DILUENT INJECTION IN PRODUCTION SYSTEM WITH ESP-LIFTED WELLS

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Summary

In this study, the author models a single-well production system using bond graphs and techniques discussed during the course TEP4240. An oil production system includes all elements require for oil recovery from a reservoir to the surface. This particular model implements two improving oil recovery (IOR) techniques: electric submersible pumps (ESP) and diluent injection into an oil well. These techniques are used in non-conventional oil reservoirs, in particular heavy and extra-heavy oil reservoirs, in which their natural driving force is not enough to lift the production to the surface due to its high viscosity. ESP provide energy to the system and diluent injection reduces the fluid density and viscosity so the ESP works more efficiently and energy losses due to friction within the production tubing are reduced. The performance of the model was compared with a steady-state simulator developed by the author in a previous study (Ensalzado, 2016) implementing two study cases for a single-well system with two tubing sections and diluent injection: one with no pump lifting and the other including an ESP. The physical system was simplified considerably: constant oil properties along the well, isothermal conditions, and no discretization for calculating pressure losses in piping. For the first case, the deviation in bottom well pressure prediction was 5,0%, and the estimated oil flows in the tubing sections deviated -31,1% and -19,6% from the reference value respectively. For the second case, the results were significantly better: deviation in the bottom well pressure was 2,8% and the errors for the oil flows in the tubing sections were less than -4,5% for both variables. This last result is well within the error margin in engineering, and considering the model simplifications, the model performance was more than satisfactory

1. Introduction

For heavy and extra-heavy oil fields there is often a critical operational problem: oil viscosity. As a general case, oil found on these type of reservoirs has a high viscosity. The more viscous the fluid, the more energy and pressure losses along the production infrastructure. In order to overcome this problem, these fields are often developed with wells equipped with electric submersible pumps (ESP) to lift the pressure of the fluid to the surface. Another way to approach this challenge is to include diluent injection lines at various levels of the well (completion or along the tubing) to reduce the in-situ viscosity, hence reducing the pressure losses. When combined, these two IOR techniques are very promising, since the diluent injection may reduce the power requirement of the ESP and improve its performance.

Diluent injection is not a new term to the industry when it comes to heavy and extra-heavy oil recovery. Since 1999, there are references at Society of Petroleum Engineers (SPE) journals describing the potential of diluent injection to reduce the in-situ viscosity of these low-gravity oils, increasing the lifting capabilities and ultimately oil recovery. Garnett and Dee (Garnett & Dee, 1999) presented the results from a pilot test in the US including an implementation of light-oil injection in a heavy oil reservoir. They indicated that the oil average recovery increased 50 times using this technique. Rojas (Rojas, 2001) presented results on a new application in Venezuela for bitumen recovery (~8,5 °API) using diluent injection directly at the well completion. For this case study, the oil in-situ viscosity was 5.000 cP, at reservoir conditions (58 °C and 8100 kPa). More recently, in 2010, Brito, Garcia and Brown (Brito, Garcia, & Brown, 2010) presented results on an implementation of diluent and gas injection for the same purpose. This implementation is a step forward to the diluent injection technology, which is already considered traditional in Venezuela.

Despite being a standard practice on those countries, there is no information available about whether the diluent injection rate could be optimal or not for a given production system. In gas lifting, gas injection to the well improve the production of a well due to the reduction of density, and consequently reduction on the potential losses in the fluid column. However, after certain injection rate, the additional material added in the system increases the hydraulic losses due to friction (Golan & Whitson, 1996). A similar behavior is expected in diluent injection.

This topic was study in depth by the author (Ensalzado, 2016), resulting in the development of a comprehensive steady-state simulator. This simulator uses a traditional approach of dealing with the system physics: element by element, and solving numerous equations at the element boundaries to obtain the variables of interest. In the next sections, the author will explain an implementation of bond graphs for the same systems and benchmark the steady-state results with the simulator.

1.1. Objectives

The main objective of the study was to develop a simplified physical model based on bond graphs to describe oil production systems with ESP-lifting and diluent injection.

2. Nomenclature

2.1. Acronyms

ESP	Electric submersible pump
IPR	Inflow performance relationship
IOR	Improved oil recovery

2.2. Greek letters

γ	Specific gravity
ρ	Phase density [kg/m^3]
μ	Viscosity [cP]

2.3. Symbols

B	Phase volumetric factor
d_i	Pipe internal diameter
f_d	Darcy friction factor
g	Gravity acceleration
$\dot{m}$	Mass flow rate
P	Pressure
R_s	Gas in oil ratio
Q	Volumetric flow rate
J	Productivity index
u	Phase velocity
y	Vertical axis/direction

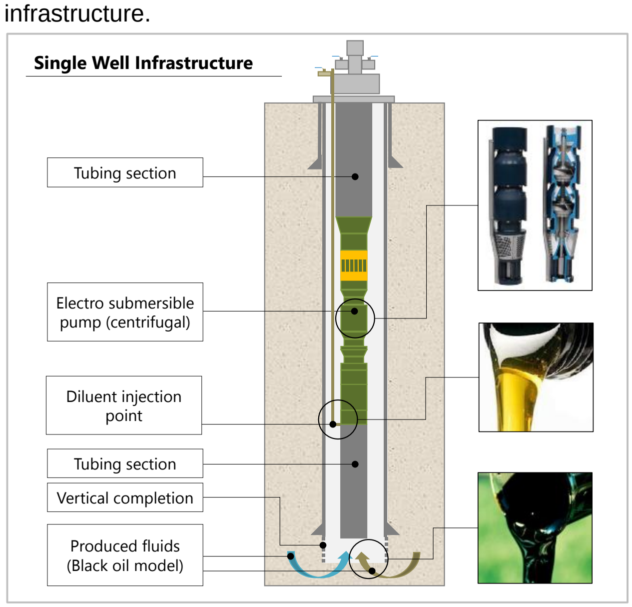
2.1. Subscripts

w	Water phase
wf	Bottom well or bottom hole
wh	Wellhead
ws	Reservoir
o	Oil phase
sc	Standard conditions
$p1$	Tubing section 1
$p2$	Tubing section 2
pm	ESP related

3. Model description

In Petroleum Engineering, a production system is a set of elements that allow producing oil and gas from a reservoir. Production systems include both wells and surface networks, typically grouped in what the industry qualifies as upstream. These elements can be modelled by a set of mechanical and thermodynamic equations to reproduce how they affect the phase behavior along its path to the surface. Figure 01 provides a simplified sketch from a single well, part of the production systems modelled in this study.

Figure 01. Simplified representation of a single well infrastructure.



Highlighting its elements, the well typically consists of the following elements:

- Vertical completion
- Tubing
- ESP
- Diluent injection point

Figure 02 indicates all elements included in the model developed using bond graphs. Also, a list of the most relevant system variables is included the right-hand side of the sketch.

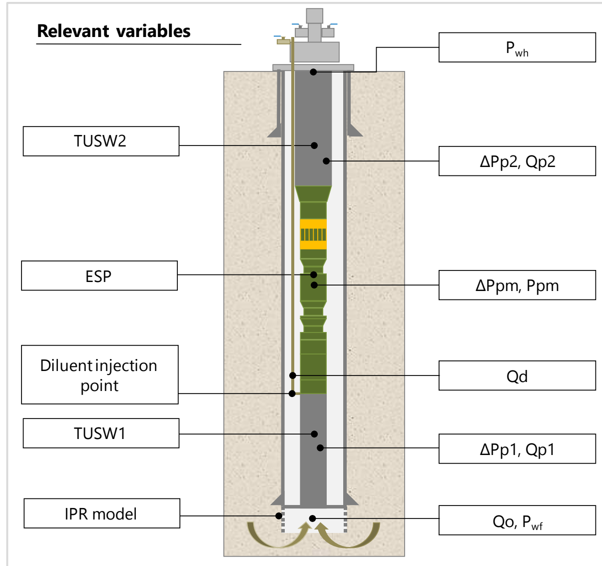
By ascending order, the model included the following elements:

1. Well flow source, using Norton approximation for real flow sources (Brown, 2006) and the IPR model well performance index to calculate the resistance.
2. The first tubing section, TUSW1, including its intertance, effect on weight and resistance.
3. A diluent injection point, using an ideal flow source.
4. An ESP, as a power source using a Thevenin approximation (Brown, 2006). The pump characteristics were used to model the corresponding resistance.
5. The second tubing section, TUSW2 including its intertance, effect on weight and resistance.
6. System wellhead represented as a connecting bond. For the study cases, the pressure on this bond was set to 6000 kPa.

In addition to the model formulation, and to provide a deeper insight on the capabilities of bond graphs for these kind of systems, two study cases were developed:

- A system formulation as described, without including the ESP-lifting unit.
- The system formulation as described, including the ESP-lifting unit after the diluent injection.

Figure 02. Relevant variables for the modeled system.



3.1. Main simplifications

The following list includes the main simplifications made over the model:

- The system is considered to be isothermal, e.g. there are no changes in the fluid properties due to a temperature gradient. All properties were calculated at bottom well temperature, 45 °C in this particular case.
- The fluid in the system is oil. It was not considered water and/or gas.
- Fluid relevant properties are considered to be constant per tubing sections. Also, they are calculated at an average pressure between the bottom well and the wellhead pressure.

3.2. Fluid model

To predict oil properties, a preliminary implementation of the black oil model was used (Ensalzado, 2015). For a detailed explanation of the model, a thorough revision of *Phase Behavoir* (Whitson & Brulé, 2000) is advised.

This model requires a minimum input to calculate the fluid properties at a given condition. To fairly represent the physical phenomena, heavy oil and diluent data was used. This information is included in table 01.

Table 01. Fluid properties of the model

Fluid properties	Crude oil	Diluent
°API	14,5	30,8
Specific gravity	0,9692	0,8720
Viscosity [cP] @ T1 [°C]	960 @ 37,8	9,8 @ 38,0
Viscosity [cP] @ T2 [°C]	329 @ 50,0	7,5 @ 54,0

In order to be consistent with the model, the flowrates in standard and local conditions were converted using black oil properties using the following expression.

$$\begin{bmatrix} \dot{q_g} \\ \dot{q_o} \\ \dot{q_w} \end{bmatrix} = \begin{bmatrix} B_g & -B_g \cdot R_s & 0 \\ 0 & B_o & 0 \\ 0 & 0 & B_w \end{bmatrix} \cdot \begin{bmatrix} \dot{q_{g,sc}} \\ \dot{q_{o,sc}} \\ \dot{q_{w,sc}} \end{bmatrix} \tag{1}$$

3.3. IPR model

The inflow performance relationship (IPR) provides a mathematical relation between the bottom well pressure and the oil flowrate coming from the reservoir. For this particular model, the well performance index (Well PI) was used. It follows the following equation.

$$Q_{sc} = J_o \cdot (P_{ws} - P_{wf}) \tag{2}$$

The Norton resistance associated with this flow source was based in this expression, using the following values:

Table 02. Inflow performance relationship (IPR) data.

IPR parameter	Value
Reservoir pressure [kPa]	20.000
Productivity index [Sm^3/d.kPa]	0,2

3.4. Tubing model

The resistance for the tubing model was developed based on the physical calculation for hydraulic losses (eq.3).

$$\frac{dP(y)}{dy} = f_d \frac{\rho(y) \cdot u(y)^2}{2 \cdot d_i} \tag{3}$$

The following expressions were for calculating the friction factor:

- Darcy's definition for laminar flow regimen
- Colebrook and White correlation for transition or turbulent flow.

The geometrical parameters of the two tubing sections are presented in the following table.

Table 03. Geometrical parameter of tubing sections.

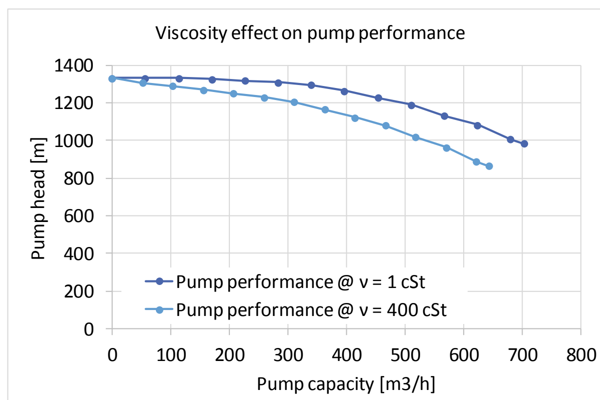
Tubing parameter	TUSW1	TUSW2
Internal diameter [m]	$1,270.10^{-1}$	$1,016.10^{-1}$
Roughness [m]	$1,524.10^{-5}$	$1,524.10^{-5}$
Length [m]	500	500

3.5. ESP model

As common industry definition an electric submersible pump, or ESP for short, is a vertical centrifugal pump with multiple stages, designed to be installed inside a well.

Since manufacturers provide the pump characteristics using water as a reference fluid, they had to be adjusted to take into account the fluid viscous effect. Figure 03 provides an example on how the characteristics is modified by this effect.

Figure 03. Viscosity effect on centrifugal pump performance.



The correction of the characteristics was done using the procedure suggested by the American Hydraulic Institute (ANSI/HI Standard 9.6.7, 2010), which is suitable for centrifugal pumps and viscous liquids up to 4.000 cSt. All the relevant equations were developed in a previous work (Ensalzado, 2015).

3.6. Diluent injection

As mentioned before, diluent injection into a production stream reduces its density and, usually, its viscosity. These two effects reduce both hydraulic losses in the system, and changes in potential energy within the flow column.

Calculating a new viscosity for a crude oil mixture is not a simple matter. For this model, the ASTM D7152 procedure was used (ASTM Standard D7152, 2011). An implementation of this procedure was already available and included in the system (Ensalzado, 2015).

3.7. Bond graph representation

The bond graph representation of the system is depicted in figure 04. As shown, the system is over-causal, since the flowrate in both tubing sections are dependent.

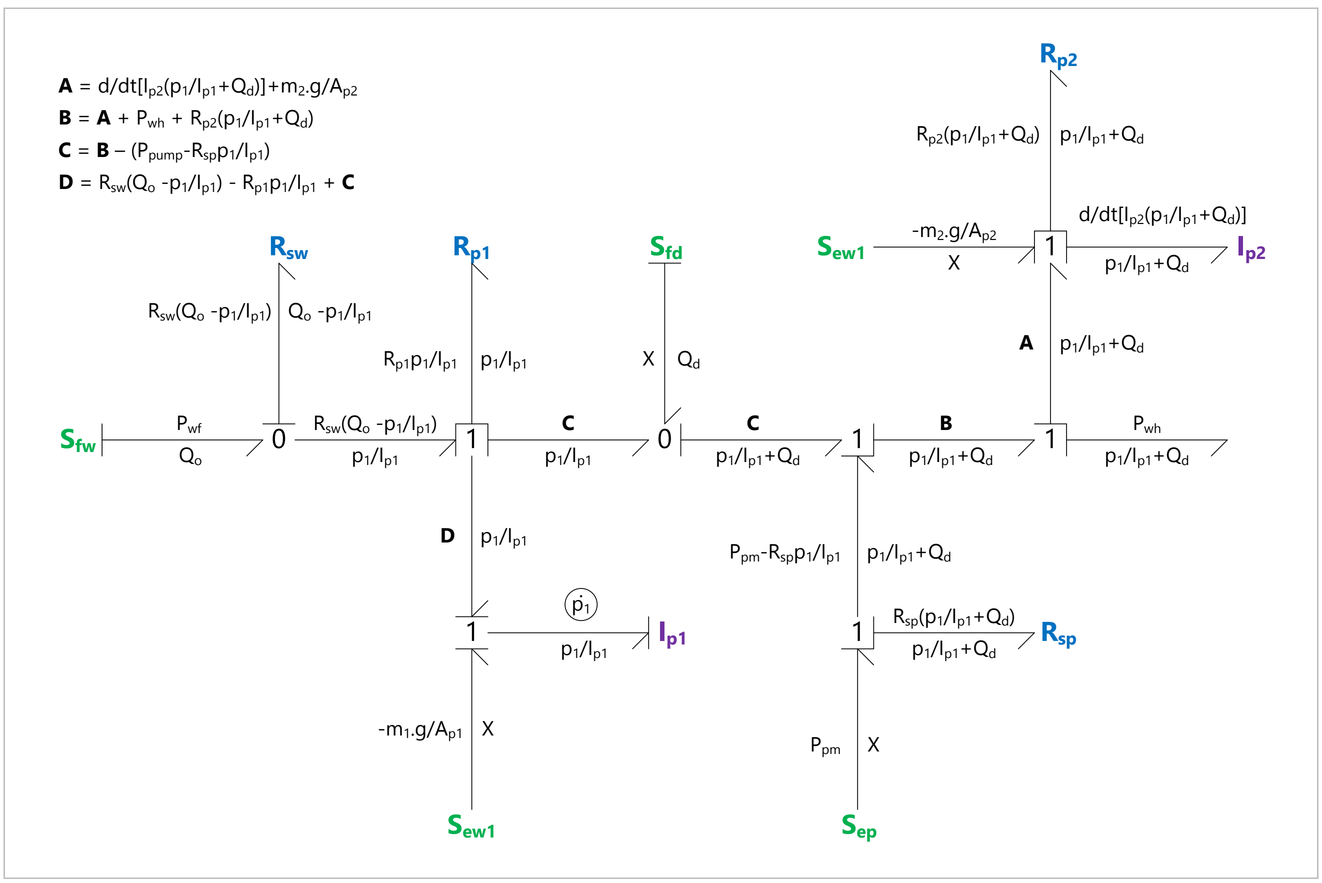
Despite showing a complex algebraic formulation, ordinary differential equation (ODE) system of first order describes the model. The state variable is the generalized momentum in the tubing section 1, given in [N/m^2.s].

In table 04 there is a list of all relevant physical variables in terms of the bond graph annotations.

Table 04. Relevant system variables and their formulation in terms of bond graph variables.

Variable	Formulation
P_{wf}	$R_{sw}(Q_o - p_1/I_{p1})$
$P_{pm,real}$	$P_{pm} - R_{sp}(p_1/I_{p1} + Q_d)$
Q_{p1}	p_1/I_{p1}
Q_{p2}	$p_1/I_{p1} + Q_d$
ΔP_{p1}	$R_{p1}(p_1/I_{p1})$
ΔP_{p2}	$R_{p2}(p_1/I_{p1} + Q_d)$
ΔP_{pm}	$R_{sp}(p_1/I_{p1} + Q_d)$

Figure 04. Annotated bond graph of the system (including state equation).



$$\frac{dp_1}{dt} = \frac{R_{sw}\left(Q_o - \frac{p_1}{I_{p1}}\right) - R_{p1}\frac{p_1}{I_{p1}} - R_{p2}\left(\frac{p_1}{I_{p1}} + Q_d\right) - I_{p2}\frac{dQ_d}{dt} - \frac{m_1 g}{A_{p1}} - \frac{m_2 g}{A_{p2}} - P_{wh} + P_{pm} - R_{sp}\left(\frac{p_1}{I_{p1}} + Q_d\right)}{1 + \frac{I_{p2}}{I_{p1}}} \quad (4)$$

4. System transient behavior

The model was implemented and validated in MATLAB, version 2015a. Tables 05, 06 and 07 show the results of a simulation with a time spam of 1000 s, using the `ode45` solver.

Table 05. System performance, with no downhole ESP

Variable	Unit	Reference	Simulation
P_{wf}	kPa	17205	16339
P_{wh}	kPa	5998	6000
Q_{p1}	m^3/d	595	780
Q_{p2}	m^3/d	903	1080

Table 06. System performance, with no downhole ESP

Variable	Unit	Reference	Simulation
P_{wf}	kPa	12406	12064
P_{wh}	kPa	5957	6000
Q_{p1}	m^3/d	1618	1690
Q_{p2}	m^3/d	1911	1990

Table 07. Relative error between system simulation and reference value.

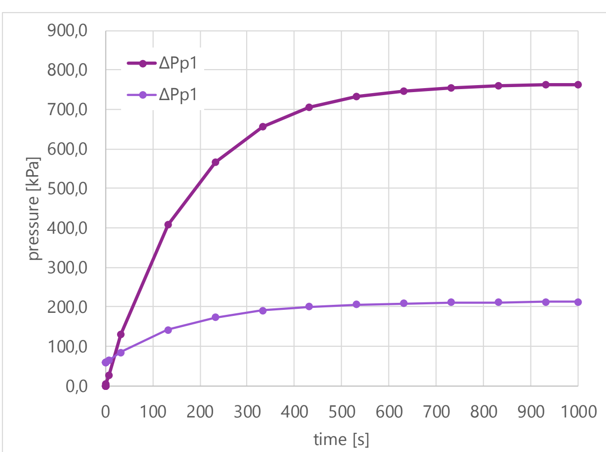
Variable	Unit	No ESP	With ESP
$\varepsilon_{\%}$, P_{wf}	kPa	5,0%	2,8%
$\varepsilon_{\%}$, Q_{p1}	m^3/d	-31,1%	-4,4%
$\varepsilon_{\%}$, Q_{p2}	m^3/d	-19,6%	-4,1%

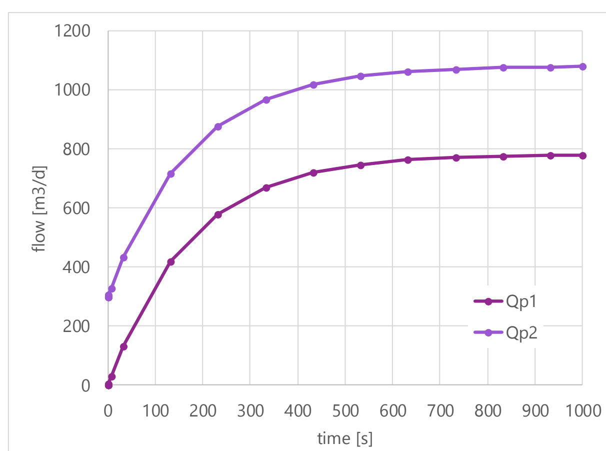
As depicted in figures 05 and 06, the system behavior is consistent with the physics involved: as the flow rates develop, the losses due to friction and potential energy increase. The same behavior was observed in the resistances from the well inflow (Norton source type) and the pump source (Thevenin source type).

The main reason for developing two study cases was to assess the model in terms of a more complex formulation. Comparing the system performance, including a ESP increases the well production in almost half its value (45,7%). It is clear that this value would depend on the type of pump installed in the well, number of stages, capacity and efficiency, however, the model was able to represent the phenomena satisfactorily, despite its simplified formulation.

This model could be used for studying the system response during startups or shutdowns. The previous simulator developed by the author is very accurate, when compared with commercial software packages, although it was not capable to model transient behavior.

Figure 05. System response with no downhole ESP. Time span [0 1000] s





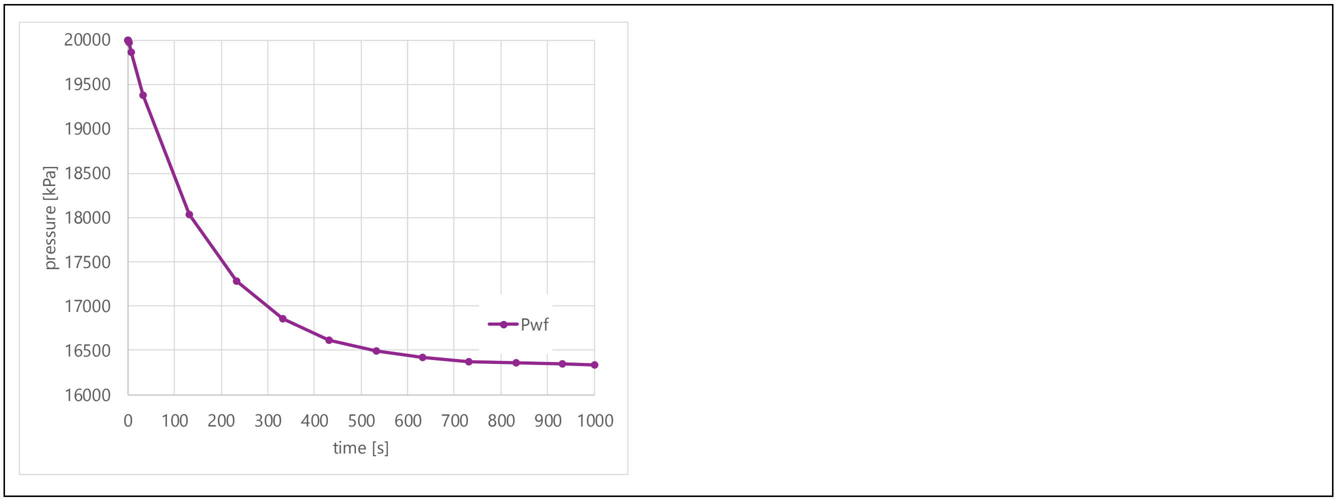
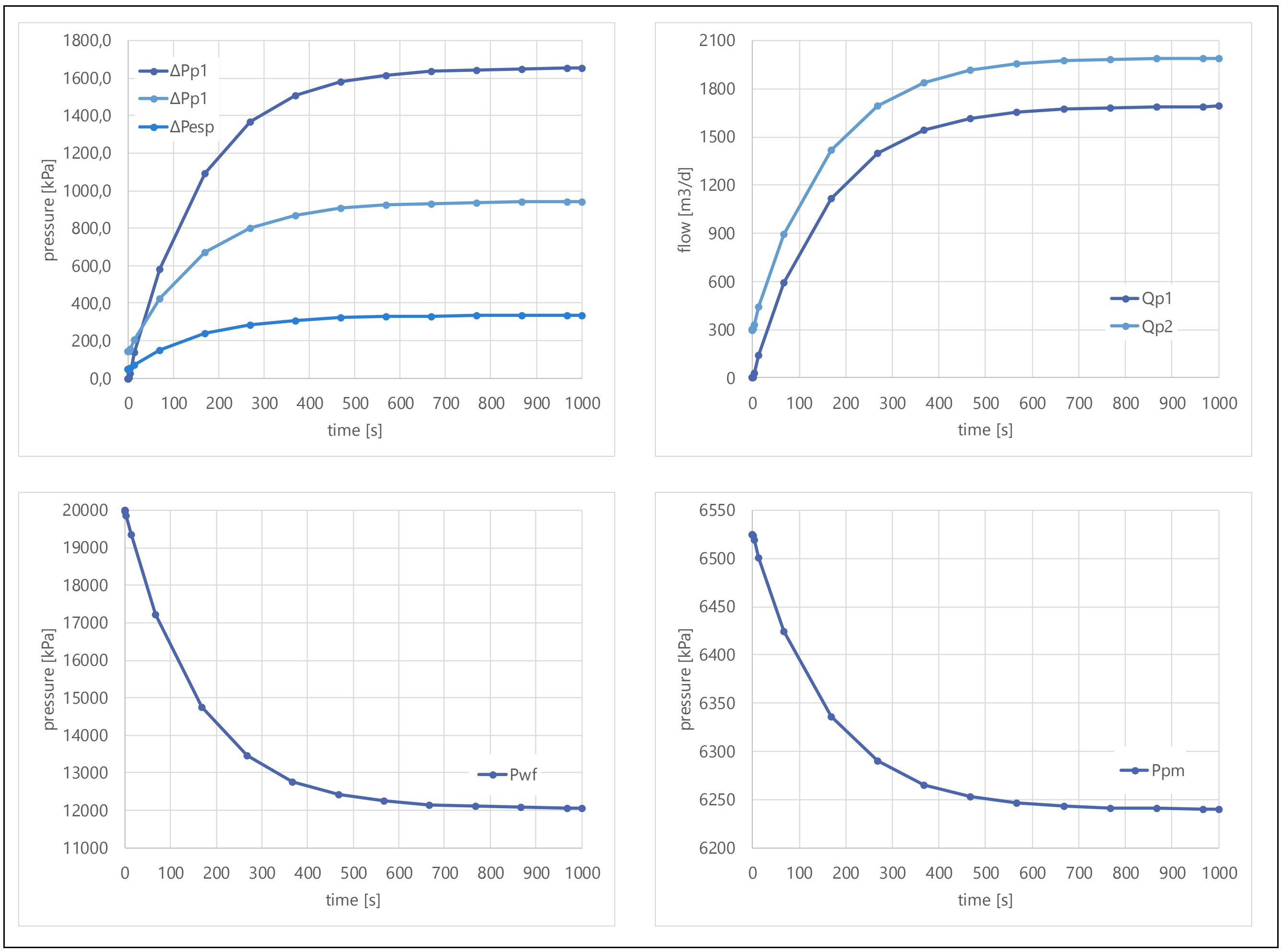


Figure 06. System response with downhole ESP. Time span [0 1000] s



5. Conclusions

- It was developed a simplified model of a single-production system based on bond graphs, including two vertical tubing sections, well productivity index as IPR model, diluent injection and ESP lifting.
- The bond graph model was benchmarked against a steady-state simulator for two cases: with and without ESP lifting. The main

variables studied were bottom well pressure (P_{wf}), and flowrates in both tubing sections (Q_{p1} and Q_{p2}).

- For both cases, the bottom well pressure estimation was fairly accurate: 5,0% for the system with no ESP-lifting and 2,8% for the system with ESP lifting.
- For the flowrate estimation, the first case (no ESP-lifting) results were as expected, showing a deviation of more than 20% in comparison with the reference value. The results from the second case (including ESP lifting) were surprisingly satisfactory, with deviations of less than 4,5% in both cases.
- Considering the results, the model developed represented accurately the production system when ESP lifting is included.

6. Further work

- Including heat transfer in the model, so changes in properties due to the geothermal profile are taken into account.
- Using functions depending on time to model the diluent injection.
- Using the system to model a single-well startup.
- Including several wells and work with an independent network to simulate clusters or production fields.

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