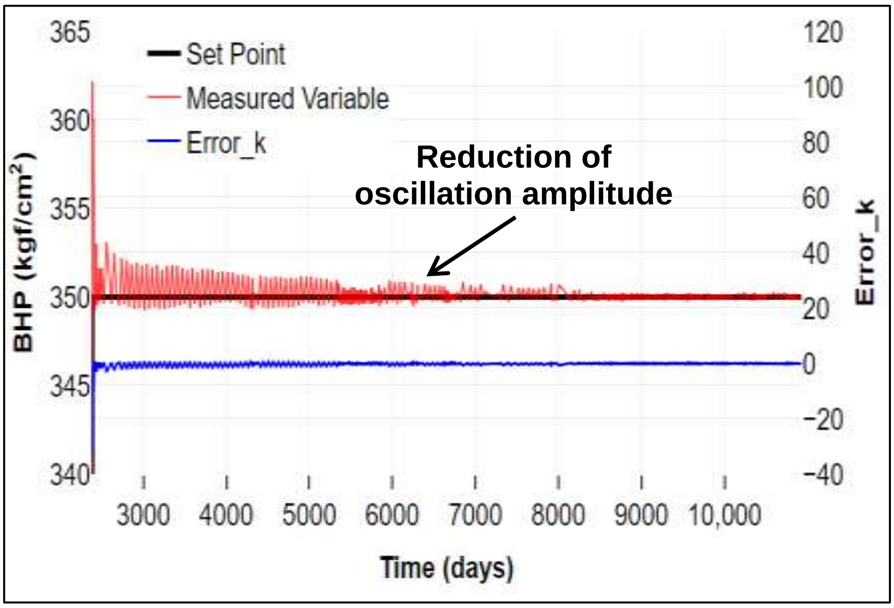

Figure 6.11: Well INJ 023 with P only controller ($\boldsymbol{K_C = 0.05}, \tau_I = \infty$ and $\tau_D = 0$).

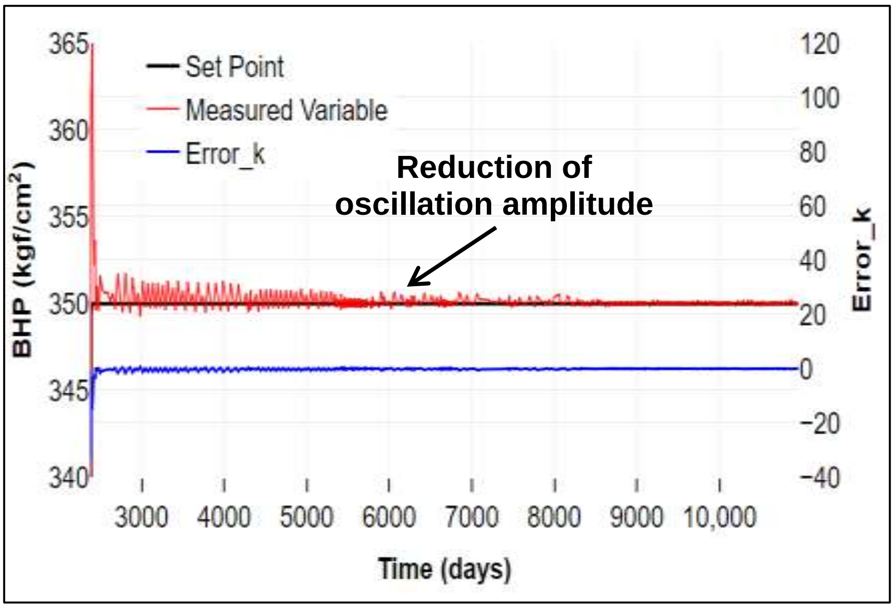

Figure 6.12: Well INJ 023 with P only controller ($\boldsymbol{K_C = 0.075}, \tau_I = \infty$ and $\tau_D = 0$).

Oscillation amplitude was reduced by the increase of K_C value, however the P only controller was not capable of eliminating completely this non-physical fluctuation. Besides that, if the proportional parameter is increased to greater values, measured variable can deviate from the correct response resulting in system entire instability.

Since the steady-state error was not clearly identified, the integral term was not applied in the controller, because its main function is to cancel the effect of this issue. Therefore, in the next step, PD controller was implemented ($\tau_I = \infty$) and parameter τ_D varied while K_C was fixed. Figures 6.13 and 6.14 represent respectively, the results obtained by the application of $\tau_D = 0.2$ and $\tau_D = 0.3$ with $K_C = 0.075$.

The derivative term was efficient to reduce settling time. As a result, the proper tuning of constants K_C and τ_D of controller applied to well INJ 023 without a step change in set point value, minimized the oscillations and lead the system to stabilize with error close to zero.

Both controller parameters (K_C, τ_D) worked as expected by classical theory (Seborg et al., 2016; Akakpo & Gildin, 2017), and a summary of the effects caused by each constant in the results is presented in Table 6.2.

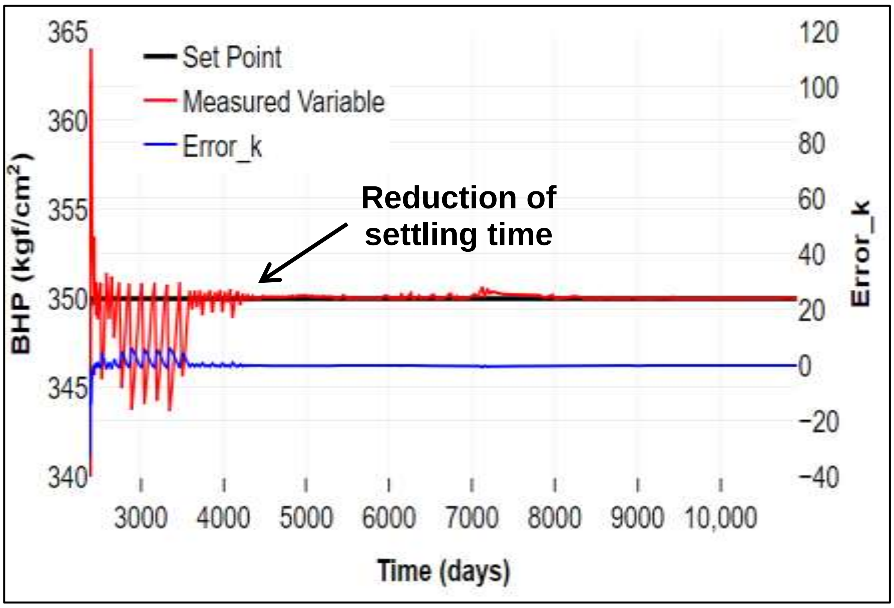

Figure 6.13: Well INJ 023 with PD controller ($K_C = 0.075, \tau_I = \infty$ and $\boldsymbol{\tau_D = 0.2}$).

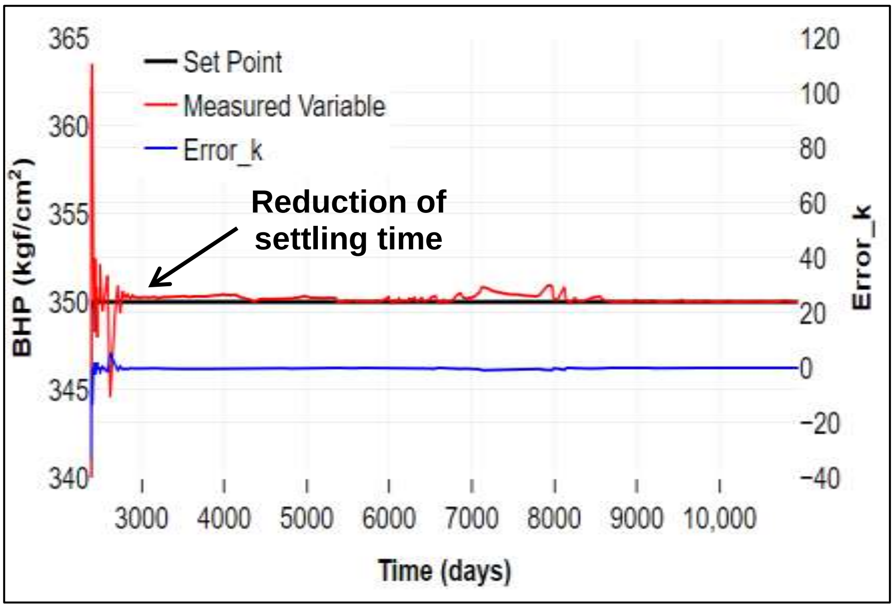

Figure 6.14: Well INJ 023 with PD controller ($K_C = 0.075, \tau_I = \infty$ and $\boldsymbol{\tau_D = 0.3}$).

Table 6.2: Effects of changing a PID parameter independently in well INJ 023 without step change in set point value.

Parameter	**Oscillation**	**Settling Time**
$\uparrow \boldsymbol{K_C}$	Amplitude reduction	$---$
$\uparrow \boldsymbol{\tau_D}$	$---$	Decrease

6.3.2 Study with step change in set point

A step change of 5 kgf/cm^2 was applied in PID set point value aiming to examine controller action in the presence of steady-state error. In this case, controller structure was implemented in three different forms: Proportional (P), Proportional-Integral (PI) and Proportional-Integral-derivative (PID).

Initially, the P only controller was implemented ($\tau_I = \infty$ and $\tau_D = 0$) and parameter K_C varied. Results obtained when $K_C = 0.005$, $K_C = 0.01$ of and $K_C = 0.05$ were applyied to the coupled system, can be seen in Figures 6.15, 6.16 and 6.17 respectively.

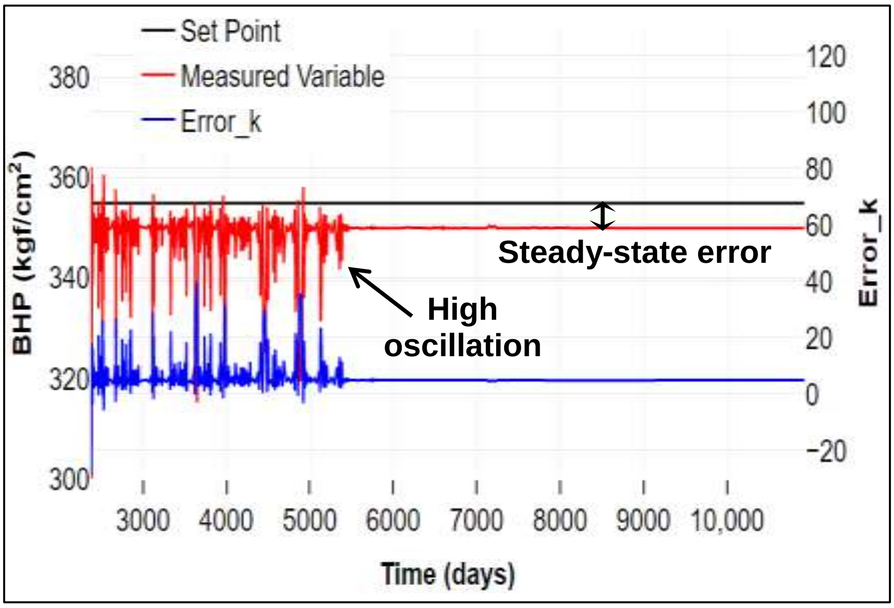

Figure 6.15: Well INJ 023 with P only controller ($\boldsymbol{K_C = 0.005}$, $\tau_I = \infty$ and $\tau_D = 0$).

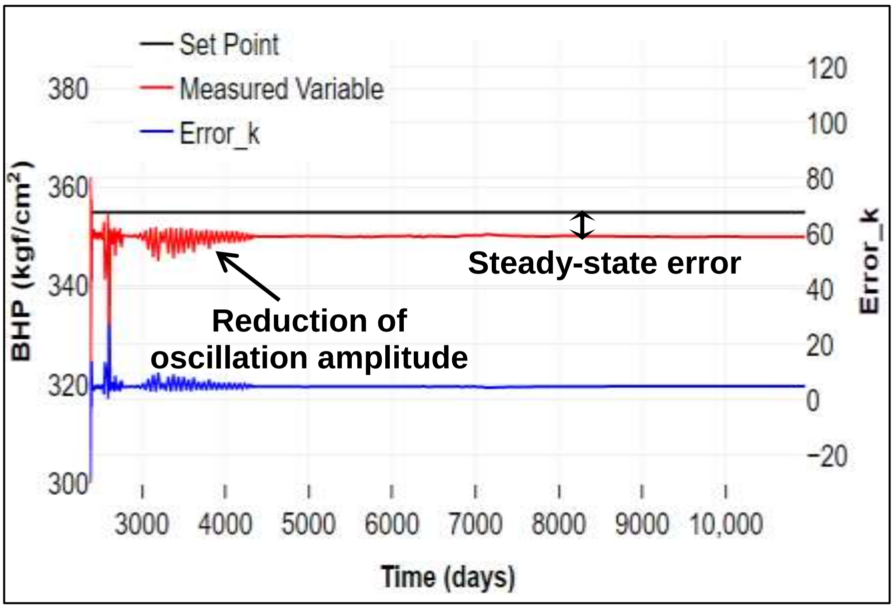

Figure 6.16: Well INJ 023 with P only controller ($\boldsymbol{K_C = 0.01}$, $\tau_I = \infty$ and $\tau_D = 0$).

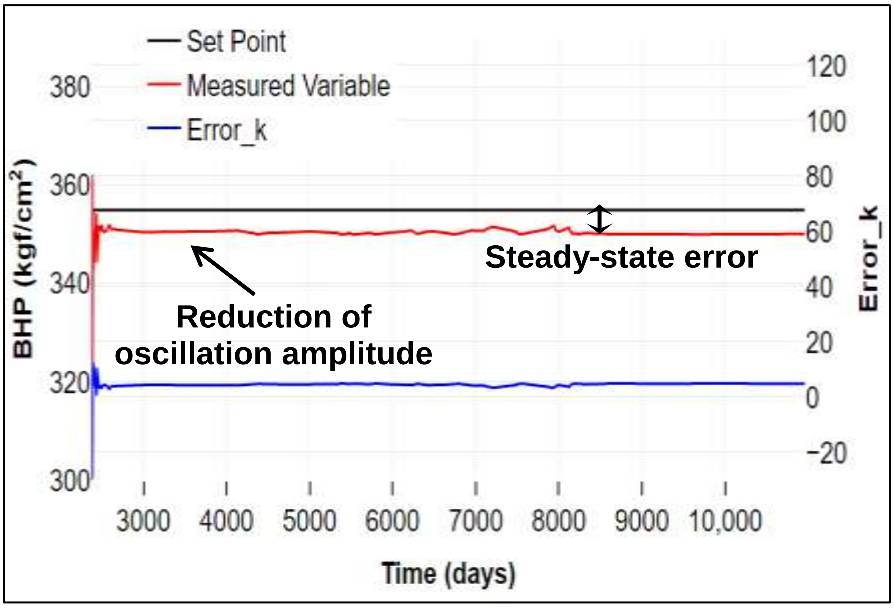

Figure 6.17: Well INJ 023 with P only controller ($\boldsymbol{K_C = 0.05}, \tau_I = \infty$ and $\tau_D = 0$).

Oscillation amplitude was reduced by the increase of K_C value, however the P only controller was not capable of eliminating the steady-state error. Therefore, the PI controller was implemented ($\tau_D = 0$) and parameter τ_I varied while K_C was fixed. Figures 6.18 and 6.19 represent respectively, the results obtained by the application of $\tau_I = 10$ and $\tau_I = 5$ with $K_C = 0.05$.

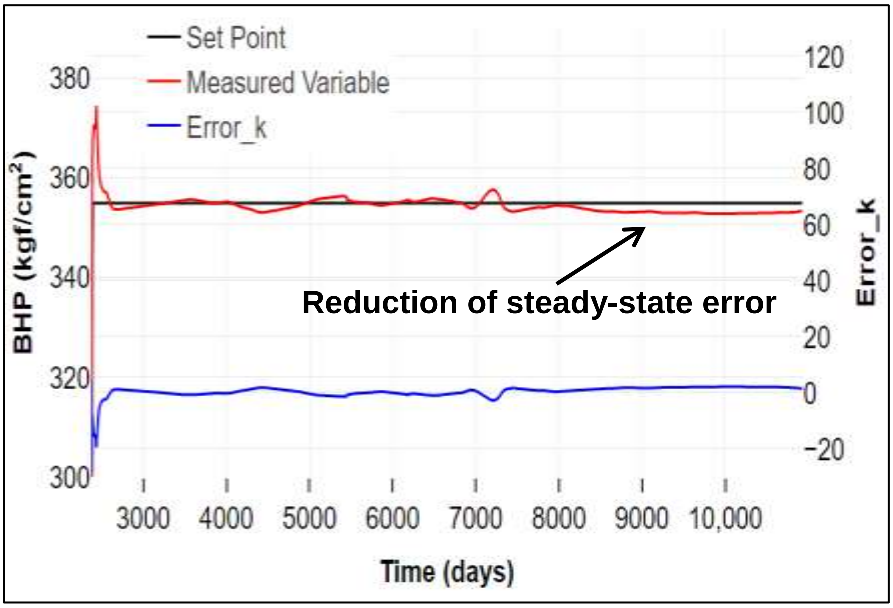

Figure 6.18: Well INJ 023 with PI controller ($K_C = 0.05, \boldsymbol{\tau_I = 10}$ and $\tau_D = 0$).

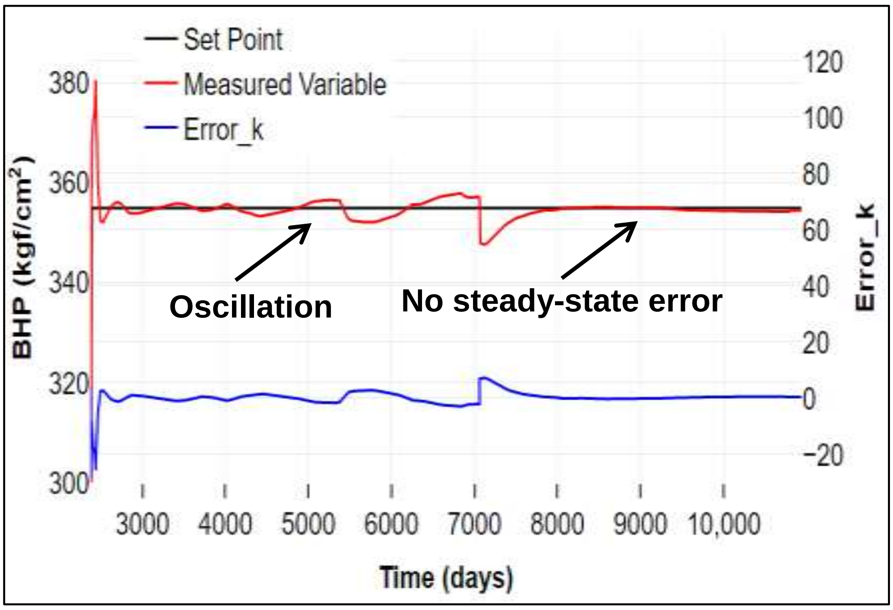

Figure 6.19: Well INJ 023 with PI controller ($K_C = 0.05, \boldsymbol{\tau_I = 5}$ and $\tau_D = 0$).

Steady-state error was eliminated reducing τ_I value, but the oscillation increased. Therefore, in the next step K_C was increased. Figure 6.20 shows the system results when K_C was increased to 0.12 and 5 was the value applied to integral time (τ_I).

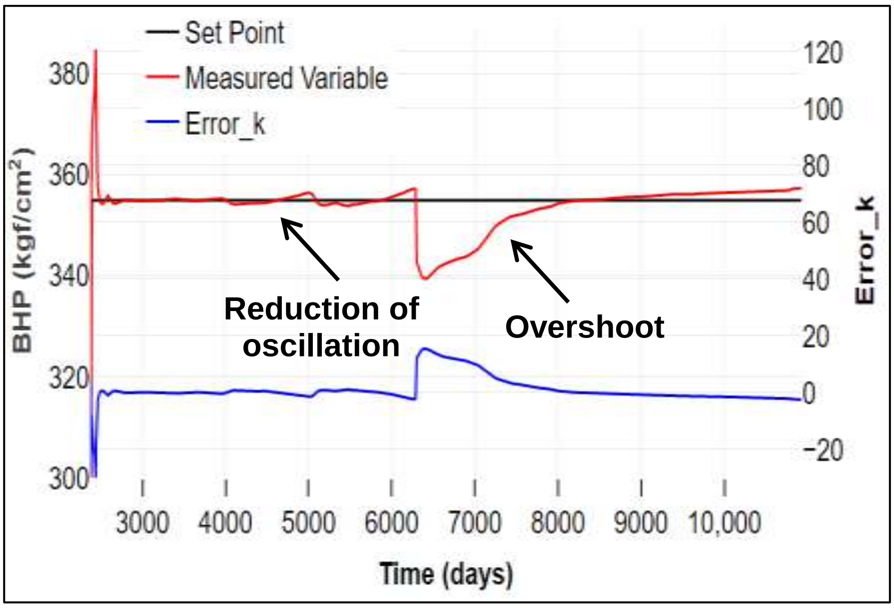

Figure 6.20: Well INJ 023 with PI controller ($\boldsymbol{K_C = 0.12}, \tau_I = 5$ and $\tau_D = 0$).

The increase of K_C value reduced the oscillations, but as a drawback, a big overshoot has appeared in the system. In this case, the derivative term was implemented by the addition of τ_D parameter, and a PID controller was applied. Figure 6.21 represents the final results obtained as a consequence of application of the following PID parameters: $K_C = 0.12, \tau_I = 5$ and $\tau_D = 0.6$.

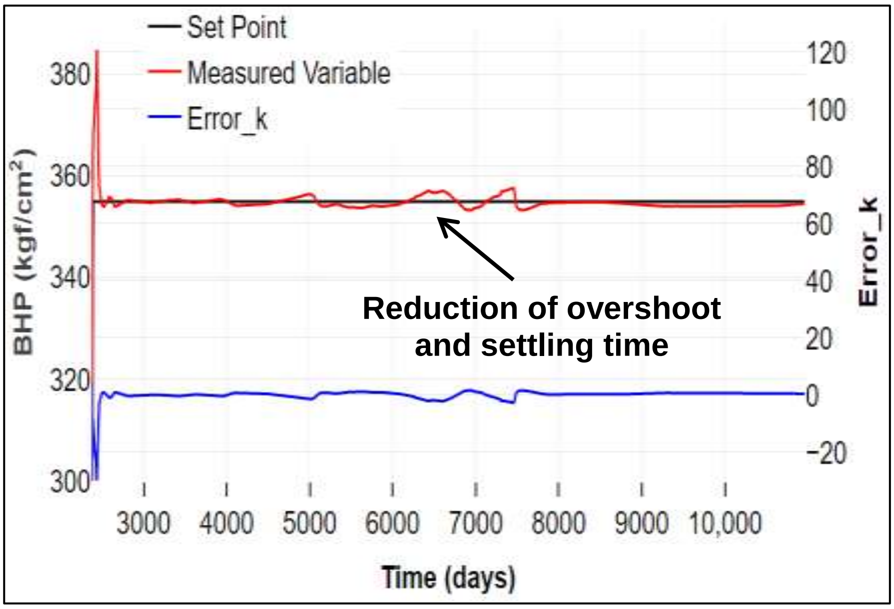

Figure 6.21: Well INJ 023 with PI controller ($K_C = 0.12, \tau_I = 5$ and $\boldsymbol{\tau_D = 0.6}$).

The overshoot and settling time were reduced by application of derivative term. As a result, the proper tuning of constants K_C, τ_I and τ_D of PID controller applied to well INJ 023 with a step change in set point value, minimized the oscillations and lead the system to stabilize with error close to zero.

In this case, all three PID parameters (K_C, τ_I, τ_D) worked as expected by classical theory (Seborg et al., 2016; Akakpo & Gildin, 2017), and Table 6.3 presents a summary of the effects caused by each constant in the results.

Table 6.3: Effects of changing a PID parameter independently in well INJ 023 with step change in set point value.

Parameter	Oscillation	Overshoot	Settling Time	Steady-State Error
$\uparrow \boldsymbol{K_C}$	Amplitude reduction	Increase	$---$	$---$
$\downarrow \boldsymbol{\tau_I}$	Increase	$---$	$---$	Eliminate
$\uparrow \boldsymbol{\tau_D}$	$---$	Decrease	Decrease	$---$

7 CONCLUSIONS

This work was fulfilled considering PID controllers as an innovative mechanism to avoid the presence of numerical instabilities integrating the whole petroleum system.

Automatic control based on closed loop feedback mechanism, in this case, PID controllers, is a well-known, simple and robust engineering technique. It has great potential to bring innovation when applied to an area where it is relatively new, such as integration between reservoir and production facilitates.

The following points represent conclusions derived from the new methodology based on control and automation engineering, PID controllers, proposed to mitigate oscillation in subsurface-surface couplings:

- In the case study, PID controllers shown to be a potential method to minimize the oscillations in subsurface-surface couplings, with low computational cost and avoiding access to reservoir internal code.
- The technique is flexible because depending on the scenario of application, PID controller can be designed by the selection of different terms as set point, measured and manipulated variables in order to make its performance as better and efficient as possible. However, the combination of a specific group of terms doesn’t work suitably minimizing the explicit coupling numerical instabilities.
- New formulated methodology outperformed locally and globally results of base case. Thus, it was validated.
- PID parameters (K_C, τ_I, τ_D) worked as expected by classical control theory.

7.1 Recommendations for future work

Based on the present work, the next studies are proposed:

- Define a straightforward mechanism to determine PID parameters in order to avoid manual calculation, which in some cases can be time consuming. Possibilities can include: (1) auto tuning and (2) gain scheduling.
- Generalize the methodology applying it in other scenarios: (1) reservoirs characterized by low permeability or presence of fractures, (2) different type of fluid as gas or heavy oils, and (3) complex production systems composed by manifolds, subsea separation units or intelligent wells.

- Attempt to design the PID controller using different terms as set point, measured and manipulated variables.
- Implement PID controller in the integration problem using a different perspective. In this case, try to define the system dynamic behavior through proper differential equations in order to determine transfer functions in Laplace domain, and directly stabilize the process stablishing controller step responses such as rise time, settling time and overshoot.

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APPENDIX A – COMPARISON OF LOCAL RESULTS IN TWO CASES: EXPLICIT COUPLING WITH PID CONTROLLERS AND DECOUPLED METHOD

Comparison of BHP and flow rate of injectors (INJ 006, INJ 010, INJ 017, INJ 019, INJ 021, INJ 022, INJ 023) and producers (PROD 010, PROD 025A, PROD 026) applying explicit coupling with PID controllers and decoupled method can be seen next.

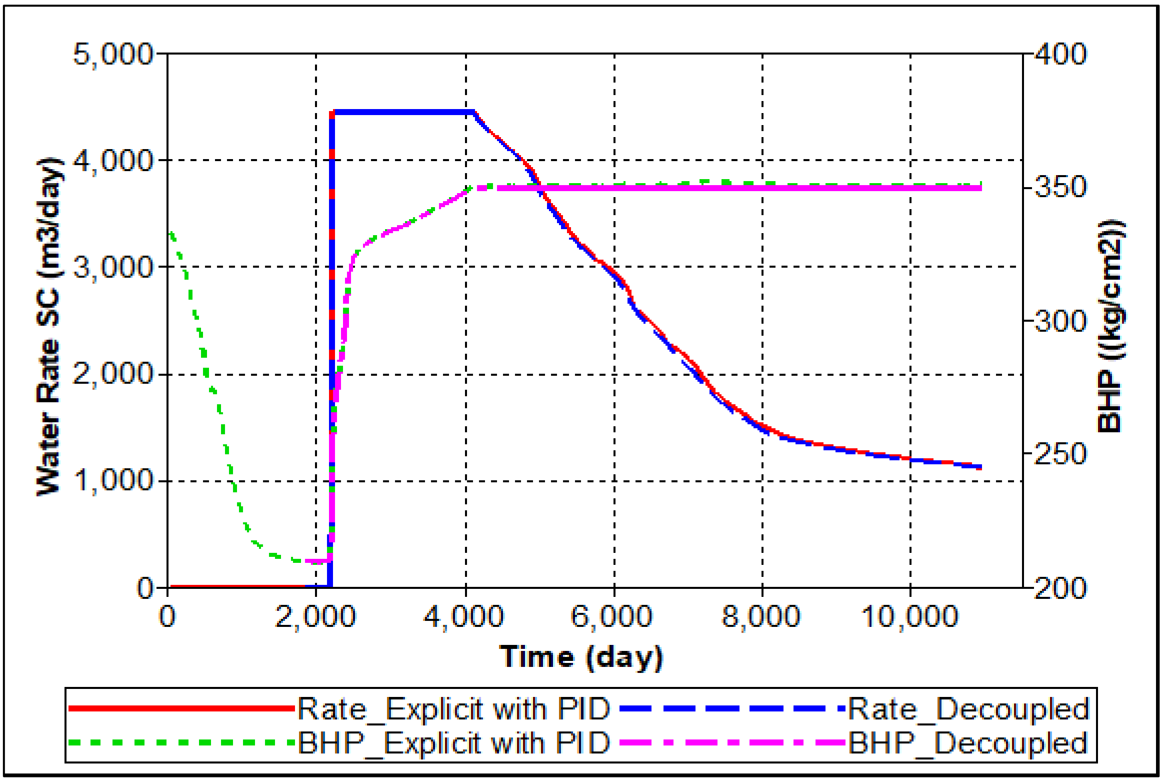

Figure AP. 1: Well INJ 006.

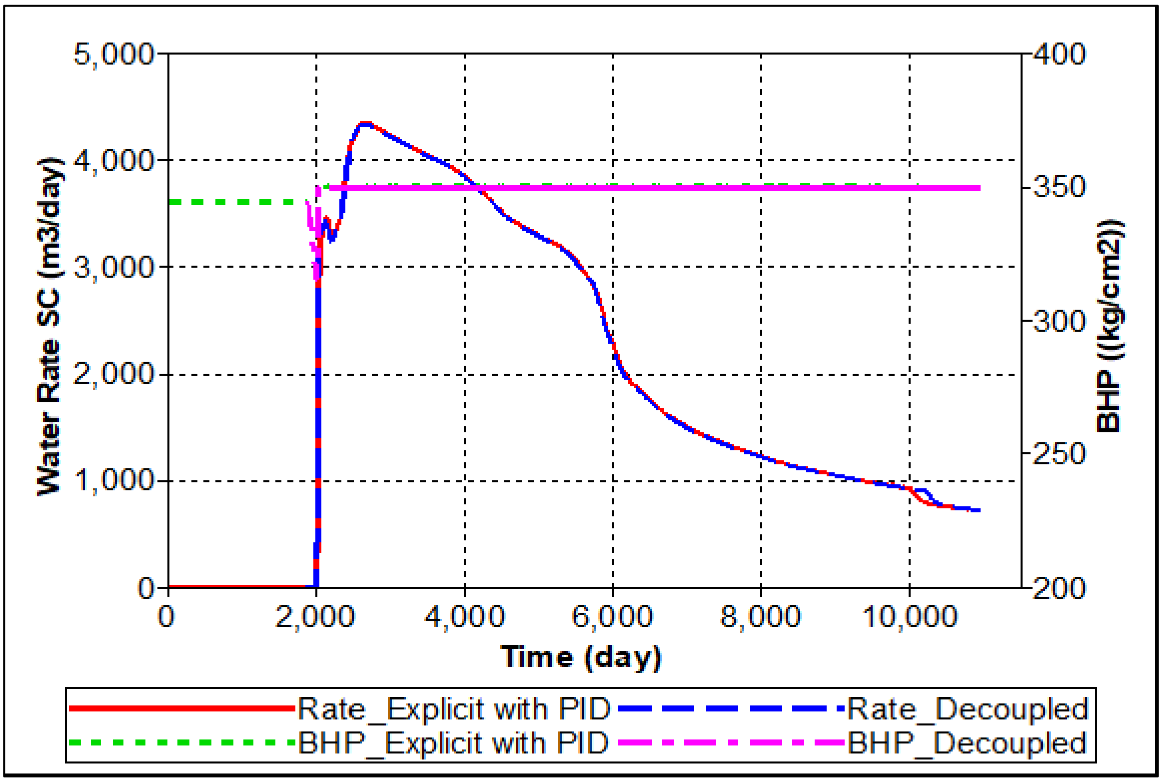

Figure AP.2: Well INJ 010.

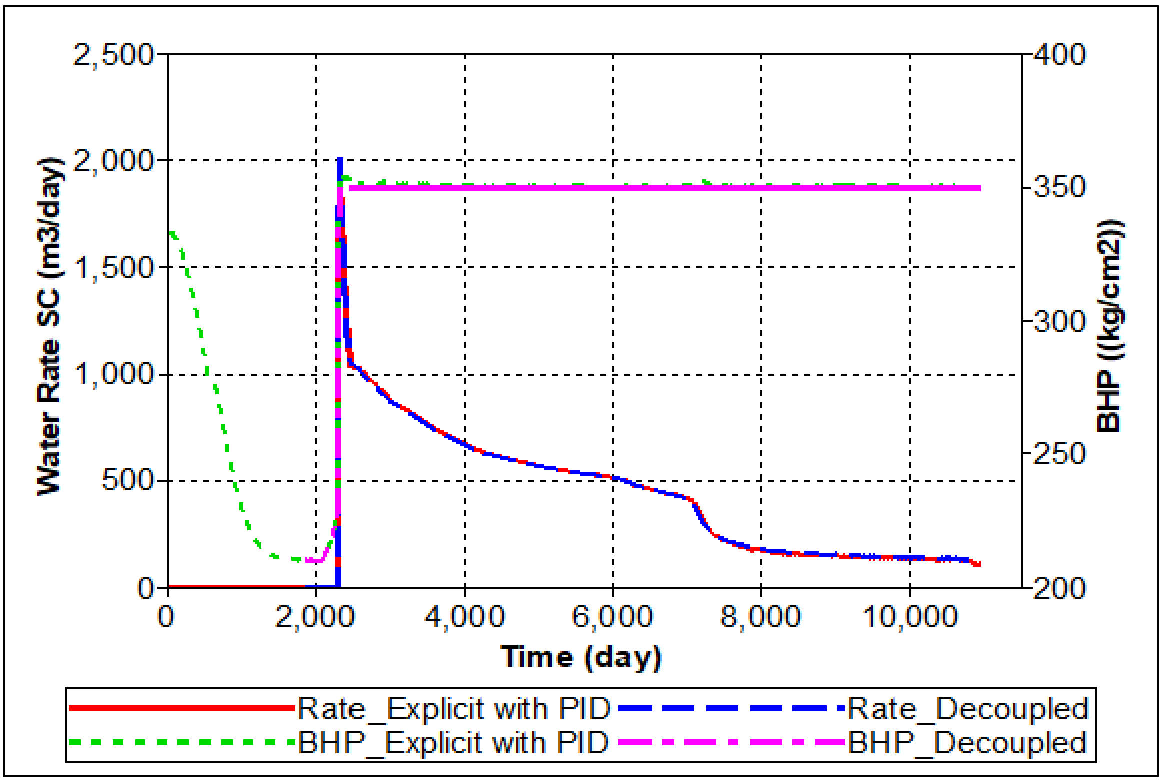

Figure AP.3: Well INJ 017.

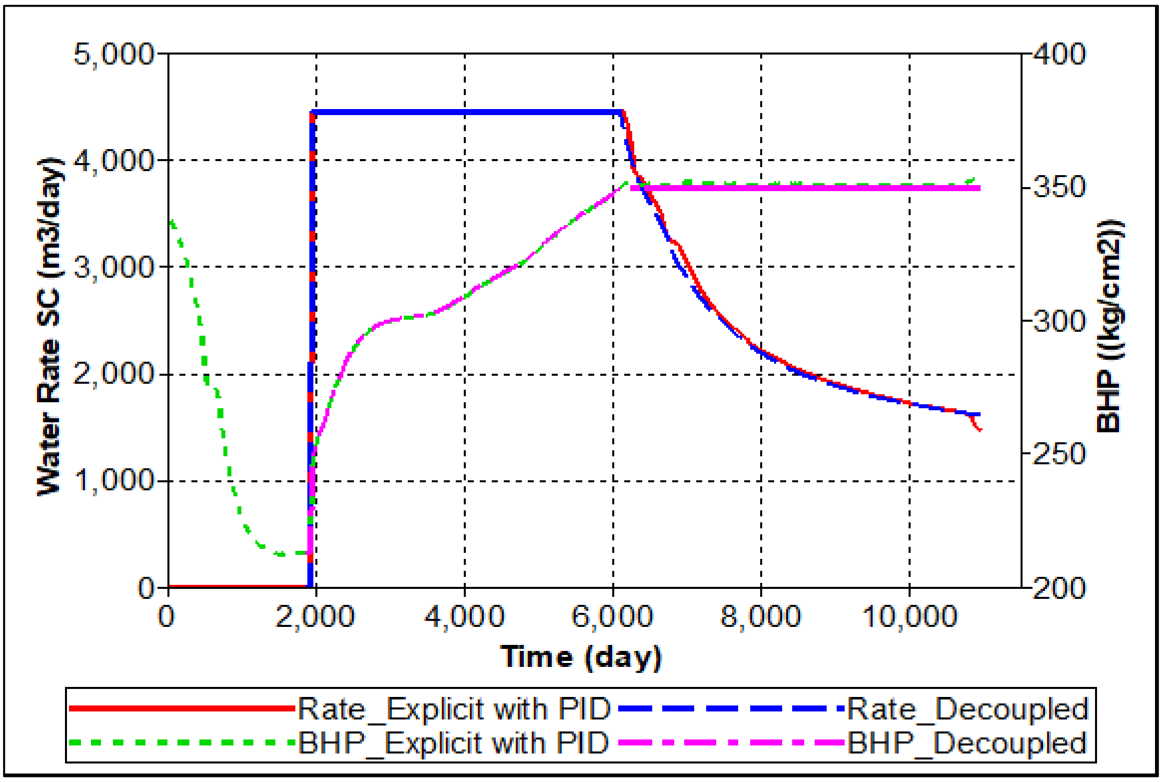

Figure AP.4: Well INJ 019.

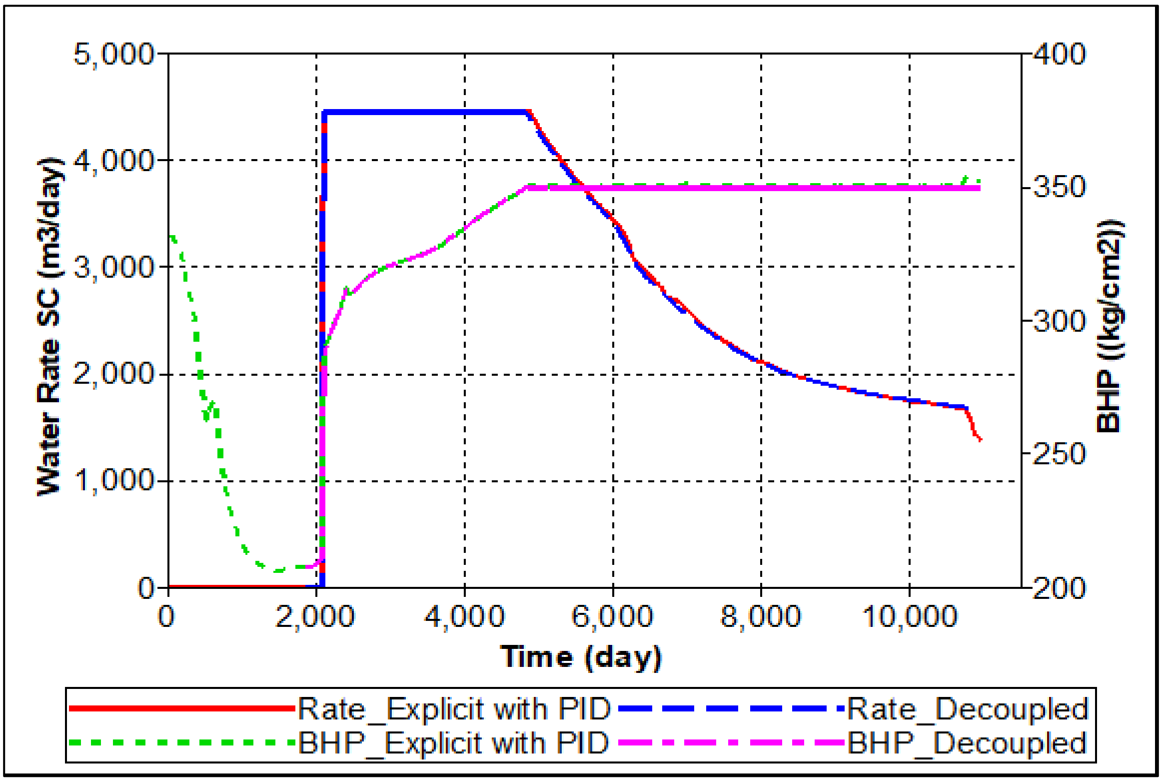

Figure AP.5: Well INJ 021.

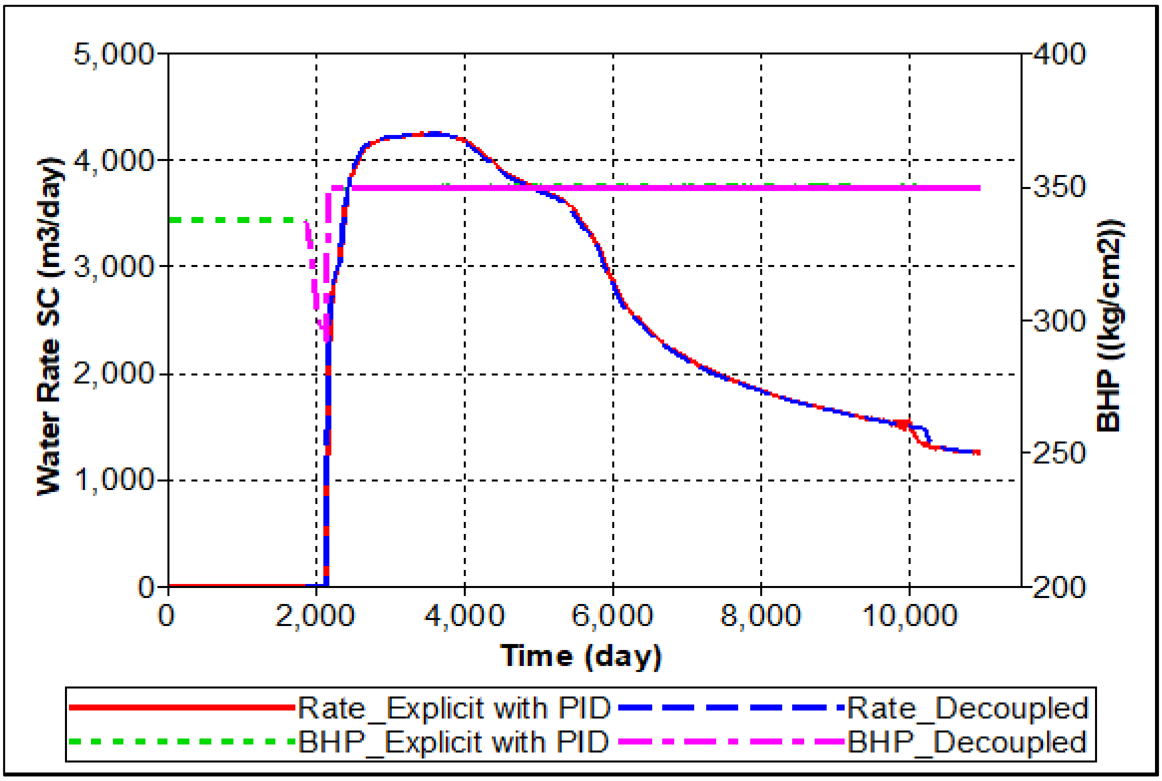

Figure AP.6: Well INJ 022.

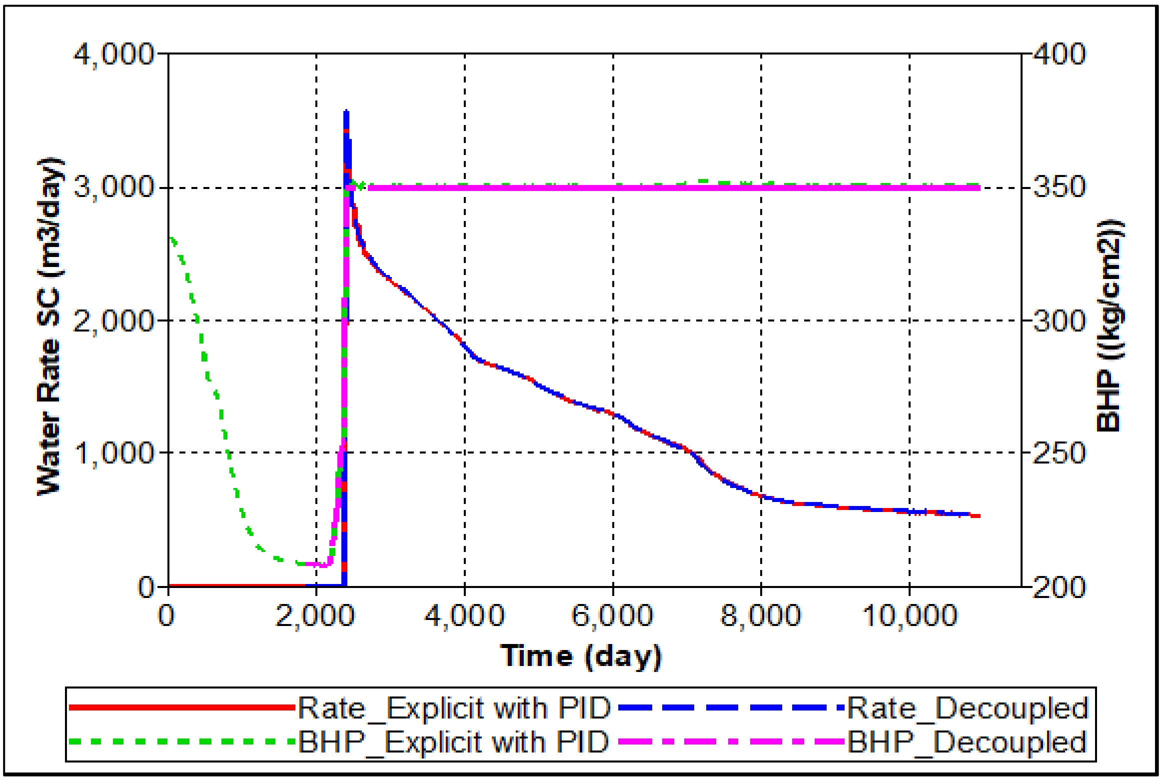

Figure AP.7: Well INJ 023.

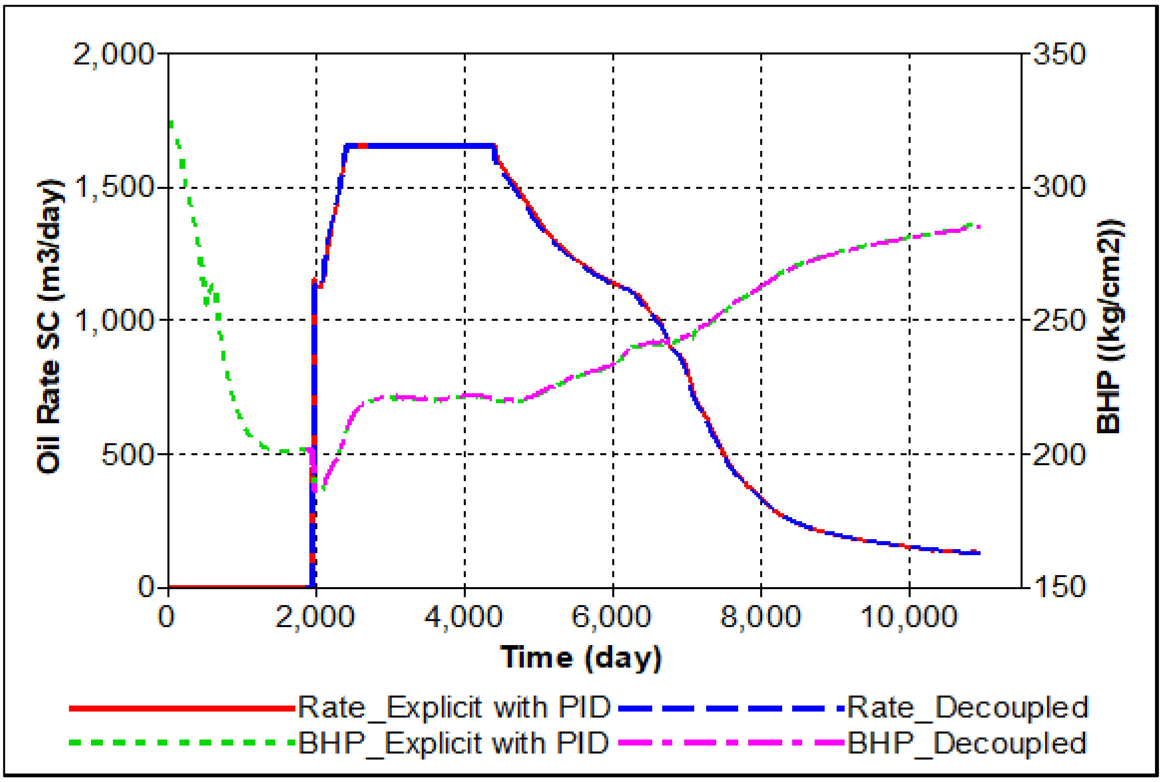

Figure AP.8: Well PROD 010.

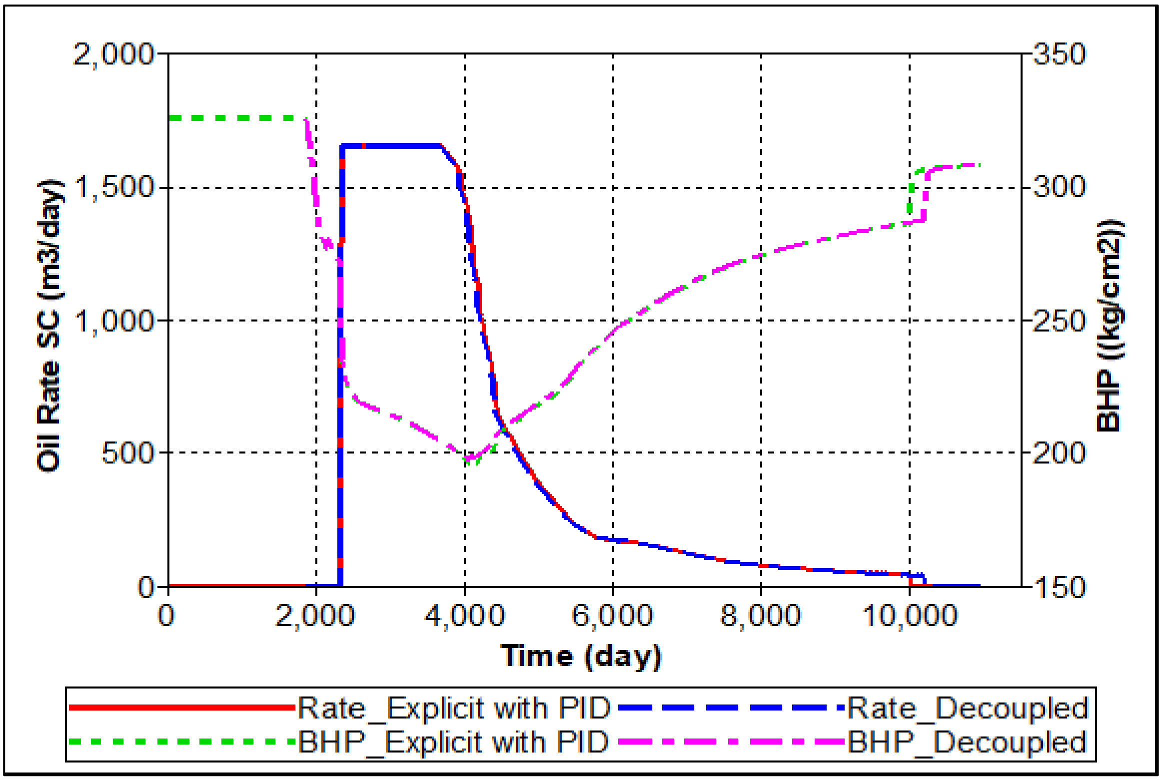

Figure AP.9: Well PROD 025A.

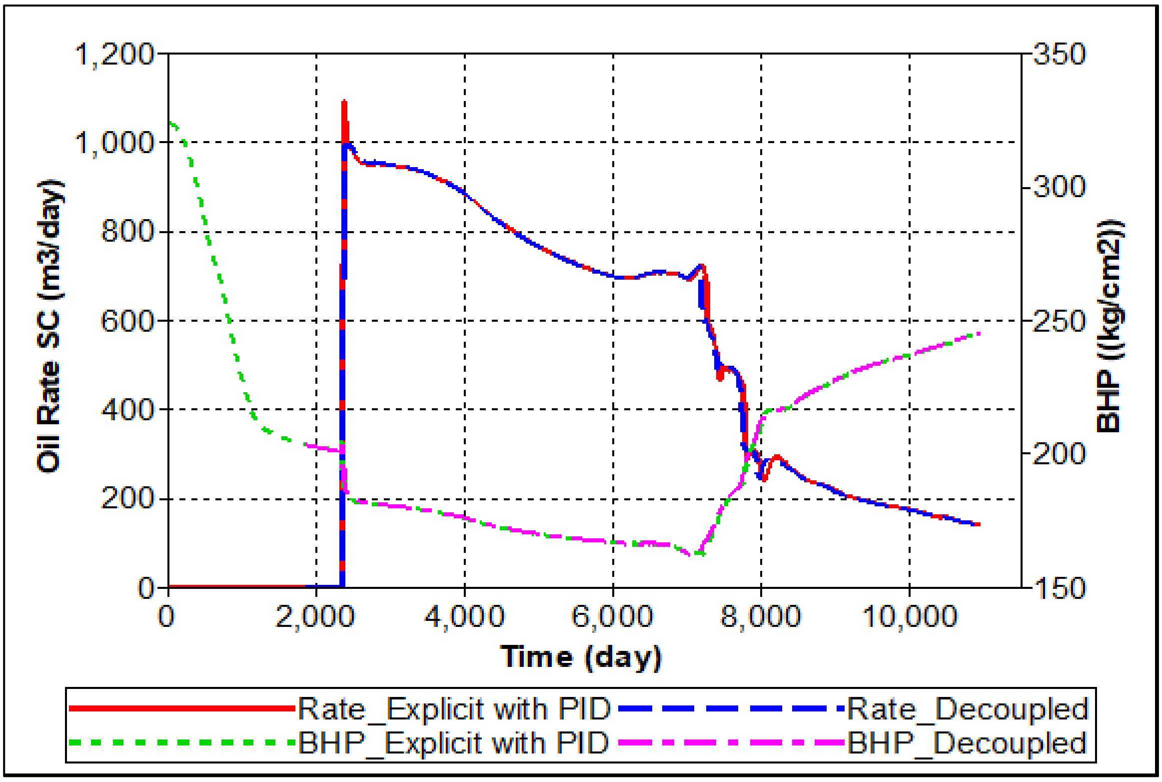

Figure AP.10: Well PROD 026.

ANNEX A – PID CONTROLLER MANUAL TUNING

According to Akakpo et al. (2017) and as can be seen in Figure A.1, increasing the proportional parameter and decreasing the integral parameter (leads to shorter rise time, but at the same time it leads to higher overshoot. The derivative parameter is not represented in Figure A.1, but has a unique effect on the system response. In fact increasing the derivative parameter leads to a decrease in the overshoot and settling time.

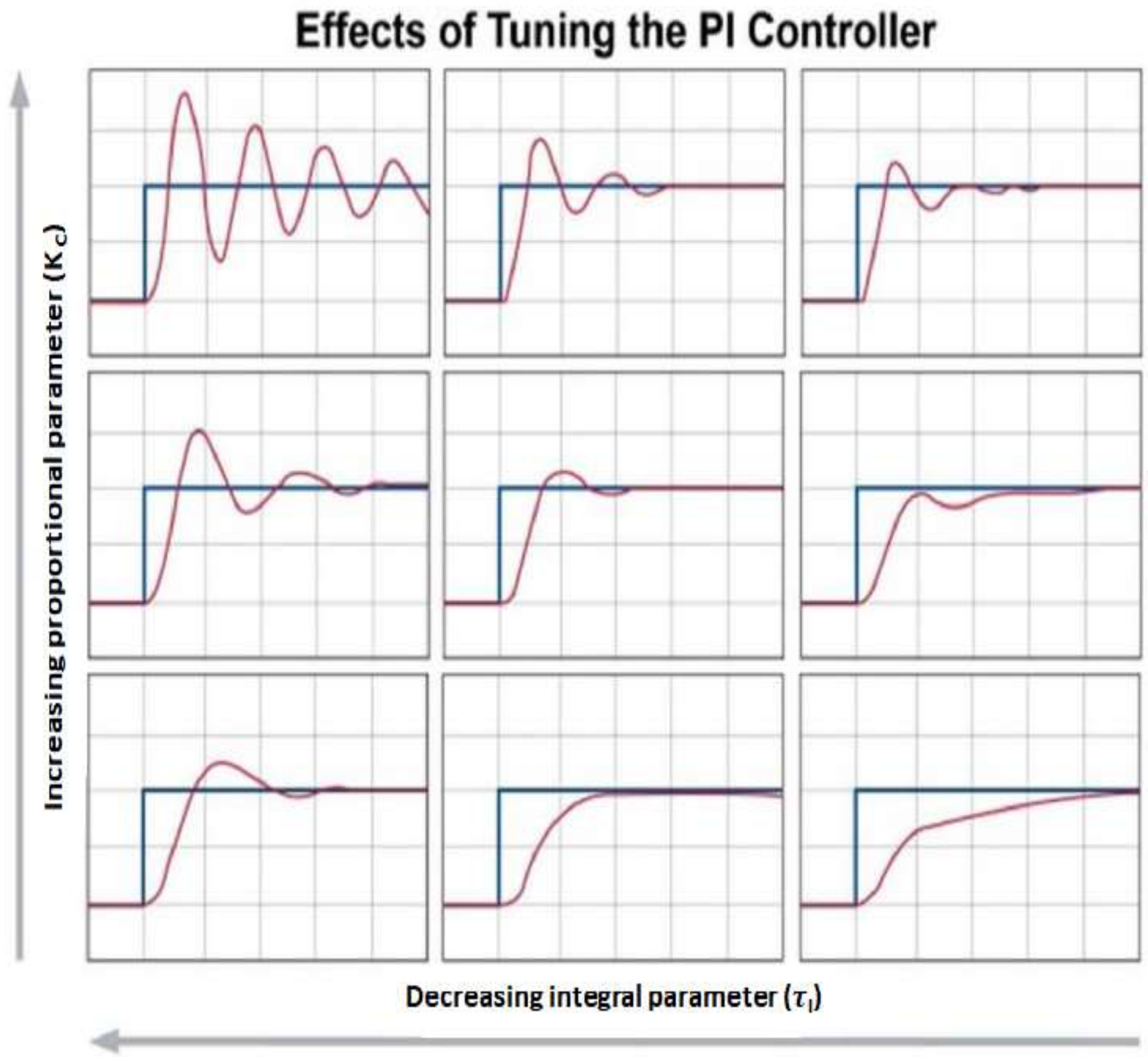

Figure AN.1: Effect of K_C and τ_I on the system response.