Maria Assumpta Nakibuule

Optimal Well Inflow Modelling

Master's thesis in Petroleum Engineering
Supervisor: Carl Fredrik Berg
Co-supervisor: Mathias Bellout
July 2021

Master's thesis

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To my little bundle of Suubi (Hope),
To mama, thank you.

Acknowledgement

I thank God for seeing me through this amazing journey. I would like to thank my parents Ms. Kiyingi Josephine and Mr. Kawunde Vincent for their unwavering belief, emotional and financial support in my academic journey. To Diana, Sheila and my entire family, thank you for your uplifting presence. I thank Rossini Silveira who opened my eyes to the endless opportunities available to me one of which led me to NTNU. I thank all my friends with whom i have been on this journey, and those who have cheered me on virtually and in person, specifically Mushabe Raymond, Ndawula Conifa, Apitta Noel, Depriye Okujagu and Lawino Mieke.

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Abstract

Horizontal wells (HWs) are deployed in hydrocarbon reservoirs to increase the reservoir contact area and hence recovery. Pressure losses along the length of the well, and Reservoir heterogeneity create an imbalanced well inflow profile. This is particularly problematic for HWs, and negatively impacts their productivity. In order to improve the HW productivity, Inflow control devices (ICDs) are used to control the flow of reservoir fluids into the well.

Several different workflows are used to determine the number and settings of the ICDs. Most use models of the reservoir around the well to run simulations to determine the placement and type of ICD from those available that performs best with the Horizontal well to achieve the desired reservoir performance outcome. In this thesis, a working philosophy is explored in which the optimal pressure distribution along the well path in the reservoir is determined with respect to the Net present value (NPV). The HW is then modelled with ICDs to replicate the optimal pressure distribution determined along the well path. The aim of the work is to develop a work process where ICDs are designed to replicate the well in flow that drains the reservoir in the most favorable way that maximizes the NPV.

In our workflow, the well is divided into well segments modelled as individual wells to allow for local and independent pressure setting. The Bottom hole pressure (BHP) for each well segment is optimized to maximize the NPV as the objective function. The NPV is a function of the cost of the amount of oil and water produced, and a fixed well cost. The optimal BHP values are then translated into the ICD strength settings. In this work, the placement of the modelled ICDs will coincide with the well segment location. The optimization is solved using the Particle swarm optimization (PSO) method with in the FieldOpt software.

The results from applying the workflow on two synthetic model cases are presented. The first case is a homogeneous reservoir, in which pressure losses along the well are minimised as the well is partitioned in to more well segments, this delayed water breakthrough. The second case is a heterogeneous reservoir, the control of fluid flow into the well improved as the number of well segments increased. More well segments gave more localised well control with respect to permeability distribution along the well path. For this case, the NPV is seen to peak at 6 well segments as the well cost starts to exceed the revenue.

Upon translating the optimal pressure distribution to ICD design, the HW performance with ICDs was improved for both cases. The method used to translate the optimal pressures to ICD

settings is a first order approximation, but performs well as the difference between the final production profiles of the segmented well and the well with ICDs is small.

Contents

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Code Listings

Acronyms

Pressure drop due to the constriction. 33–35

Pressure drop due to friction. 33, 35

AICD Autonomous inflow control Device. 8, 52

AICDs Autonomous inflow control devices. 1, 8, 52

APPS Asynchronous parallel pattern search. xiv, 17, 20, 28–32

BHP Bottom hole pressure. ix, xiv, xv, xvii, 3, 15, 19, 20, 23–25, 28–32, 35–38, 40, 45, 48, 52, 53, 69, 71–78

CS Compass search. 20, 32

FOPT Final oil production total. 49

FWPT Final water production total. 49

HW Horizontal well. ix, xiii, xiv, 1–3, 5, 6, 8–10, 33, 40, 41, 46–49, 52, 53

HWs Horizontal wells. ix, 1–3

ICD Inflow control device. ix, xiii, xiv, 1, 2, 7–15, 19, 20, 32–37, 40, 46–49, 51–53

ICDs Inflow control devices. ix–xi, xiv, xvii, 1, 2, 6–9, 11, 19, 20, 24, 35, 38, 40, 41, 44–49, 51–53

NPV Net present value. ix, xiv, xvii, 15, 19–21, 23, 24, 28–33, 35, 37, 38, 42, 47–49, 51

PPS Parallel pattern search. 16, 17

PSO Particle swarm optimization. ix, xiii, xiv, 17, 18, 20, 28, 30–32, 48, 51, 52

WIC Well index calculator. 23

WLPR Well liquid production rate. 37, 40, 45, 49, 52

Chapter 1

Introduction

Reservoir management is the use of human, financial and technological resources to maximize profit from a hydrocarbon reservoir by optimizing recovery and minimizing costs (Satter et al. 1994). The high field development costs coupled with the need to maximize recovery require that the field operations are effectively and efficiently executed through good reservoir management practices. One such practice is the model based optimization of field operations. These field operations include well pressure and or rate controls (Jan-Dirk Jansen et al. 2008), well locations (Bellout et al. 2012) and well type.

Horizontal wells (HWs) are a type of wells deployed to improve oil recovery as they increase the reservoir contact area, and allow drainage across reservoir barriers. Unfortunately, with increase in wellbore length, issues such as water and or gas coning, and early water breakthrough caused by reservoir permeability heterogeneity and non uniform flow from the heel to toe of the well are more prevalent. These issues require different pressures along the well for optimal production, thus the need for well inflow control (Bybee 2010). Inflow control devices (ICDs) are added to the HW completion to achieve control of fluid flow in to the well.

ICDs balance the inflow along the wellbore by generating an additional pressure drop along the well, restricting flow from the high production areas delaying water and gas breakthrough, and improving the reservoir drainage sweep. In this work, ICD strength refers to the additional pressure drop the ICD applies along the well. Passive ICDs are those whose strength is not adjustable once they are deployed, and the ICDs function as initially designed despite the changing reservoir conditions (Li et al. 2011). This requires that the ICD settings should be such that the ICD does not have a negative impact on the reservoir throughout the life of the well. Another ICD type are the Autonomous inflow control devices (AICDs). These are capable of adjusting the flow restriction applied depending on the fluid phase flowing as discussed by James and Hossain (2017).

Several different methods are used in the industry to determine the strength, number and placement of ICDs to be used. These methods use simulations to determine which ICD completion design performs best with the reservoir to achieve the desired outcome. The simulation is done on a trial and error basis using the available ICDs in different completion configurations.

An example of such an ICD completion design procedure is outlined in Javid et al. (2018), where a well centric model extracted from the full field reservoir model is used to simulate ICD performance by carrying out sensitivity studies on the ICD strength and placement. Such a method places focus on only the reservoir performance near the well bore to determine ICD design. In the long run such an ICD becomes ineffective as the reservoir properties change during production.

The aim of this work is to develop a procedure that determines the optimal pressure distribution along the well in a reservoir, and uses this as a basis to design the ICD completion settings. The well is divided into a number of independent well segments in order to find the optimal pressure distribution along the well path. The optimal pressure distribution is determined by optimizing the control settings of the individual well segments. The pressure distribution is then translated into ICD strength settings. The expected outcome of using such a workflow is that the ICDs modelled take into account the optimal performance of the entire reservoir. Further, the ICD design is not limited by existing tools and their settings range. The objectives of the work are:

1. Propose and test a workflow for determining the optimal pressure distribution along the well. The workflow consists of two nested loops, in the outer loop multiple well segments are modelled with OPM Flow reservoir simulator. In the inner loop the well settings for each well segment configuration are optimized using a derivative free algorithm in FieldOpt.
2. Develop a Python code to automate the proposed workflow.
3. Model synthetic reservoir models to be used as study cases to test the workflow using the automation code.
4. Investigate the nature of the optimization problem and determine the most suitable optimization algorithm to be used in the workflow.
5. Model ICDs whose settings are translated from the results of the proposed workflow to replicate the optimal pressure distribution along the HW.

This work contains 6 chapters where the background chapter is a brief literature review of Horizontal wells (HWs), the need for inflow control, Inflow control device (ICD) design, and different optimization algorithms that can be employed in the work. In the methodology chapter, the workflow proposed and the code written to automate it are described, the setup of the optimization problem to be solved within the workflow is discussed, a description of the synthetic models to be used as study cases is given, and finally the method used to translate the optimal pressure distribution to ICD settings is presented. The results of applying the proposed workflow to the study cases are presented in the results chapter, and the results are discussed in the discussion chapter. Finally, in the conclusion chapter we draw conclusions on the outcomes of the study cases and performance of the workflow.

Chapter 2

Background

2.1 Horizontal Well Production and Performance

Horizontal wells (HWs) have been used as an improved oil recovery technique since 1930, with the aim of improving recovery leading to an increase in economic returns (Joshi 2003). HWs offer a larger reservoir drainage area, as they increase the contact area between the reservoir and the wellbore. They also allow for draining across natural barriers in highly compartmentalized reservoirs.

HW have led to an increase in recovery, reduction in the costs and required number of platforms for field development. These benefits outweigh the costs of deploying HWs especially in multilayered reservoirs with large differences in vertical permeabilities, which has led to earlier return of investments. Despite their advantages as stated above, HWs face several challenges, one major challenge is frictional pressure losses along the well which create a heel and toe effect in which higher production rates are seen at the heel than at the toe (Ozkan et al. 1999; Penmatcha et al. 1999; Dikken 1990). The resulting non uniform draw down profile along the wellbore length as seen in Figure 2.1 reduces the benefit of improved well productivity that is associated with long horizontal wells (Li et al. 2011).

The friction pressure losses along the well create a non uniform draw down profile along the well bore as shown in Figure 2.1, increasing the tendency of early water breakthrough and gas coning at the heel (Penmatcha et al. 1999). Horizontal well productivity is also affected by heterogeneities in reservoir properties with water and or gas breakthrough occurring at high permeability areas (Li et al. 2011).

Analytical work in the past, such as the Joshi model explained in Joshi (1988), assumed infinite conductivity of the HW. In the model, the pressure loss due to friction along the HW wellbore length is neglected such that the Bottom hole pressure (BHP) exerted at the heel is the same at the toe. Penmatcha et al. (1999) and Ozkan et al. (1999) developed models showing how such an assumption only applies when the friction pressure loss in the wellbore is small compared to the reservoir draw down such as in HWs with a large tubing diameter and short well length (Li et al. 2011). Reservoir draw down is the difference between the well

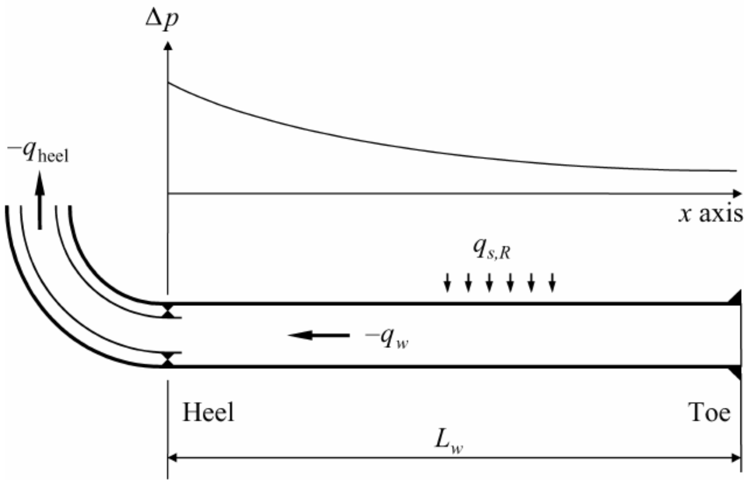


Figure 2.1: Horizontal well with non uniform draw down profile along wellbore length (Jansen 2003).

pressure and the average reservoir pressure .

Figure 2.3 from Penmatcha et al. (1999) is used to illustrate this. Ep is the error arising from neglecting friction pressure loss along the wellbore in well productivity calculations. Using Figure 2.2, assuming a homogeneous reservoir, P_e is the pressure at the outer boundary of the reservoir, $P_w(x)$ pressure variation along the wellbore length due to friction pressure losses, the well inflow equation will thus be;

$$q_s(x) = J_s(x)[P_e - P_w(x)] \tag{2.1}$$

Where;

- q_s is the flow per unit length of well bore.
- $J_s(x)$ is the productivity index per unit length of the wellbore. Assuming the reservoir is homogeneous, single phase oil system at steady state, this is assumed to be constant, such that;

$$q_s(x) = J_s[P_e - P_w(x)] \tag{2.2}$$

Integrating Equation 2.2 along the entire length of the well to give the total flow rate from the well with pressure drop in the wellbore included ; $Q_{w,fric}$ and without ; $Q_{w,nofirc}$:

$$Q_{w,fric} = J_s P_e L - J_s \int_0^L P_w(x) \tag{2.3}$$

$$Q_{w,nofirc} = \int_0^L J_s[P_e - P_{w,0}] = J_s L[P_e - P_{w,0}] \tag{2.4}$$

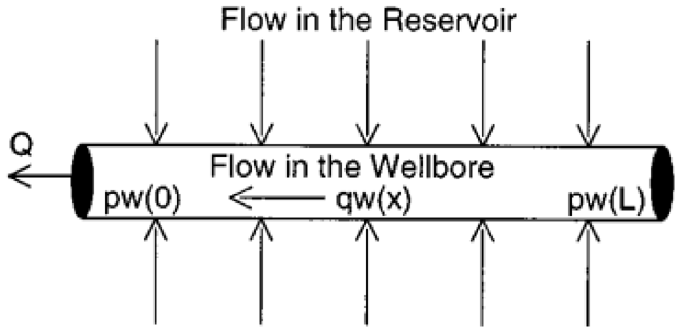


Figure 2.2: Illustration of coupling of the reservoir and wellbore used to describe effect of friction on HW productivity in Penmatcha et al. (1999).

The productivity error E_p, is then defined as

$$E_p = \frac{Q_{w,fric} - Q_{w,nofirc}}{Q_{w,fric}} \tag{2.5}$$

Using Equations 2.4 and 2.6 to define the well flow rates with and without friction pressure losses included the productivity error term is reduced to Equation 2.8 which is the ratio of the average pressure drop along the wellbore and the draw down at the heel.

$$E_p = \frac{\frac{1}{L}\int_0^L [P_w(x) - P_{w,0}]dx}{P_e - P_{w,0}} \tag{2.6}$$

The concave trend of the graph in Figure 2.3 for a given pressure draw down shows that productivity of well increases with increasing well length until a point beyond which there is no more increase in well productivity with length due to the well bore pressure losses (Penmatcha et al. 1999).

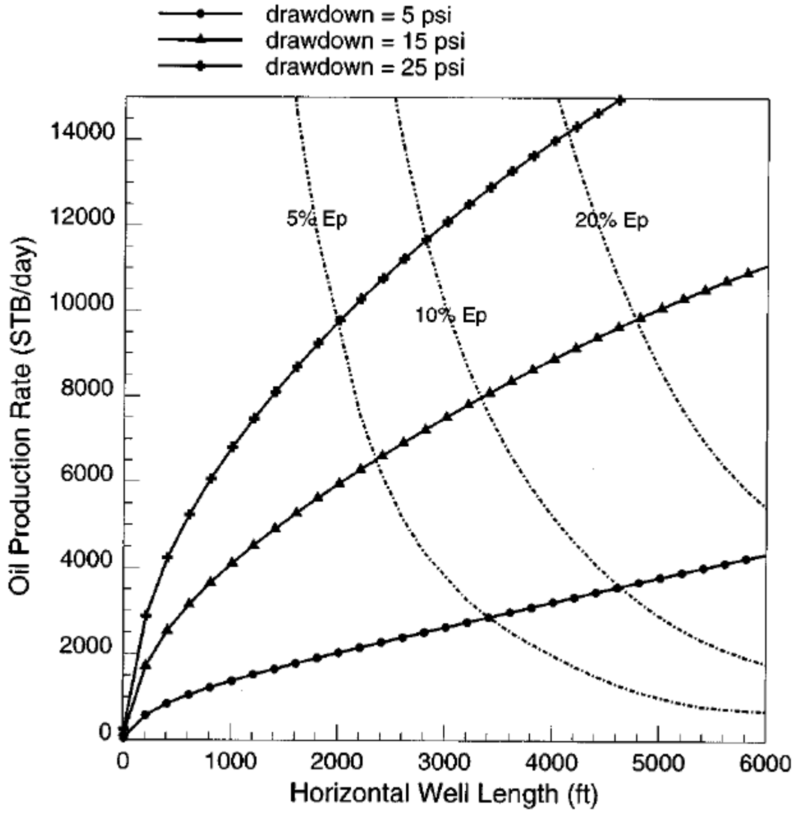


Figure 2.3: Relationship between well length, flow rate and wellbore pressure loss (Penmatcha et al. 1999).

2.2 Well Inflow Control

2.2.1 Inflow control devices

In order to improve the HW productivity, different well control completions are used. Li et al. (2011) explore the role Inflow control devices (ICDs) play in balancing the well inflow as shown in Figure 2.4 by creating an additional pressure drop. Jansen (2003) and Permadi et al. (1997) discuss use of stinger completion in which a pipe of smaller diameter than the liner is inserted along the horizontal part of the well, Figure 2.5. This splits the well into two shorter well segments reducing the pressure drop along the wellbore. In this work ICDs are investigated.

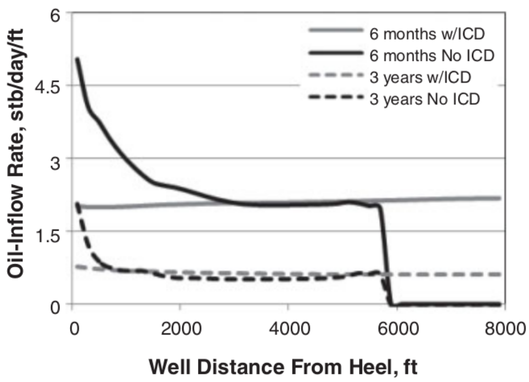


Figure 2.4: Oil inflow profile balanced along wellbore with ICD completion (Li et al. 2011).

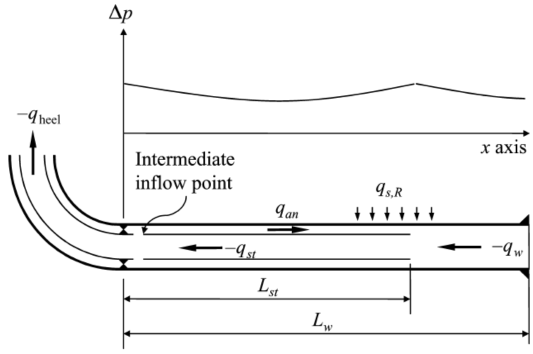


Figure 2.5: Stinger completion balancing draw down along well with intermediate inflow opening (Jansen 2003).

ICDs are described as chocking devices added to the completion section of the well with packers installed in the annulus to channel flow through the ICD. They balance the well inflow profile by creating an additional pressure drop on the sand face at a specified flow rate chocking the high productivity zones (Li et al. 2011; Lim et al. 2017). This balances the inflow contribution along the wellbore, giving a more balanced water and or gas front, reducing conning effects, such that the total oil recovery is improved. The term ICD strength is used to refer to the additional pressure drop applied by the ICD.

The channel and orifice type of ICDs as seen in Figure 2.6 are the most commonly used ICDs. They are present in different configurations, but have similar modes of operation. The channel type uses surface friction to generate the additional pressure drop with the fluids flowing through multiple layered screens before entering the wellbore. As friction pressure loss increases with flow rate, the device will be viscosity dependent, as seen from the Darcy flow equation defined in Equation (2.7). This dependency means that the ICD strength will change when water begins to flow in the well eventually reducing the effectiveness of the device (Daneshy et al. 2012).

$$q = \frac{k}{\mu}\frac{\Delta P}{L} \tag{2.7}$$

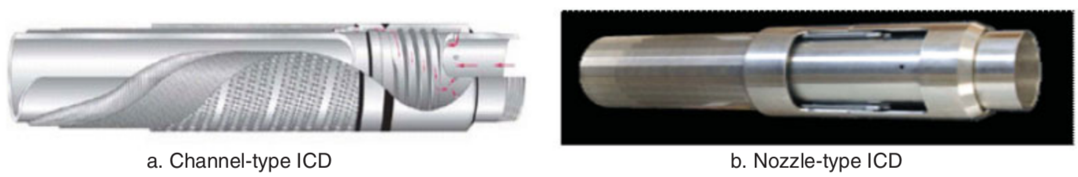


Figure 2.6: Channel (left) and orifice (right) type ICDs (Li et al. 2011).

With the orifice type the local additional pressure drop is created by a set of small diameter orifices, thus its performance is dependant on fluid velocity. This makes the ICD more susceptible to erosion (Li et al. 2011). The total pressure drop across the ICD is the sum of the pressure drop across the outer screen, conduit below the screen, the chamber, the orifices and the casing perforations, as indicated in Figure 2.7. Denney (2010) states that the orifices contribute 99.76% of the total local pressure drop, and that the flow through the ICD will vary with density as the flow through the orifices is turbulent.

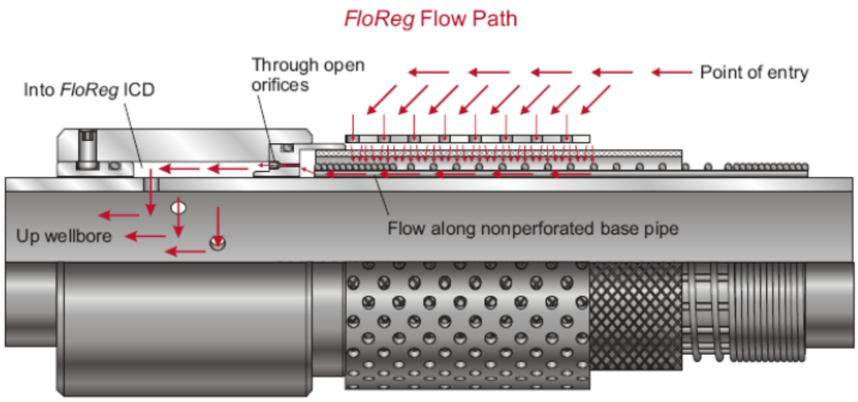


Figure 2.7: Illustration of flow of reservoir fluid through an orifice type ICD (Denney (2010)).

The ICD types described above are categorized as Passive Inflow control devices (ICDs) because once installed in the well, the strength of the ICD can not be adjusted to match the changing reservoir conditions (Al-Khelaiwi et al. 2010). This reduces the degree of freedom of the completions, making real time reservoir management difficult.

On the other hand are the Autonomous inflow control devices (AICDs), which adjust the additional pressure drop applied depending on the properties of the fluid passing through the device. An example is the fluidic diode AICD that makes adjustments depending on the fluid viscosities. The AICD design is such that the low viscosity water and gas is made to flow through a higher resistance pathway, thus effectively reducing its production, while the higher viscosity oil will flow through the path of least resistance, effectively encouraging it's production (James and Hossain 2017).

Li et al. (2011) discuss the impact of ICD on the horizontal well performance using two cases. Case 1 is a high permeability reservoir with an 8,000 ft long HW and Case 2 is a reservoir with moderate permeability with a 4000 ft long HW. The parameters for the cases described are listed in table Table 2.1. In both cases the wellbore is broken into 200ft segments each with an ICD installed. For Case 1 the ICD installation balanced the flow profile along the well bore as shown in Figure 2.4 and improved the total oil production as shown in Figure 2.8.

For Case 2, ICD installation lowered the oil-inflow rate resulting into a lowered cumulative oil production as as shown in Figure 2.9. In this case the friction pressure loss along the wellbore is minimal compared to the draw down of 400 psi such that the flow profile along the wellbore length with and without ICDs is the same. Use of ICDs to balance well inflow profile in this case is not beneficial. This shows that understanding the reservoir properties plays a role in the effectiveness of ICDs.

	Units	**Case 1**	**Case 2**
Reservoir Thickness	ft	100	120
Reservoir dimension	ft x ft	2,000 x 8,000	2,000 x 4,000
Well Length	ft	8,000	4000
Horizontal Permeability	md	800	50
Vertical Permeability	md	80	5
Average reservoir pressure	psi	2,930	2,950
Well-flow pressure at heel	psi	2,650	2,550
Oil Viscosity	cp	2	2
Oil density	lb/ft^3	40	40
Tubing diameter (ID)	in.	4.5	5.5
Water density	lb/ft^3	63	63
Number of ICD	-	40	20

Table 2.1: Input Parameters for ICD Study Case

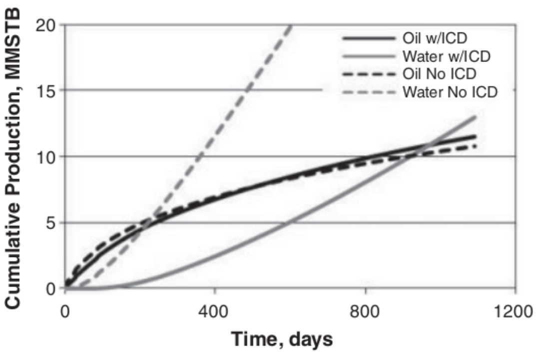


Figure 2.8: Increased oil production and delayed water breakthrough in Case 1 when an ICD is used (Li et al. 2011).

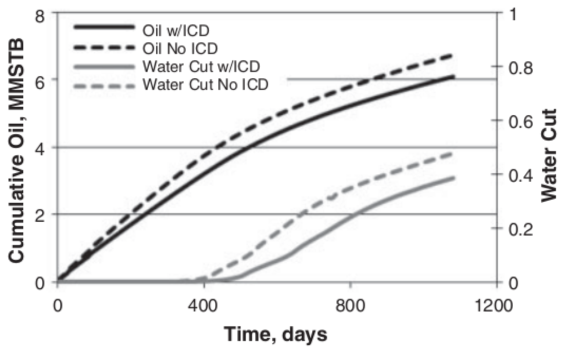


Figure 2.9: Reduced cumulative oil production with ICD coupled with reduced water production in Case 2 (Li et al. 2011).

2.2.2 Inflow Control Device design

The major aim of the design of ICD installation is to create a uniform flux along the length of the well with the desired effect being delayed water and gas breakthrough and improved oil recovery (Daneshy et al. 2012). Using an example of a HW in a homogeneous reservoir whose well in flow flux is U shaped as shown in Figure 2.10. The heel and toe of the well have a higher production rates on account of having a larger reservoir contact area. Deploying ICD along such a well to create a uniform flux would be detrimental to oil recovery as it requires chocking the heel and toe regions of the well and also lead to water breakthrough in the middle sections of the well.

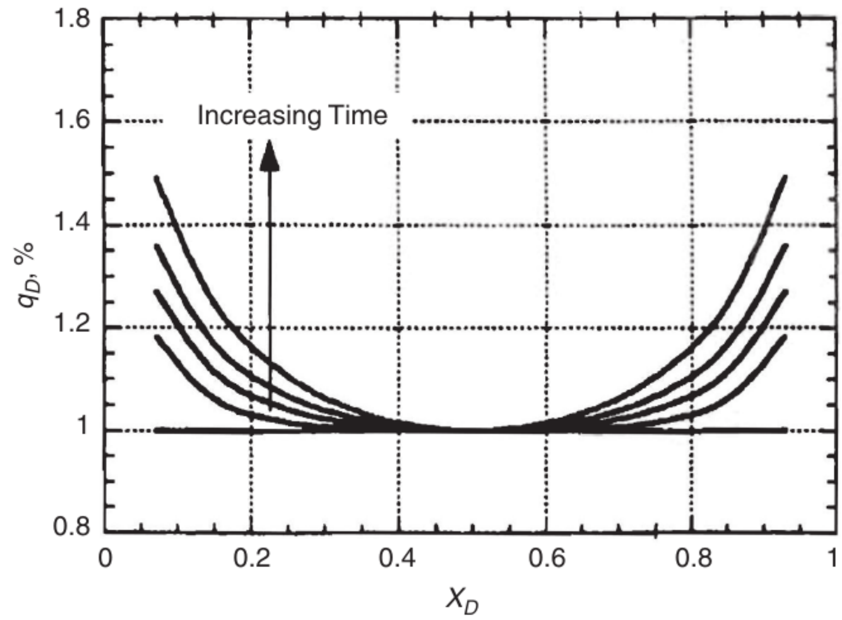


Figure 2.10: U-Shape flux profile along horizontal wellbore in homogeneous reservoir (Daneshy et al. 2012).

Daneshy et al. (2012) put forward a new ICD design philosophy which addresses early water, and gas breakthrough due to heterogeneous permeability, and uneven wellbore pressure caused by friction losses along the well. The ICD design suggested is to locally resolve the well inflow issues caused by reservoir permeabilities and frictional losses while allowing the rest of the well flow naturally. Below the two issues guiding the ICD design are discussed:

- **Heterogeneous Permeability:** HWs encounter varying permeabilities along their length as seen in Figure 2.11. The well sections with higher permeabilities will have higher production rates and thus be sites of possible early water breakthrough. These are the well sections that would require chocking to delay the water and gas breakthrough.
- **Well bore frictional pressure losses:** For long HW,the reservoir draw down reduces from the heel to the toe. This leads to higher production rates at the heel than the rest of the well. Balancing the flux would require chocking the heel section of the well reducing production from the connected reservoir region.

This design's main objective is to optimize the cumulative oil production before water and gas breakthrough by determining the appropriate ICD strength required for each of the sections. In the ICD design process, a first simulation is run where the natural flux along the length of the well is calculated using the reservoir fluid and formation properties. The natural flux along the well is represented by the green bars in Figure 2.12. The HW is then divided into multiple segments based on the permeability distribution along the well as depicted in Figure 2.11). The strength of the ICD required in order to obtain the desired flux from each well segment is calculated. Different ICD strengths scenarios of the available ICDs are run and the most appropriate that best suits the needs of the reservoir is selected. This example highlights the trial and error basis of such ICD design procedures.

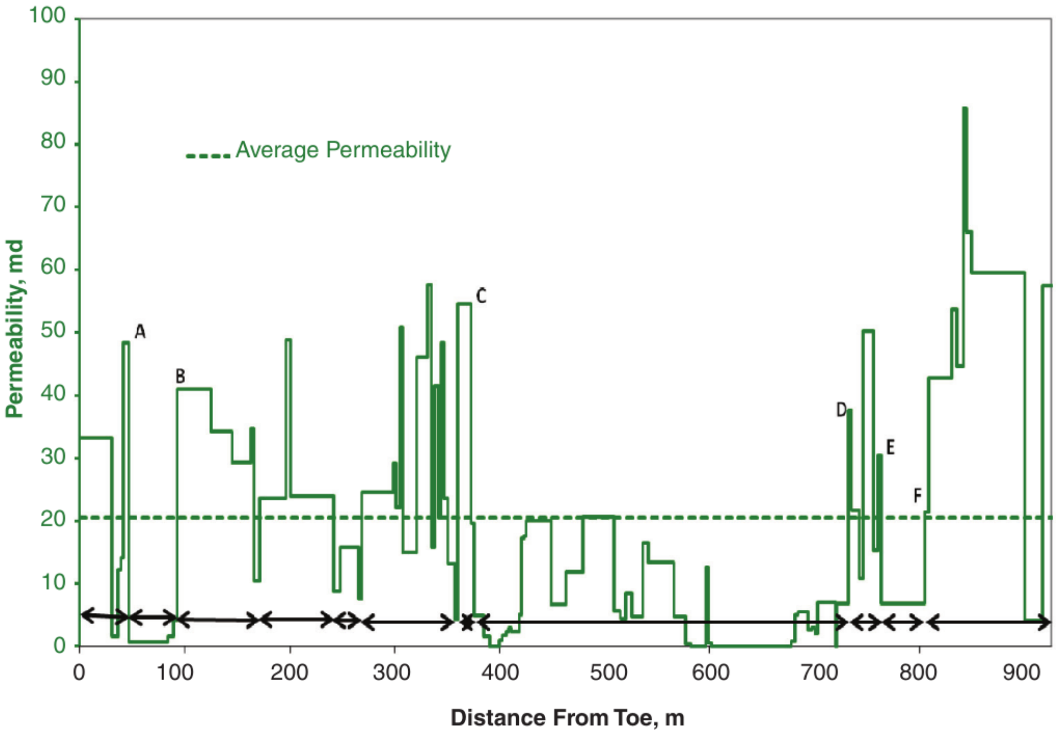


Figure 2.11: Permeability distribution along length of well ((Daneshy et al. 2012)).

A study case is used to show the working of this process. In Figure 2.12, the well has a U-shaped flux along the wellbore length when well is allowed to flow naturally. The computed choked flux is shown in the blue bars and the brown bars show the flux level after ICD installation. In Figure 2.12, water breakthrough will still occur at the heel, toe and mid section segment at 165m as there is a difference between the blue and brown bars. This difference shows that at the computed ICD strength, the ICD was not able to provide the desired chocking level and thus a new strength can be simulated.

A comparison was made with a commercial ICD design process in which the ICD segments were chosen as in Figure 2.13a, the resulting flux profile is shown in Figure 2.13b. In Figure 2.14, it can be seen that using the targeted design the total oil production goes up to 700,000 std/m^3 while using the commercial design a total oil production of about 400,000 std/m^3. From this it is clear that a targeted ICD design is more beneficial.

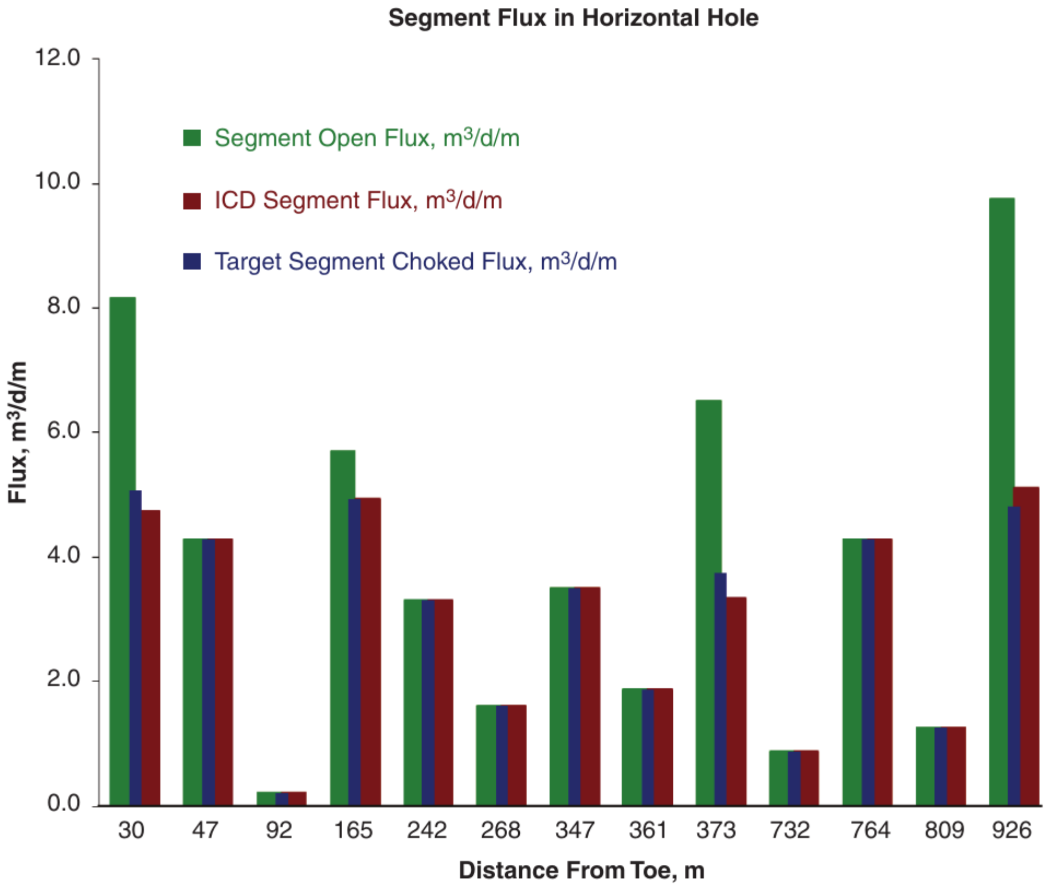
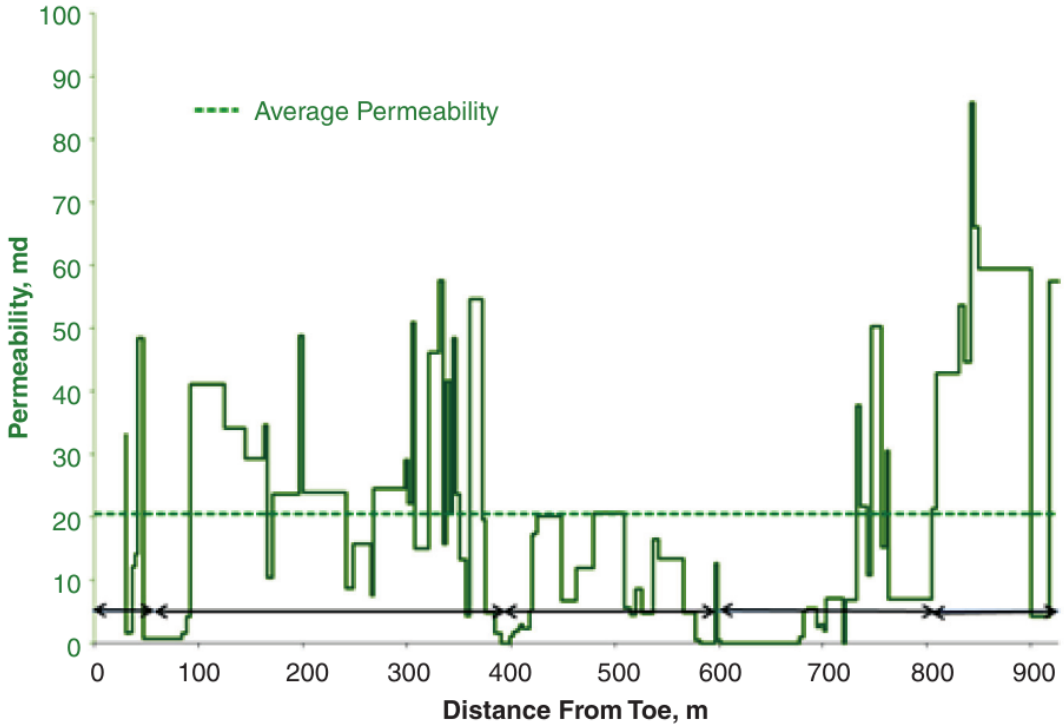
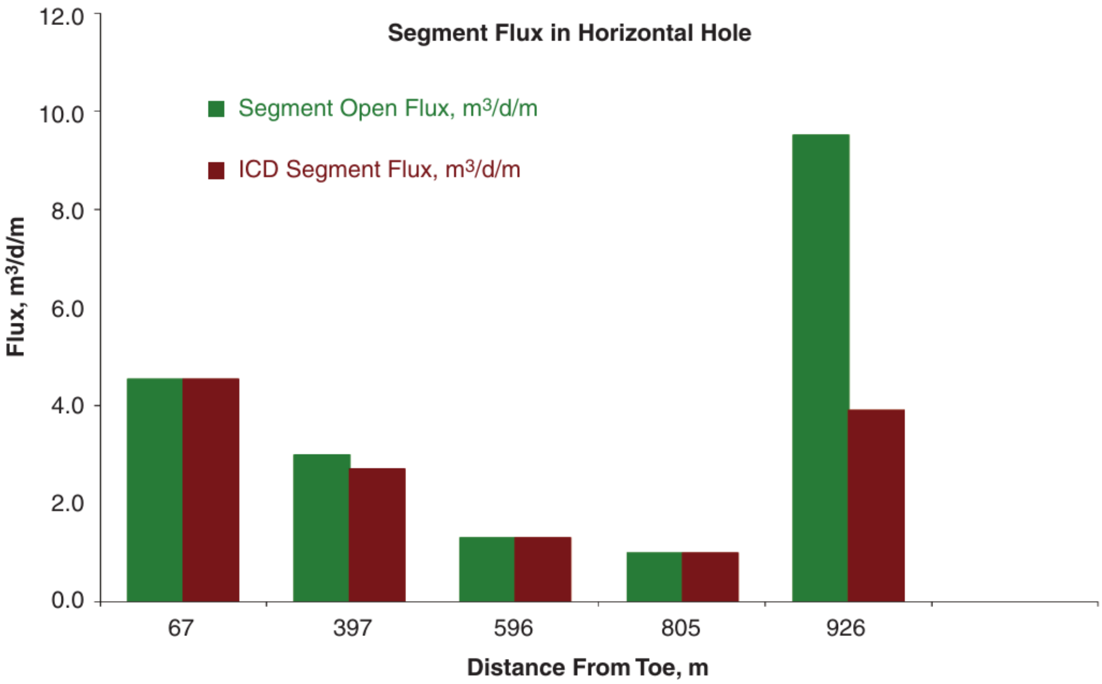


Figure 2.12: Flux profile across segments without ICD(green) and with ICD(brown) (Daneshy et al. 2012).

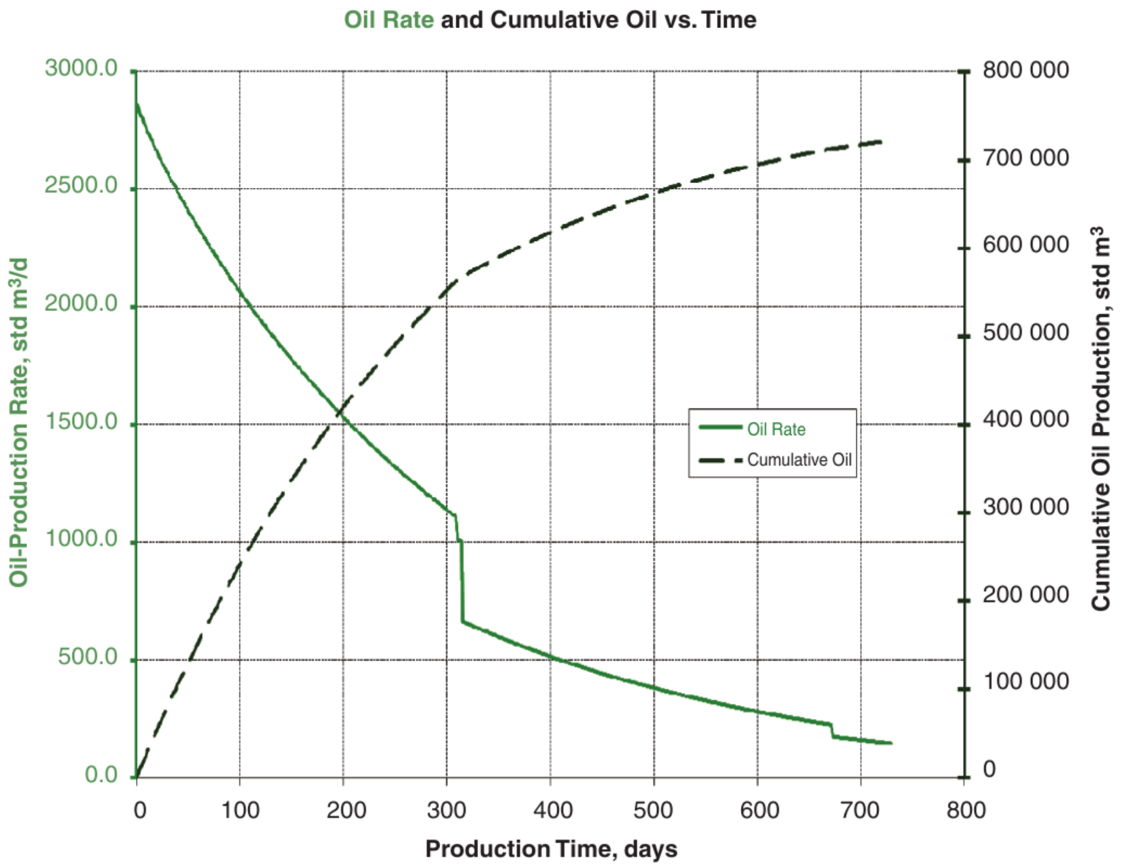


(a)

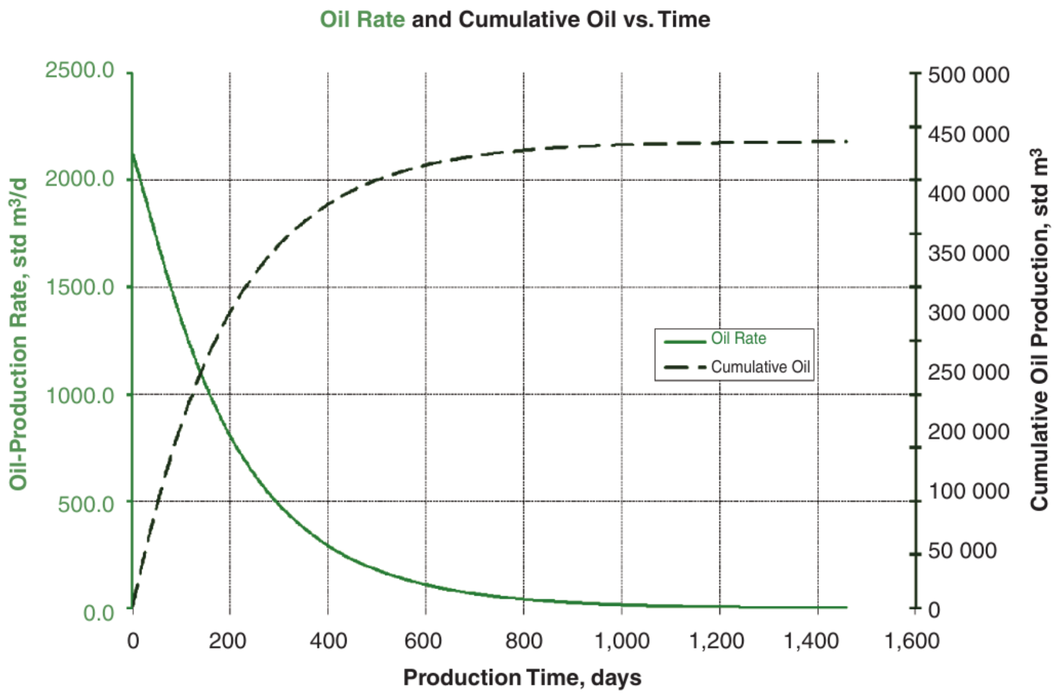


(b)

Figure 2.13: (a)ICD segment selection based on commercial ICD design. (b) Resulting flux profile along well with a commercial ICD design (Daneshy et al. 2012).



(a)



(b)

Figure 2.14: (a) Production result using targeted ICD design. (b) Production result using a commercial ICD design (Li et al. 2011).

The ICD design process described and evaluated in this work takes on a similar targeted approach, where the optimum pressure setting in each individual segment along the well that maximizes the objective is determined. As the design process involves optimization, the section below discusses several optimization methods applicable.

2.3 Well Control Optimization

Field development procedures are aimed at optimizing hydrocarbon production from any given field. These procedures involve; but are not limited to, determining the appropriate well placement and well controls. The optimal well placement and controls can be determined sequentially or in a joint manner. Bellout et al. (2012) discusses and compares both modes of optimization. In this work the well placement is fixed and only well controls are optimized.

Well control optimization is the determination of the optimum well control variables that are required to maximize a given objective function such as the Net present value (NPV) or cumulative oil production or minimize objective functions such as cumulative water production (Ciaurri et al. 2010). This optimization problem is in practice also constrained by other field operating factors such as daily production rates that have to be satisfied.

In this work the objective function of the optimization is the NPV and Bottom hole pressure (BHP) is the control variable. The optimization is constrained by the well liquid daily flow rates to account for topside production constraints. The objective function is computed from the results of the numerical simulation of fluid flow in the reservoir using the FLOW reservoir simulator. The results of the numerical solution will vary with variations in the optimization variable.

Optimization can be achieved using gradient based methods as discussed in Bellout et al. (2012), with a single objective function evaluation requiring one reservoir simulation which can be computationally costly (Wang et al. 2019). The objective function derivatives can be estimated numerically, but such calculation is costly and not accurate (Ciaurri et al. 2010) . Additionally these gradient based methods are likely to get stuck at local optima (Wang et al. 2019) or search in the wrong direction due to inaccuracies in calculating the derivatives when adjoint based methods are used (Echeverra Ciaurri et al. 2011).

For ease of optimization computation, derivative free optimization methods are chosen for the optimization problem to be solved in this work as discussed in Ciaurri et al. (2010), Echeverra Ciaurri et al. (2011), Isebor et al. (2014) and Wang et al. (2019). The direct search methods do not explicitly use the objective function's derivatives, hence the term derivative free methods/algorithms. They involve the sequential examination of trial solutions, comparing each solution with the best obtained up to that point, together with a method of obtaining what the next trial solution will be (Kolda et al. 2003). These methods are subdivided into Deterministic and Stochastic methods.

Deterministic methods use a defined pattern to search the space using an initial guess of the variable. They are also known as local derivative free search methods as they tend to get trapped at a local optima as the outcome depends on the initial guess given. As the method uses a defined pattern it will give the same result for different trial runs given the same initial guess (Wang et al. 2019). An example of such methods is the General Pattern Search method (GPS) or commonly known as the Compass Search method in which, as the name suggests a compass pattern is used to search the space as seen in Figure 2.15. The algorithm searches in all compass directions for trial solutions, moves to new point with better result than the current, if no better result is found, the step length is contracted and the search continues until set minimum step length is reached.

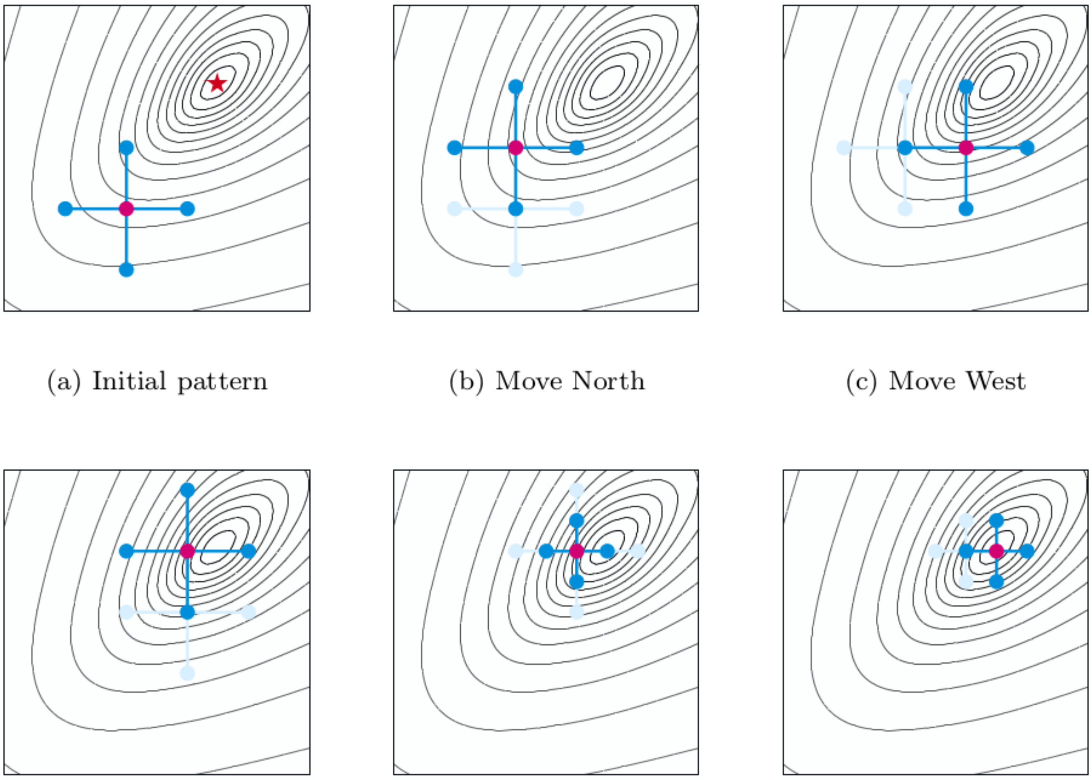


Figure 2.15: Description of the compass search method (Kolda et al. 2003).

This algorithm can be executed in parallel mode as function evaluations are made over a set pattern of points, together with a set of rules on how the points are updated. The function values at these points can easily be calculated individually and thus collectively at the same time in which case the method is known as the Parallel Pattern Search (PPS). The algorithm is described in Hough et al. (2001).

From Hough et al. (2001), it is seen that for the case of the PPS method the evaluation of the objective function in the different pattern directions and determination of new search point occurs concurrently. This means the method will have to wait for all function evaluations to be complete before making an assessment to move forward. In the case of Asynchronous parallel pattern search (APPS), the objective function evaluations in each direction will continue ahead concurrently in similar manner as to the PPS, but at each maximization point the individual processes will take into account only that information from the other processes that is available and continue searching until each individual process converges.

Stochastic methods are defined in Wang et al. (2019) as those that use the information from the previous trial solution and a random component to generate new search points. They are grouped as global direct search method as they search the entire search space at each evaluation. They are thus able to avoid being trapped in a local optima point but require more computational power. An example is the Particle Swarm Optimization (PSO).

PSO is a population based method that mimics the interactions of social animals such as birds to search for the optimum. As shown in Figure 2.16, at a given iteration the collection of the individual (Np) "particles" make up a swarm, with each member being a representation of a possible solution (E.Nwankwor 2013). The particles in the swarm move through the search space based on the information about the best solution found at each iteration by the particle; cognitive learning factor (c1), and the best solution obtained by any particle so far, social learning factor(c2).This information is updated for each particle at the end of the iteration to determine the new position ($\mathbf{x}$(k)) and velocity ($\mathbf{v}$(k)) of the particle (E.Nwankwor 2013). The process continues until the maximum number of iterations (K) have been attained as indicated in Figure 2.16.

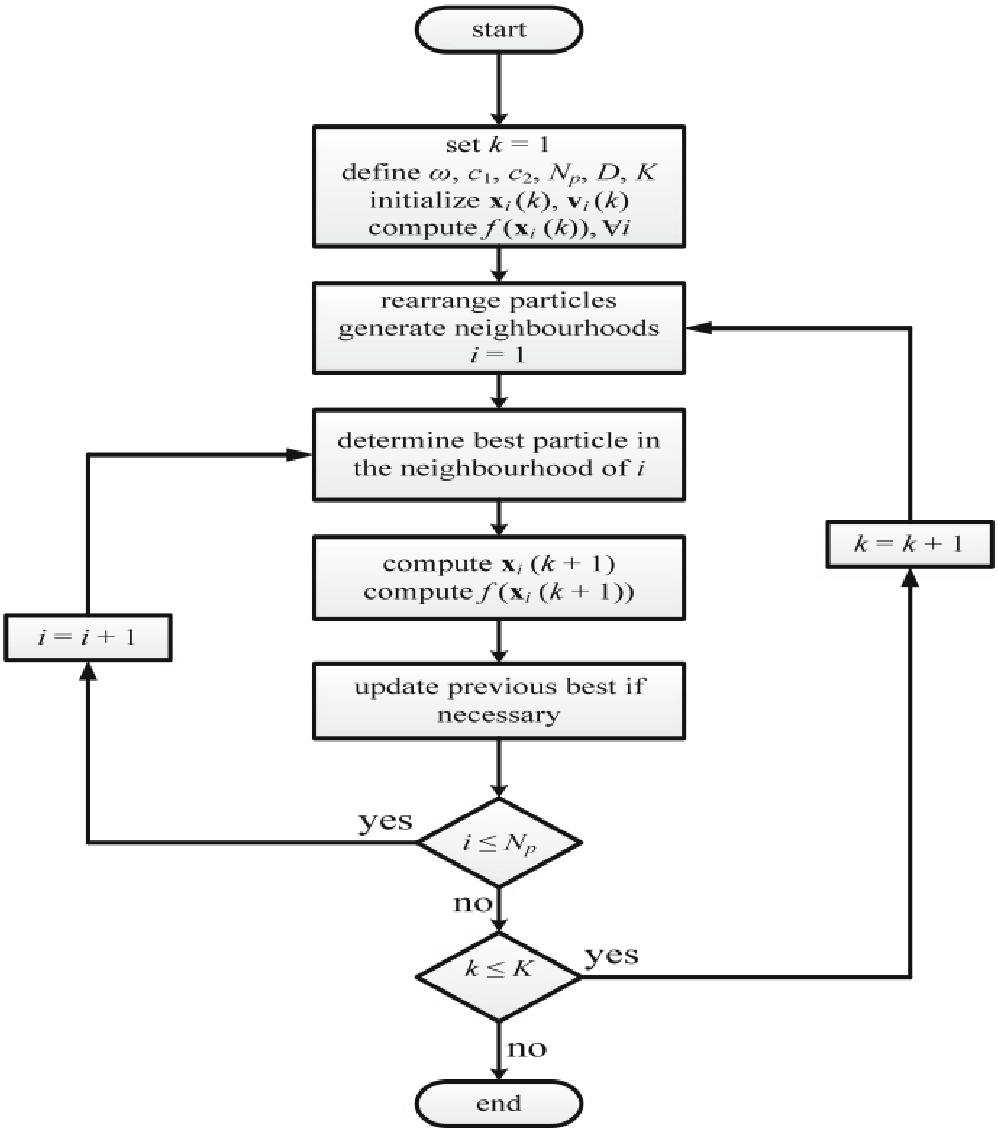


Figure 2.16: Flow chart of the PSO algorithm (E.Nwankwor 2013).

Chapter 3

Methodology

In this chapter a workflow is proposed, its development and automation are discussed. The aim of the workflow is to determine the optimal pressure distribution along the well path. The method used to translate the optimal pressure distribution to ICD strength settings is presented. Figure 3.1 is an overview of the workflow.

Starting with initial well coordinates, the production well is divided into a number of individual well segments. The Bottom hole pressure (BHP) for each well segment is optimized with respect to maximizing the Net present value (NPV). In this work, due to computational constraints the number of ICDs and their placement shall be consistent with well segments. Each well segment will be representative of a well compartment containing a single ICD. The final output of the workflow is therefore a number of well segments and the optimized pressure distribution along each segment.

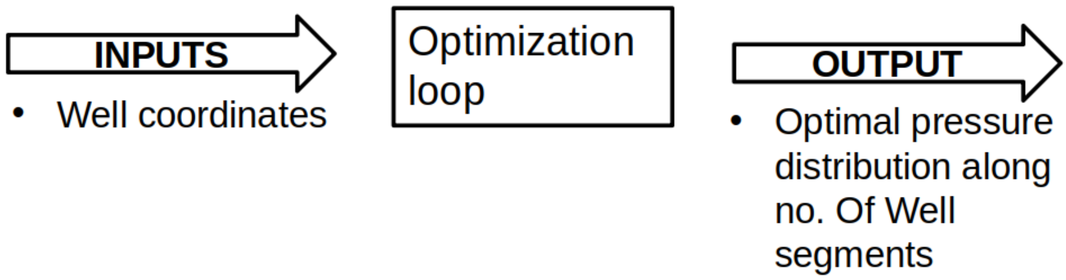


Figure 3.1: Visual of proposed general ICD settings design workflow.

3.1 Proposed Workflow

In a well completion, the ICDs are placed in compartments separated by packers for pressure isolation. This channels flow through the ICDs and prevents cross flow between the well compartments (Todman et al. 2017). The well is divided into multiple well segments to represent the ICDs. The well segments are modelled as individual wells of equal lengths so as to individually control each well segment pressure setting in a similar manner to ICD operation. Well segments of equal lengths and spacing are used in this work basing on the results from Todman et al. (2017), where the packer placement in ICD design had a small effect on the results, in addition to simplifying the setup.

For a given number of well segments, the optimal BHP of each well segment that maximizes the NPV is determined. The optimization problem being solved at this step is discussed in Section 3.1.2. The well control optimization step of the workflow uses FieldOpt software which is an open source software with various optimization methods including CS, APPS and PSO (Baumann et al. 2020).

The workflow is visualised as a set of two nested loops, with the outer loop being the well partitioning and the inner loop being the optimization of the NPV as illustrated in Figure 3.2. In the outer loop the well segments are modelled and in the inner loop the BHP settings for each of the well segments for which the NPV is maximum are determined. The number of well segments corresponds to the number of ICD and the optimal BHP control settings will give their corresponding strength i.e. the required pressure drop across the ICD.

In the inner optimization loop, the number of well control time steps; n_s, are increased in a step wise manner until there is no more increase in the NPV or the set maximum number of control time steps; n_s^m, is reached. At each step the optimization results of the previous step are used as the initial guess for the next optimization step with increased number of control time steps. The number of segments the well is divided into is increased in the outer loop of the workflow and the inner loop is repeated for the new number of well segments. The workflow continues until there is no more increase in the NPV_{nw}. In this work the workflow was continued until the maximum number of well segments n_w^m are attained.

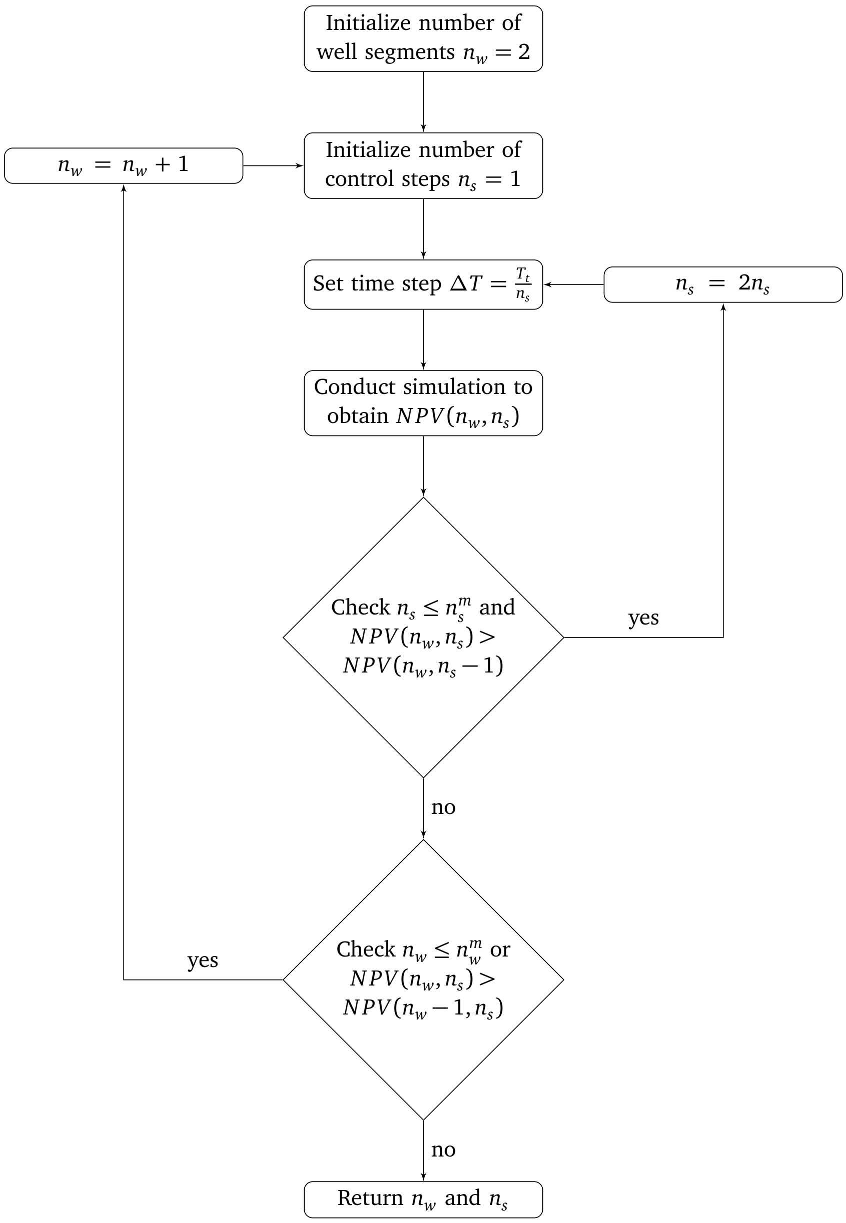


Figure 3.2: Illustration of the proposed workflow.

Where:

- n_w : number of well segments.
- n_s : number of well control time steps.
- : NPV_{nw} : NPV w.r.t the number of well segments.
- $NPV_{nw,ns}$: NPV w.r.t to a given number of well segments and number of well control time steps.
- n_w^m and n_s^m: Maximum number of well segments and well control time steps respectively.
- Δ T: duration of control time step.

3.1.1 Well Partitioning

As described in Section 3.1, the first step of the proposed workflow is to divide the production well into a number of well segments using the function in listing Code listing 3.1. The function requires the heel and toe coordinates of the well, the number of well segments and the spacing between the well segments as the inputs.

In order to avoid wells penetrating the same cell during modelling, a spacing of half the grid cell size and the coordinates of the grid cell faces are used as input coordinates. These are tabulated in Section 3.2. Note that the total effective production length of the well segments differs from that of the initial well as the well segments are modelled with spacing between them to prevent the wells from penetrating each other. In this work the number of well segments the well is divided into is done in multiples of two.

```
#Partitioning wells function
def split(start, end,segments,spacing):
#spacing usually model cell size to avoid wells penetrating the same cell
    for jj in range(0,np.size(start)):
        #size of input coordinates
        x_delta = (end[jj] - start[jj]+2*spacing) / float(segments)
        #z_delta = (end[jj+2] - start[jj+2]) / float(segments) #for deviated wells
        z_delta = 0 # for horizontal wells
        points = []
        for i in range(0, segments):
            points.append([start[jj]-spacing+i*x_delta+spacing,start[jj+1],
            start[jj+2]+i*z_delta,start[jj]-spacing + (i+1) * x_delta-spacing,start[jj+1],
            start[jj+2] + (i+1) * z_delta])
        return points
```

Code listing 3.1: Function for partitioning well into given number of well segments.

For a horizontal well, the value of ΔZ is set to zero and for a deviated well the value of ΔZ is calculated with no spacing term. Figure 3.3 is an illustration of how the partitioning function divides the well into segments of equal length.

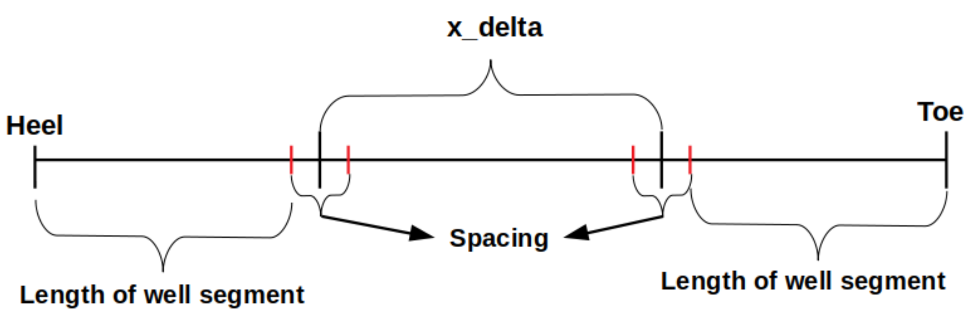


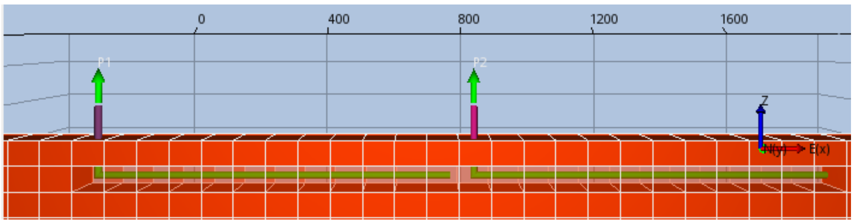
Figure 3.3: Illustration of how the well partitioning code divides a well into three well segments.

The x,y, z coordinates of the heel and toe for the well segments are generated with Code listing 3.1 and are saved as a csv text file in the format shown in Figure 3.4.

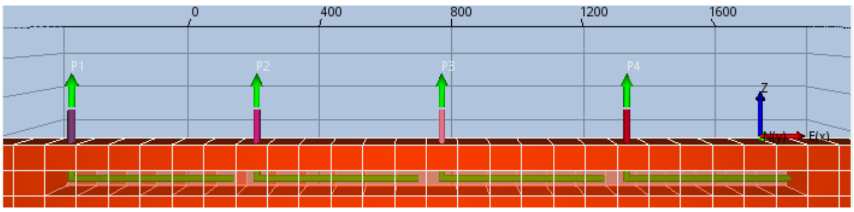
```
# x, y, z, x, y, z
425.0,730.0,2005.0,608.3,730.0,2005.0
633.3,730.0,2005.0,816.7,730.0,2005.0
841.7,730.0,2005.0,1025.0,730.0,2005.0
```

Figure 3.4: Example of heel and toe coordinates generated for the three well segments.

Using the generated coordinates, the new wells are modelled with the help of the Well index calculator (WIC). The WIC is a program embedded within FieldOpt software that generates the well specification and well completion data required by the reservoir simulator for well modelling. The well specifications describe the well name, group, wellhead location, reference depth for the BHP and fluid phase. The completion data describes how the well is connected to the reservoir. This data is generated by running a single optimization run in FieldOpt with the heel and toe coordinates of the desired wells input into the json file. Examples of the possible well partition configurations are shown in Figure 3.5.



(a) Well divided into 2 well segments.



(b) Well divided into 4 well segments.

Figure 3.5: Possible well partition configurations for a horizontal well.

3.1.2 Optimization

As discussed in Section 2.3, well inflow can be controlled with either rate or bottom hole pressure (BHP) settings. These well controls can then be optimized to maximize the NPV or oil production. The optimization seeks to maximize the NPV as a function of the BHP. The optimization problem can be defined as:

$$\text{argmax } NPV(u) = \{u \mid u_{min} < u_{max}, NPV(u) > NPV(v) \forall u_{min} < v < u_{max}\} \quad , \tag{3.1}$$

where u is the BHP variable constrained between the minimum and maximum BHP values u_{min} and u_{max}.

The BHP well controls are defined at given control time steps and held constant during that time interval but can vary at the next defined control time step. The objective function to be maximized is the yearly discounted NPV which is a direct function of the oil and water produced as represented by Equation (3.2) and well cost C_w.

$$NPV = \sum_{k=1}^{N_T} \frac{\left(\sum_{w=1}^{n_w} p_o q_o^k - \sum_{w=1}^{n_w} p_w q_w^k \right)}{(1+d)^k} - (C_w * n_w) \tag{3.2}$$

Where;

- T is the of production period in years
- q_o and q_w are the total oil and water produced in the production period k respectively.
- p_o is the price of oil.
- p_w is cost of water produced.
- d the discount factor.
- C_w is a constant well cost for each well segment to represent the cost of ICDs.

The NPV components used in the optimization step of the workflow are tabulated in Table Table 3.1. The components used in the NPV calculation are the same for all the study cases. The maximum of the optimization variable BHP, is set to 140 barsa to avoid well shut in during optimization.

NPV Components	value
Oil Price	60$/bbl
Cost Water Produced	24$/bbl
Discount factor	0.08
Well Cost	7.5 E4 USD
Minimum BHP	80 barsa
Maximum BHP	130 barsa

Table 3.1: NPV components used in the optimization step for cases.

3.1.3 Automation of Workflow

The workflow described above is automated Code listing A.4 written in Python. The code is executed with an input file shown in Code listing A.5 in which the different inputs are declared, both scripts can be seen at `https://github.com/marinaki15/OptimalWellInflow`. The inputs declared are:

- Number of well segments.
- Well partitioning inputs: heel and toe well coordinates and spacing.
- PROJECT_PATH: Working directory.
- INITIAL_MODEL: Path to initial model case.

- FINAL_MODEL: Path to new model with well segments.
- OPT_OUTPUT: Optimization output folder.
- DRIVER_FILE: Directory to which JSON driver files are saved.
- Simulation period in years (T).
- Maximum number of control steps.

The first part of the Python code executes the outer loop of the workflow, that is starting with the initial model, heel and toe coordinates of the single well, spacing and number of individual well partitions to be modelled. These are declared in the input file. The code generates the heel and toe coordinates for the new wells, saving them in the text file coordinates.csv as comma separated values. The coordinates are read from the text file and written into the JSON driver file ; saved in the DRIVER_FILE folder. A single optimization evaluation is run in FieldOpt in order to generate the new well completion data. The new model is saved in the FINAL_MODEL file path.

The next part of the Python code executes the inner optimization loop. In this section the optimization algorithm parameters are tuned to match the increase in number of optimization variables. For the PSO method used in this work, the Swarm size is tuned to be a product of the number of well segments and the Maximum number of Evaluations is a product of the number of well control time steps being optimized.

The JSON driver file requires that all the simulation time intervals are declared in the control times tab seen in Code listing 3.2. These are generated by the short function Code listing 3.3. As described in Figure 3.2, while the number of control steps is less than the set maximum, the code splits each control time step into two time intervals. The control step refinement process is executed in the while loop until the maximum number of control steps are reached. At each control time step refinement step, the initial BHP values in the JSON file are updated using the BHP values from the previous optimization step. After fully editing the JSON file, the optimization output folder is created and the optimization is initiated.

```
"Global": {
    "BookkeeperTolerance": 1e-08,
    "Name": "1WSHOEBOXMODEL"
},
"Model": {
    "ControlTimes": [
        0,
        365,
        730,
        1095,
        1460,
        1825,
        2190,
        2555,
        2920,
        3285,
        3650,
        4015,
        4380
```

```
    ],
    "Reservoir": {
        "Type": "FLOW"
    },
}
```

Code listing 3.2: Control Times tab where all control times are declared in JSON file.

```
def Timesteps (years,steps):
    Timesteps =[]
    T_delta = (years*365)/steps
    for i in range(0,(steps+1)):
            T = round(i*T_delta)
            Timesteps.append(T)
    return Timesteps
```

Code listing 3.3: Function for generating time steps for JSON file.

3.2 Synthetic Models

In this section different Simple synthetic "Shoe-box" reservoir models are used in this work to study the performance of the workflow for different scenarios. Case 1 is a model developed by Angga (2020) is used in the workflow development. The model is 60 X 60 X 20 3D model, with grid cell sizes in the X and Y direction are both 25m while the Z direction is 4m.

The model is a simple black oil reservoir supported by a connected aquifer, the phase behavior in the reservoir model is calculated using the black oil model and the PVT tables are obtained from the Olympus model ((R.M.Fonseca 2017)). The model is homogeneous with permeabilities in the x and y direction both being 100mD, and 10mD in the z direction. The reservoir has a porosity of 0.3. The reservoir top is set at 2000m and rock compressibility is $1.4234.10^{-5} barsa^{-1}$ at a reference pressure of 230 barsa. The oil water contact is set at 2060m, the aquifer is numerically modelled to be one thousand times bigger than the reservoir bulk volume in order to simulate effective aquifer support.

The homogeneous shoe box model is modelled with a single horizontal producer well 600m long as seen in Figure 3.6, the heel and toe coordinates of the well are in Section 3.2. The well has a wellbore diameter of 0.1905m. The well production is controlled with the bottom hole pressure together with a maximum Surface liquid rate of 5000 sm3/d 35 ay.

	X(m)	Y(m)	Z(m)
Heel	425	730	2005
Toe	1025	730	2005

Table 3.2: Horizontal Well Coordinates.

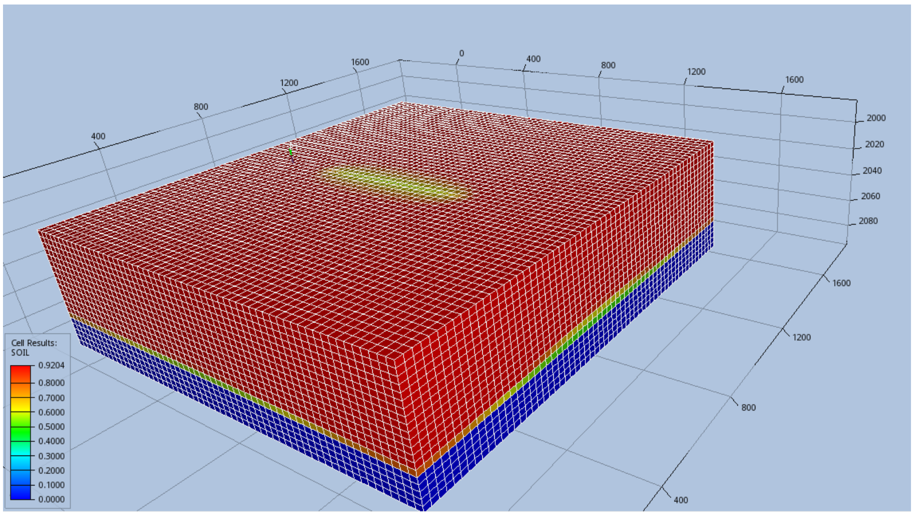


Figure 3.6: Case 1: Horizontal well in Homogeneous Reservoir

Case 2 is remodelled from the homogeneous Case 1 described above. Case 2 is a 3D heterogeneous reservoir model with permeability and porosity values used to model heterogeneity are taken from the SPE10Model2 using Code listing A.3. The porosity and permeability fields of the study case are shown in Figure 3.8 and Figure 3.9 respectively.

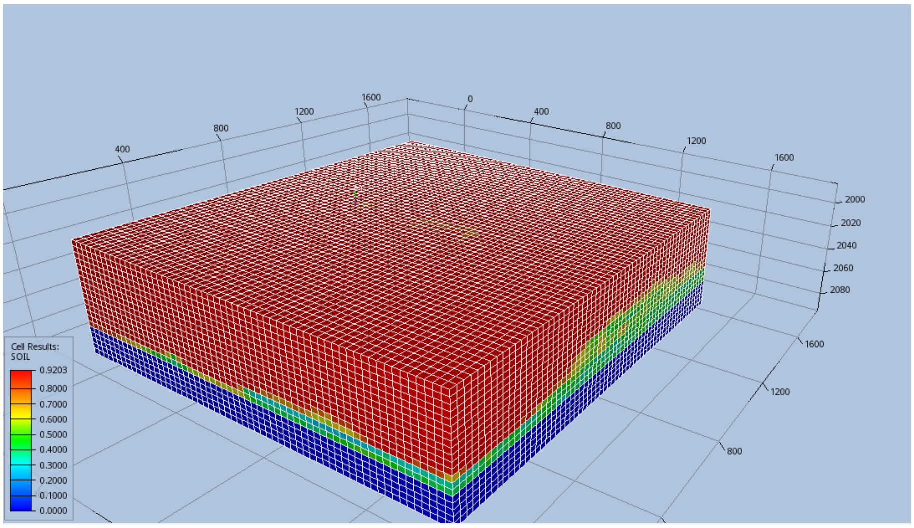


Figure 3.7: Case 2: Horizontal well in Heterogeneous Reservoir

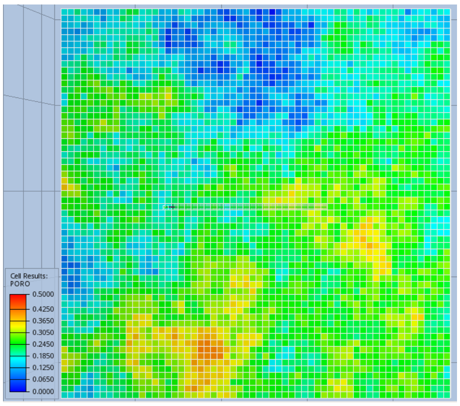


Figure 3.8: Porosity field of Case 2 of horizontal well in Heterogeneous reservoir

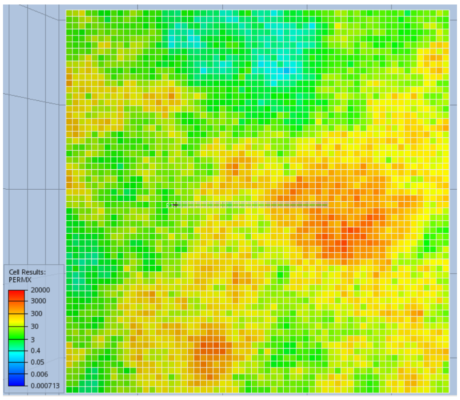


Figure 3.9: Permeability field of Case 2 of horizontal well in Heterogeneous reservoir.

3.3 Optimization Setup

In this section the optimization executed in the inner loop of the workflow is discussed. Using 2 well segments in Case 2, the surface of the optimization objective function is generated in order to examine the nature of the problem. The Particle swarm optimization (PSO) and Asynchronous parallel pattern search (APPS) optimization methods are compared to determine the most suitable for this work.

3.3.1 Nature of Optimization Problem

Using Case 2 with the horizontal well divided into 2 well segments as shown in Figure 3.10, the nature of the optimization problem to be solved in the optimization loop of the workflow is illustrated. The NPV surface is mapped to examine the nature of the objective function search space in which the optimization algorithm shall search for the maximum value.

The possible BHP combinations using a single control time step are limited within 80 and 150 bar, and a well group liquid rate constraint of 5000 sm3/day to account for surface facilities. For each BHP combination the model is simulated, the total oil and water production values are extracted and used to calculate the resulting NPV. Code listing A.1 in the Appendix is used to execute this.

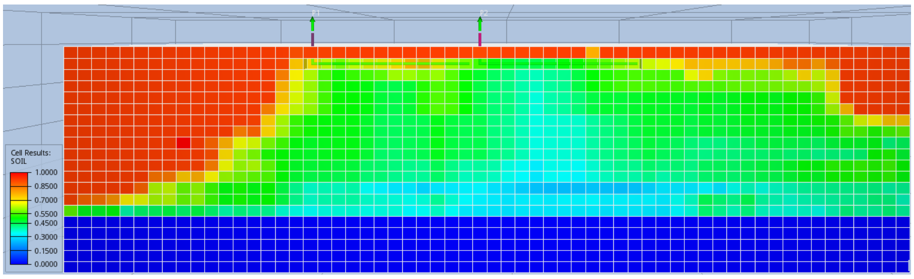


Figure 3.10: 2 Well Partition configuration used to study the nature of the optimization problem.

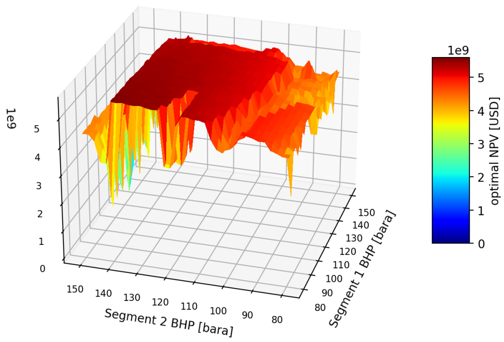


Figure 3.11: 3D Surface of the NPV for the 2 well configuration.

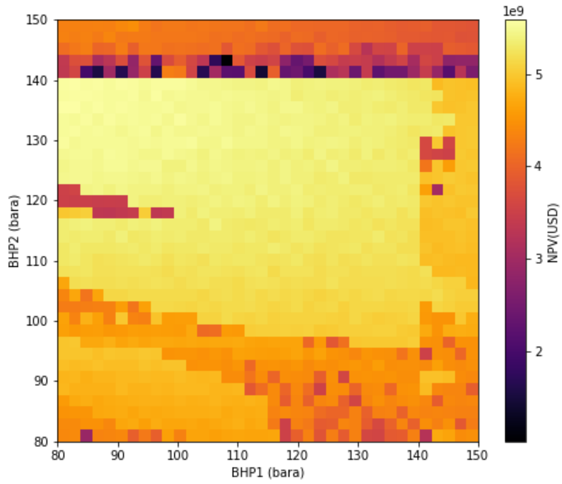


Figure 3.12: Contour plot of the NPV response surface shown in Figure 3.11.

Figure 3.11 shows that the objective function surface is fairly smooth within the given range of variable values. The sudden drops in NPV at BHP values higher than 140 bara is due to the wells being shut in during the production period. Figure 3.12 clearly shows the sharp decrease in NPV when the BHP is set to 140 bara in well P2 .

In the Flow simulator, producer well controls are specified under the WCON keyword. The well can be controlled by specifying the target surface fluid phase well production rate, surface liquid rate, BHP or well head pressure. In this work the well BHP is used and is defined by the simulator as the minimum BHP that the producer well can be set to. In our optimization case, well P2 is shut in when a BHP of 140 bara is set, as at that minimum BHP, the well cannot be produced under the prevailing reservoir conditions.

From Figure 3.11 and Figure 3.12, we can infer that the use of local search derivative free methods such as APPS require input of an appropriate initial guess to avoid getting stuck at a local maximum of the NPV present at the far right of Figure 3.11. In this case a global search method would be more effective irrespective of the initial guess given. Additionally we see that for this work, the range of the BHP optimization variables can be narrowed in order to avoid instances of the wells being shut in during the optimization process.

3.3.2 Bench Marking Optimization Algorithm

Section 2.3 discussed a few of the derivative free optimization algorithms that can be applied to solve the optimization problem. Using the 2 well configuration in case 2, the APPS and PSO methods are compared. The parameters used for each method are listed in Table 3.3. The methods are both given the same initial guess for the BHP. As the PSO method is stochastic in nature, the algorithm is run three times, and a final average value of NPV is obtained.

Table 3.4 shows that the PSO performs considerably better, but at a high computational cost with more than 1000 evaluations used as seen in Figure 3.14 as compared to the 29 for APPS as seen in Figure 3.13. The optimal BHP values obtained by both methods are listed in Table 3.5. The results from PSO gives values for each segment that are close to each other, conversely the APPS BHPs are significantly different in value for each segment.

APPS		**PSO**	
Parameter	value	**Parameter**	value
Max. Evaluations	1000	Max. Generations	25
Initial Step length	20	Learning factor1	2
Contraction factor	0.5	Learning factor	2
Expansion factor	1	Swarm size	72
Min. Step length	2	Velocity scale	2
Max. Queue size	4	-	-

Table 3.3: Parameters for Optimization method:APPS vs PSO.

From this analysis the optimization process of the workflow shall use the Particle swarm optimization (PSO) method with the parameters in Table 3.6.

3.3.3 Well Control Frequency

The results presented in Table 3.4 are a well control optimization at a single control time step at the start of the production period. The well controls are treated as "piece wise functions" (Oliveira and Reynolds 2014), where the control is held constant between each control time interval. For each well segment, the frequency with which the well control is varied that is the number of well control time steps, affects the outcome of the optimization. With a few

	APPS	**PSO**
NPV (USD)	8.85E8	9.11E8

Table 3.4: NPV results of the comparison.

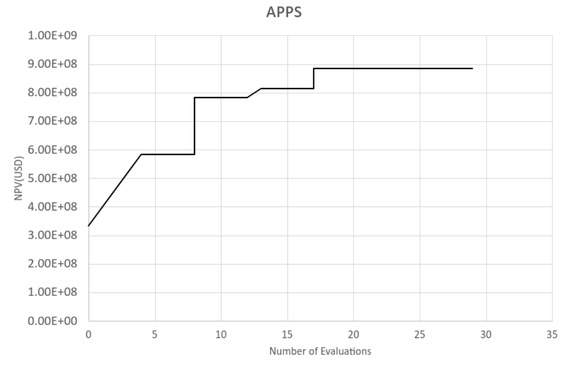


Figure 3.13: Computational cost of optimizing NPV using the APPS algorithm with only 29 evaluations used to reach convergence

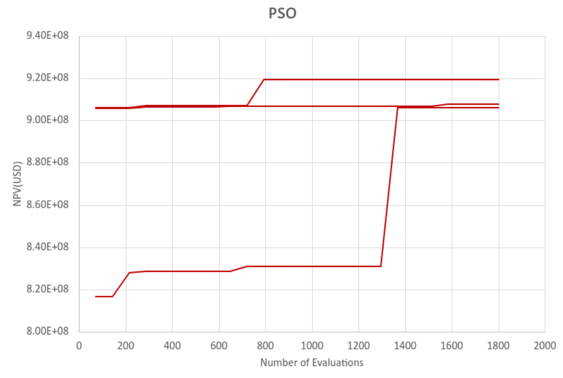


Figure 3.14: Computational cost of optimizing NPV using PSO algorithm showing considerable increase in the NPV

Bottom hole pressure (BHP)(Bara)	APPS	PSO
P1	97.5	135.054
P2	140	138.34

Table 3.5: BHP results of comparison.

control time steps, the optimization problem is faster to solve but may not give the optimal solution while too many control time steps increase the number of optimization variables and thus computational cost. That said, there is need to determine the appropriate well control frequency for each case number of times the well control can be varied during the production period.

Several techniques for determining the optimal number of control time steps are discussed in Oliveira and Reynolds (2014). One such technique is the multi-scale regularization as discussed in Wang et al. (2019) , Oliveira and Reynolds (2014) and Lien et al. (2008). This approach starts with few control time steps such that the control time interval is coarse. The control time interval is gradually refined by successively increasing the number of control time steps. At each refinement step the optimization solution from the previous coarser time interval

Optimization Parameters	value
Max. Generations	25
Learning factor1	2
Learning factor	2
Swarm size	(25*i)
Velocity scale	2

Table 3.6: For the Swarm size it is increased according to the number of well partitions i that are being optimized.

is used as the initial guess for the optimization at the next refined time interval. The process is stopped when the maximum number of control time steps have been attained.

In this work, the ordinary multi-scale or successive splitting as discussed in Lien et al. (2008) is applied. In this approach at each refinement step a single control time step is split into two new ones. The process is as follows:

1. Starting with one control time step for each well segment; $n_s = 1$, the number of optimization variables are thus equal to the number of wells.
2. Initial guesses for the BHP for each well segment are assigned and the optimization run.
3. The control time step is split into two steps of equal length, this doubles the number of optimization variables. The optimal solution from the single control time step is used as the initial guess , and step 2 is repeated.
4. The process is stopped once the maximum number of control time steps are attained.
5. The result is assessed and consecutive control time steps with similar controls are merged.

3.4 Software

Optimization is executed using FieldOpt software developed under the Petroleum Cybernetics Group (PCG) NTNU. The software is open source allowing for easy prototyping and testing different optimization scenarios such as well control optimization and well placement. Different optimization algorithms are available within FieldOpt such as Particle swarm optimization (PSO), Asynchronous parallel pattern search (APPS), Compass search (CS) and Genetic Algorithm. FieldOpt uses json files as inputs in which the different optimization parameters are described. Further description of the software is available at `https://github.com/PetroleumCyberneticsGroup/FieldOpt`.

In this work the reservoir modelling and simulations are executed using the Flow simulator, which solves the equation for fluid flow in porous media implicitly. Flow is a Black Oil simulator where only three components; water, oil and gas, are considered to be distributed among the three phases; aqueous, oleic and gaseous. Flow requires a .DATA file to execute the reservoir simulation. The different keywords their definitions and functions used for Flow in the .DATA input file are described in the Flow Documentation Manual available at `https://opm-project.org`. The reservoir simulation results are visualised in ResInsight. This is a 3D visualization tool part of the OPM project.

3.5 Translating Optimal Pressure distribution to Inflow Control Device settings

As described in section Section 3.1, the final output of the workflow is a number of well segments with optimal BHP settings that maximizes the NPV with respect to the number of well segments. In this section the method used to translate the optimal pressure distribution along the well segments to ICD settings is discussed. This method is not automated.

3.5.1 Modelling ICD

For each case, the result from the proposed workflow that gives the highest NPV shall be used to model the ICD completion along the Horizontal well. The flow reservoir simulator has the capability for modelling sub-critical valve type ICD and spiral type ICD. Both are types of frictional ICD where the pressure drop across the device is due to friction losses. In this work the sub-critical valve is modelled. It is a passive Inflow control device that creates the additional pressure loss by constricting fluid flow before it enters the production tubing.

Flow simulator calculates the pressure drop created by the device using the sub critical homogeneous flow through a constriction model. In this model the total pressure drop across the ICD, ΔP, is the pressure drop due to the constriction ($\Delta P_{constriction}$), and additional friction pressure loss in the segment containing the valve ($\Delta P_{friction}$). These components are calculated using the equations below

$$\Delta P = \Delta P_{constriction} + \Delta P_{friction} \tag{3.3}$$

$$\Delta P_{constriction} = C_1 \frac{\rho v_r^2}{2C_v^2} \tag{3.4}$$

$$\Delta P_{friction} = 2C_2 \frac{fL}{D} v_p^2 \tag{3.5}$$

where:

- Unit conversion factors:
  - $C_1 = 1.340x10^{-15}$
  - $C_2 = 1.0x10^{-5}$
- v_r = flow velocity of mixture through constriction (m/s)
- C_v = dimensionless flow coefficient for valve
- D = Diameter of pipe (m)
- f = fanning friction factor
- L = Length of segment (m)
- v_p = flow velocity of mixture through segment(m/s)
- ρ = Fluid mixture density (kg/m^3)
- P = Pressure (barsa)

The flow velocity of the fluid mixture through the constriction depends on its cross-section area such that:

$$Q = v_r A_r \tag{3.6}$$

where:

- A_r = Cross sectional area of constriction
- Q = volumetric flow rate (m^3/day)

Substituting equation 3.6 into equation 3.4 gives the $\Delta P_{constriction}$ as:

$$\Delta P_{constriction} = C_1 \frac{\rho Q^2}{2C_v^2 A_r^2} \tag{3.7}$$

The strength of the device; K, is defined by:

$$K = \frac{C_1}{2C_v^2 A_r^2} \tag{3.8}$$

We can thus define the $\Delta P_{constriction}$ as:

$$\Delta P_{constriction} = K \rho Q^2 \tag{3.9}$$

From the above equations the strength of the device K is given by equation 3.9.

$$K = \frac{\Delta P - \frac{2C_2 f L v_p^2}{D}}{\rho Q^2} \tag{3.10}$$

As per the description of the WSEGVALV keyword in the OPM Flow Manual, the ICD requires the cross sectional area of the constriction A_r in the modelling process. Section 3.5.2 describes the method used in this work to determine the value of A_r.

When completing a well with ICDs, the well is divided into compartments using packers placed in the annulus between the reservoir and production tubing as illustrated in Figure 3.15. In each compartment any number of ICDs can be placed to control the fluid flow into that compartment of the well.

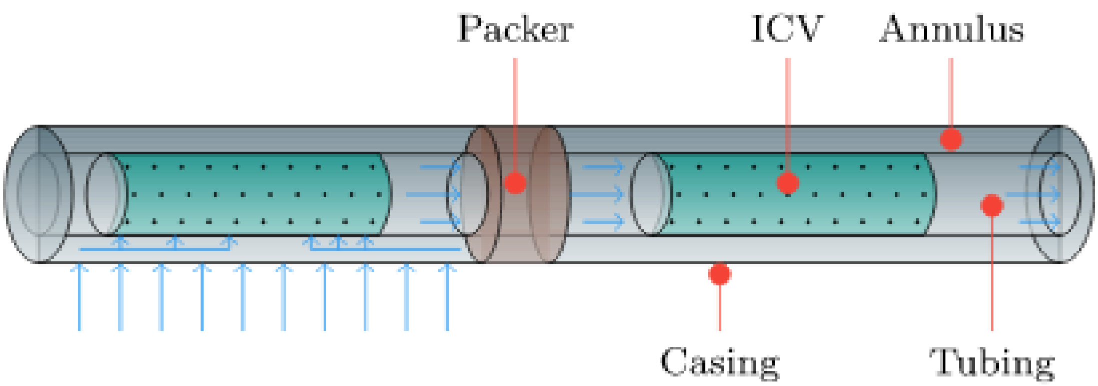


Figure 3.15: Illustration of well compartments separated by packers in the annulus with a single ICD in each compartment Baumann et al. (2020).

The well completion described above is modelled as a multi segment well in flow using the WELSEGS key word. The three main segments are the tubing segment, ICD segment and the annulus segment. The tubing segment is further split into compartments, each compartment is connected to an ICD. The ICD segment is then connected to the annulus. In this work each tubing compartment is modelled to contain a single ICD. The values specified in the WELSEGS key word to model the described well completion are tabulated in Table 3.7. The valve length and effective absolute roughness are small so the pressure drop across the valve due to friction is negligible.

Name	Value	Units
Length of tubing	-	m
Tubing roughness	1.5E-2	m
Tubing thickness	0.01	m
Valve length	0.01	m
Valve diameter fully open	0.1	m
Valve roughness	1.5E-15	m

Table 3.7: Values used under the WELSEGS keyword to describe the multi segment well completion.

3.5.2 Inflow Control Device Strength Calculation

A small valve length and roughness are specified in the WSEGVALV keyword such that the frictional pressure loss along the valve, $\Delta P_{friction}$ is negligible. With this assumption, ΔP consists only of the Pressure drop due to the constriction ($\Delta P_{constriction}$) such that equation Equation (3.10) for the ICD strength is reduced to Equation (3.11).

$$K = \frac{\Delta P}{\rho Q^2} \tag{3.11}$$

Using equations Equation (3.11) and Equation (3.8), the cross sectional area of the constriction A_r is calculated using Equation (3.12).

$$A_r = \sqrt{\frac{C_1}{2C_v^2}\frac{\rho Q^2}{\Delta P}} \tag{3.12}$$

In this work, the number of compartments modelled along the well is equal to the number of well segments with the highest NPV. Each compartment is modelled with a single ICD at the start of the compartment. The single ICD in each segment is modelled to reflect the optimal pressure distribution determined for the corresponding well segment. This is done by defining the size of the ICD constriction A_r calculated using equation Equation (3.12).

In order to calculate A_r using the optimal BHP results obtained from the workflow, the total pressure drop across each ICD, Δ P will be the difference between the average optimal BHP of the corresponding well segment and the lowest average optimal BHP. In this work the well is modelled with passive Inflow control devices (ICDs), whose settings as described in Section 2.2 are constant throughout the life of the field unless the well completion is replaced, thus the average optimal BHP over the production period are used. This is the average of the BHP at the different control time steps. For the ICD whose corresponding well segment's optimal BHP is the minimum average BHP, that ICD is modelled fully open with the value of A_r set to the maximum.

The dimensionless flow coefficient C_v of the ICD is the standard flow rate at which fluid flows through the ICD at a standard pressure drop across the ICD of 1psi at standard temperature. The value is supplied by the ICD manufacturer, in this work a value of 0.5 is assumed. The average liquid production rate, (Sm^3/day) over the simulation period of each well segment is used as the value of the volumetric flow rate Q for the corresponding ICD. The other values to be used in calculating and modelling of the ICD settings are tabulated in Table 3.8 below.

Property	**Value**	**Units**
Density of fluid mixture	958.915	kg/m^3
C_v	1	-
C_1	1.340 x 10^{-15}	-
Max. A_r	0.00785398	m^2

Table 3.8: Table of values used to calculate A_r

Chapter 4

Results

In this chapter the results of the study cases described in Section 3.2 are presented. For each case the trend of the Net present value (NPV) with number of control steps and number of optimization evaluations is plotted. For each of the well segment configurations, the change of the Bottom hole pressure (BHP) with time, and fluid rates are visualised in ResInsight. The plots for the different well partition configurations are presented in Appendix B. The ICD settings calculated from the final outcome of the workflow for each case are modelled and the resulting production profiles compared. Figure B.1 in Appendix B shows the different well segments modelled.

4.1 Case 1: Homogeneous Reservoir with Aquifer support

Using the results of the optimization with only a single control step, the trend of the NPV with number of well segments is plotted. From Figure B.1, it is seen that dividing the well into more than 8 segments creates unequally spaced segments thus the maximum number of segments the well is divided into is 8. Table 4.1 gives a summary of the final NPV obtained for each well segment configuration and the maximum number of control steps used to attain it.

No. of well segments	NPV (USD)	FOPT (Sm^3)	FWPT(Sm^3)	Max.Control steps
2	9.984E8	4.11E6	3.86E6	8
4	1.030E9	4.23E6	4.09E6	4
6	1.056E9	4.13E6	3.44E6	4
8	1.084E9	4.14E6	3.36E6	2

Table 4.1: Case 1:Summary of workflow results.

The computational cost of the workflow is visualized using plots of the NPV versus the number of evaluations used for each well segment configuration in Figure 4.3. For Case 1, the best NPV was achieved with the 8 well segment configuration ,the flux profile across the well segments is plotted in Figure 4.2 using the average of the Well liquid production rate (WLPR) of each

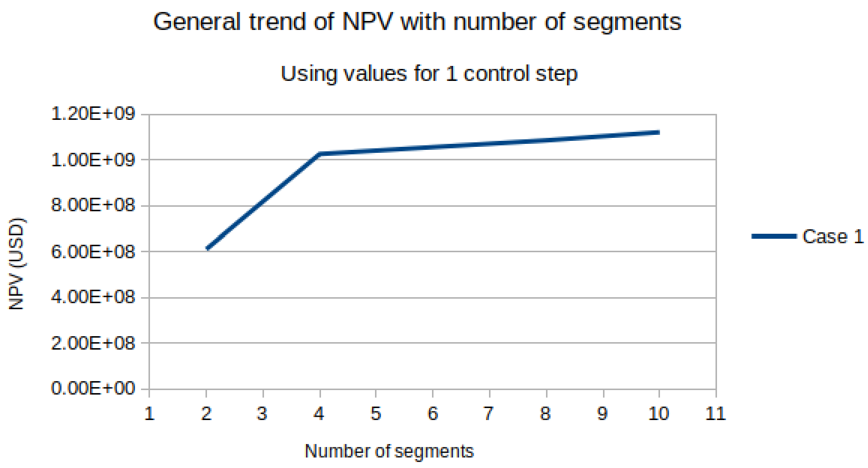


Figure 4.1: Trend of NPV with number of well segments

segment over the production period.

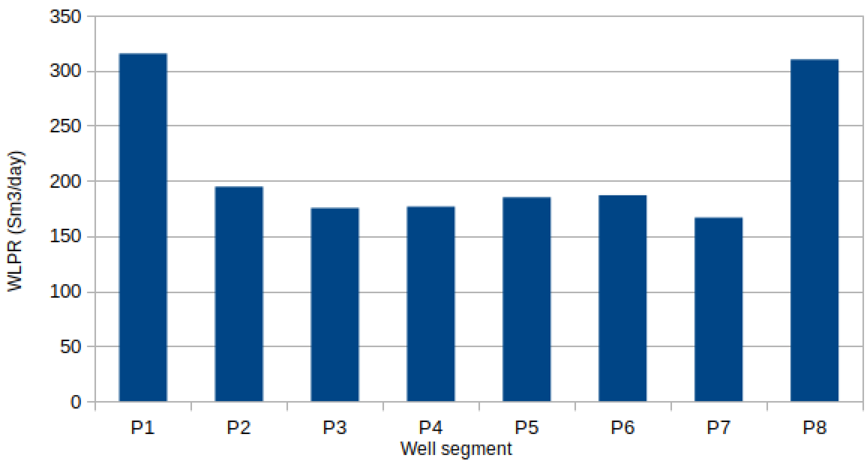


Figure 4.2: Average liquid rate of each well segment in the 8 well segment configuration

The horizontal well is remodelled with 8 ICDs corresponding to the 8 well segments. The values for the calculation of the cross sectional areas ,A_r of the ICDs as described in Section 3.5.2 are tabulated in Table 4.2. The resulting production profile of the reservoir with ICDs is presented in Figure 4.5. Well segment P1 has the lowest optimal BHP as seen in Table 4.2, and is thus modelled as fully open.

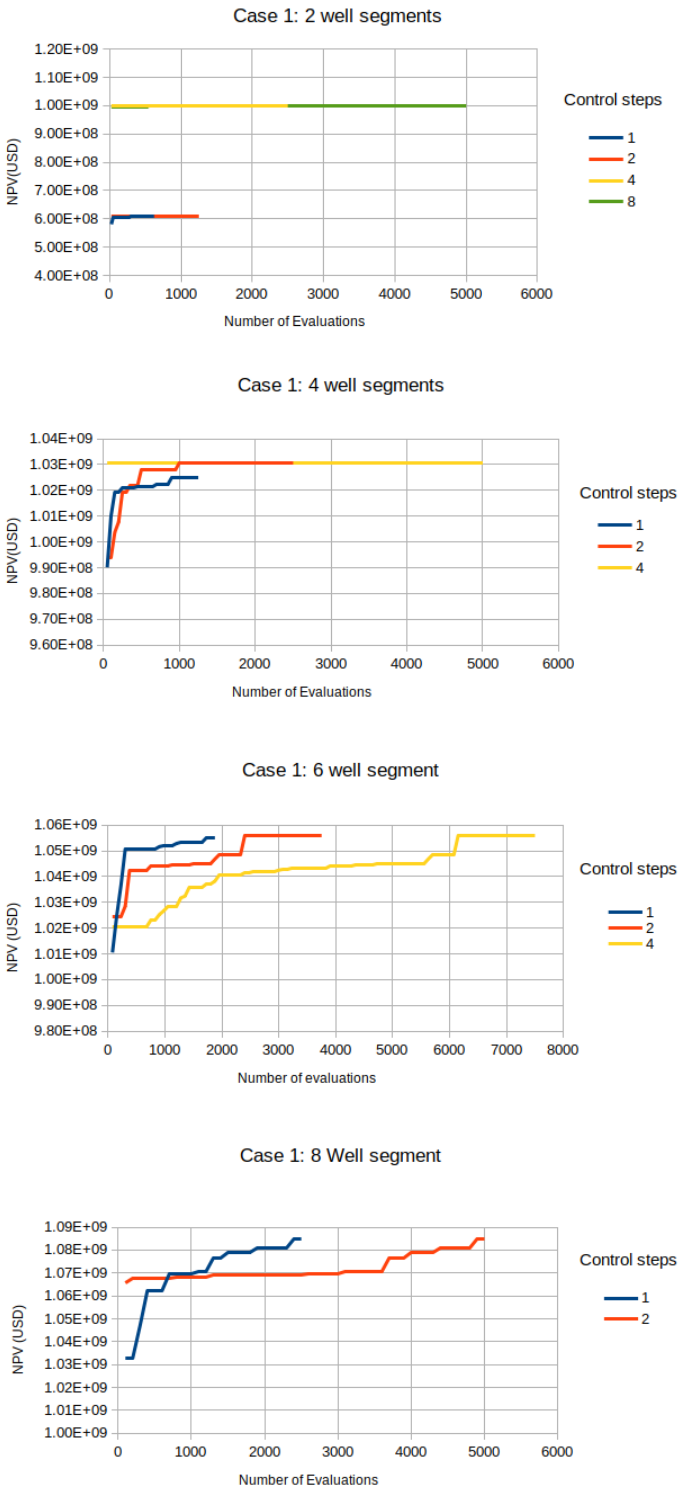


Figure 4.3: Case 1: Performance of the optimization step of the workflow for the different well segment configurations.

Well segment	Average BHP(bar)	$\Delta P(bar)$	Average WLPR (Sm^3/day)	A_r (m^2)
P1	**82.5996**	-	315.53	0.007853982
P2	119.1076	36.5081	194.48	2.57995E-5
P3	127.3658	44.7662	175.16	2.09839E-5
P4	127.7808	45.1812	176.41	2.10366E-5
P5	125.2987	42.6991	184.82	2.26712E-5
P6	124.2159	41.6163	184.82	2.29643E-5
P7	127.7541	45.1546	166.93	1.9916E-5
P8	85.6089	3.0094	310.16	0.000143311

Table 4.2: Case 1:Cross sectional area of the ICDs, A_r calculated from the optimal BHP obtained for each corresponding well segment.

The resulting oil and water production profile of the HW modelled with 8 ICDs is compared to that of 8 well segments in Figure 4.4. Figure 4.5 shows the impact of the ICDs on the HW production profile for case 1.

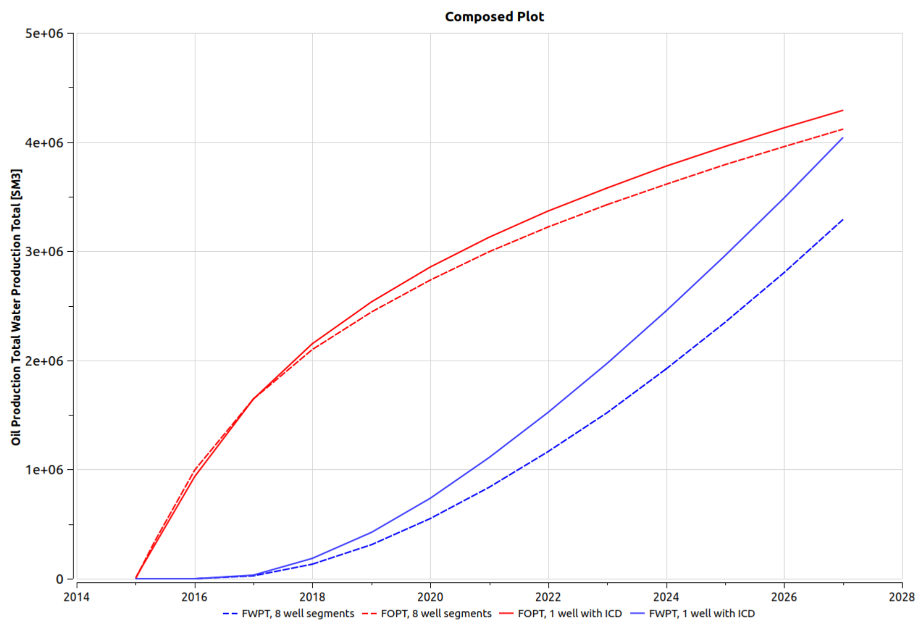


Figure 4.4: Comparing the Oil and water production profiles of the HW remodelled with 8 ICDs and the 8 well segment model

	FOPT (Sm^3)	FWPT(Sm^3)
With out ICD	4.982E6	8.653E6
With ICD	4.289E6	4.039E6

Table 4.3: Case 1:Comparing the final fluid productions for the model with and without ICDs

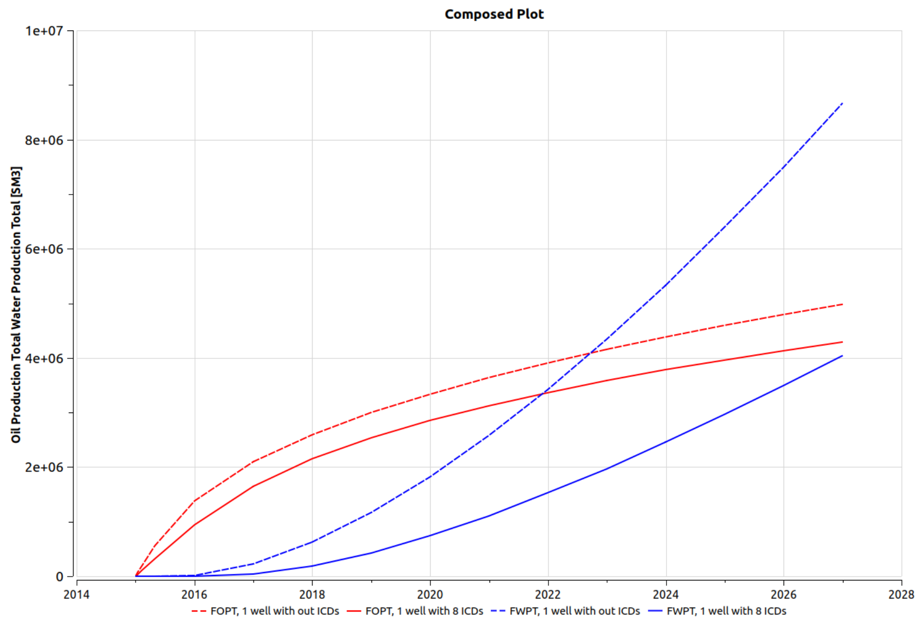


Figure 4.5: Case 1: Oil and water production profile for HW without and with ICDs installed

4.2 Case 2: Heterogeneous Reservoir with Aquifer support

Similarly using the NPV obtained with respect to 1 control step for each well segment configuration, Figure 4.6 shows the trend of the NPV with number of well segments for case 2.

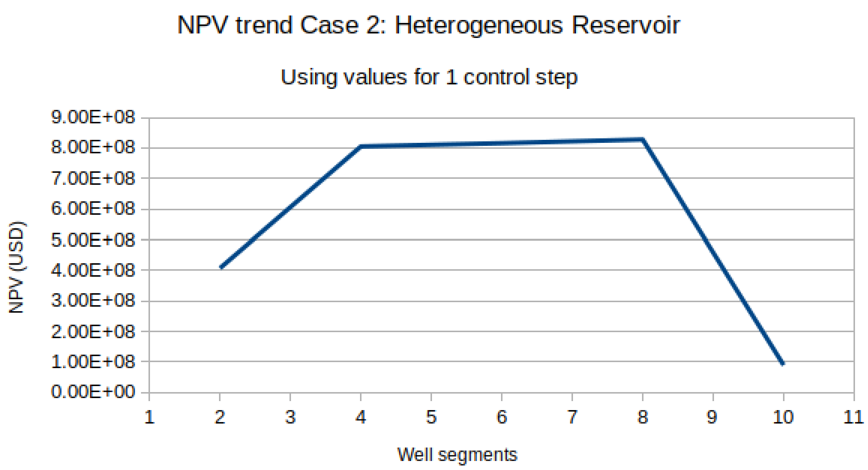


Figure 4.6: Trend of NPV with number of well segments

Table 4.4 is a summary of the NPV obtained for each number of well segments, the final total fluid productions and the number of well control steps used to achieve the maximum NPV.

No. of well segments	NPV (USD)	FOPT (Sm^3)	FWPT(Sm^3)	Max.Control steps
2	7.18E8	4.254E6	6.087E6	4
4	2.66E9	4.223E6	5.28E6	4
6	2.88E9	4.38E6	7.17E6	2
8	1.03E9	4.18E6	5.68E6	2

Table 4.4: Case 2:Summary of workflow results.

For case 2, Figure 4.7 shows the optimization runs that were completed within the available time frame. In this case, the number of well segments the well was divided into was capped at 8 as the 10 well segment had a lower NPV when optimized with a single control step as seen in Figure 4.6. This indicated that the subsequent optimization runs of the 10 well segments with more control steps would still yield a lower NPV compared to the 8 well segment. From Table 4.4 and Figure 4.7, the highest NPV is obtained with 6 well segments optimized with 2 well control steps.

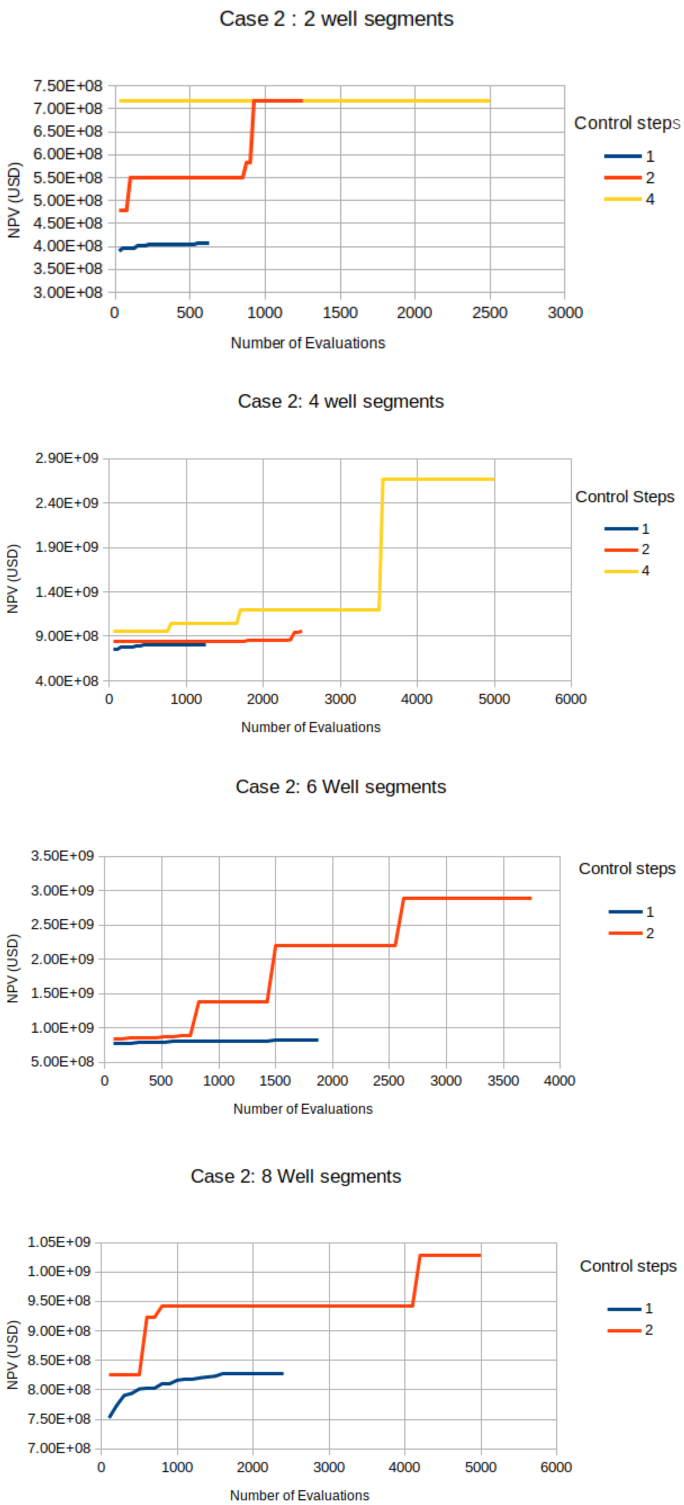


Figure 4.7: Case 2: Performance of the optimization step of the workflow for the different well segment configurations.

Figure 4.8 shows the liquid production profile along the well segments after optimization. The permeability variation along the well path is shown in Figure 4.9, we see that the well segments P3 and P4 in the high permeability region have the highest production rates. Using the method described in Chapter 3, the values of A_r in Table 4.5 are calculated and used to remodel the well with 6 ICDs.

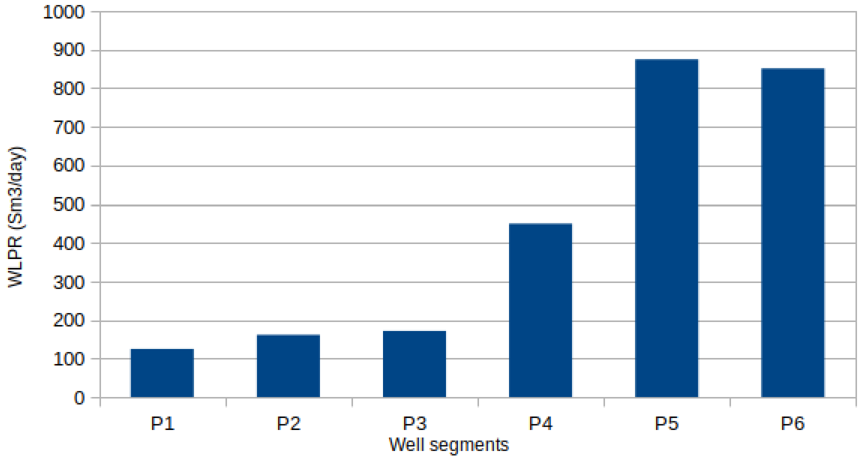


Figure 4.8: Liquid rate of each well segment in the 6 well segment configuration.

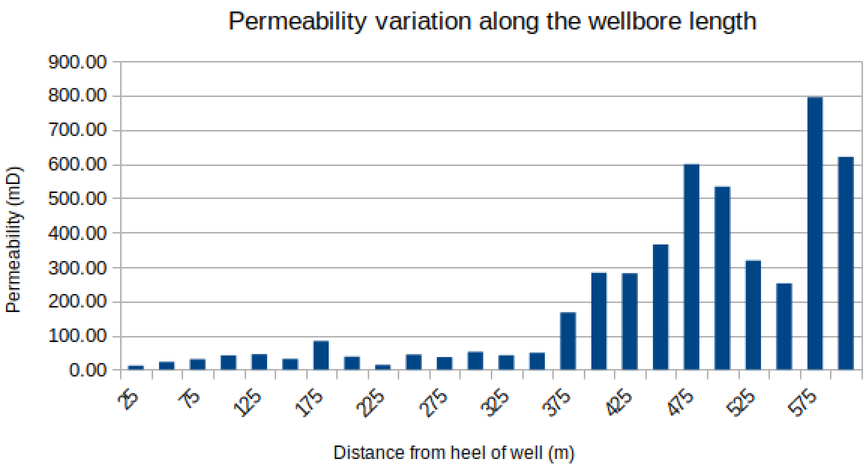


Figure 4.9: Variation of the permeability along the well path for Case 2.

Well segment	Average BHP(bar)	$\Delta P(bar)$	Average WLPR (Sm^3/day)	A_r (m^2)
P1	**97.272177**	-	124.96	0.007853982
P2	110.05893	12.78675	161.61	3.62261E-5
P3	104.23719	6.965011	171.66	5.21373E-5
P4	115.40532	18.13315	450.22	8.47451E-5
P5	110.94776	13.67559	875.14	0.000189684
P6	105.64665	8.374474	851.55	0.000235863

Table 4.5: Case 2:Cross sectional area of the ICDs,A_r calculated from the optimal BHP obtained for each corresponding well segment.

The production profile of the horizontal well modelled with 6 ICDs is compared to the production profile of the model produced with 6 well segments in Figure 4.10. A comparison of the horizontal well with and without ICDs is shown in Figure 4.11 with final oil and water production values listed in Table 4.6.

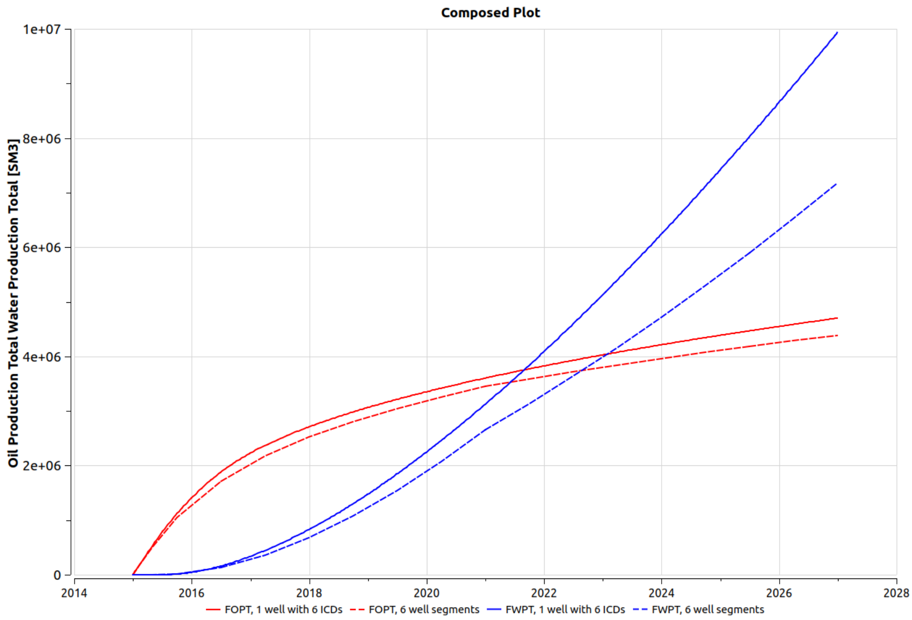


Figure 4.10: Production profiles for well modelled with 6 ICDs and 6 well segments model.

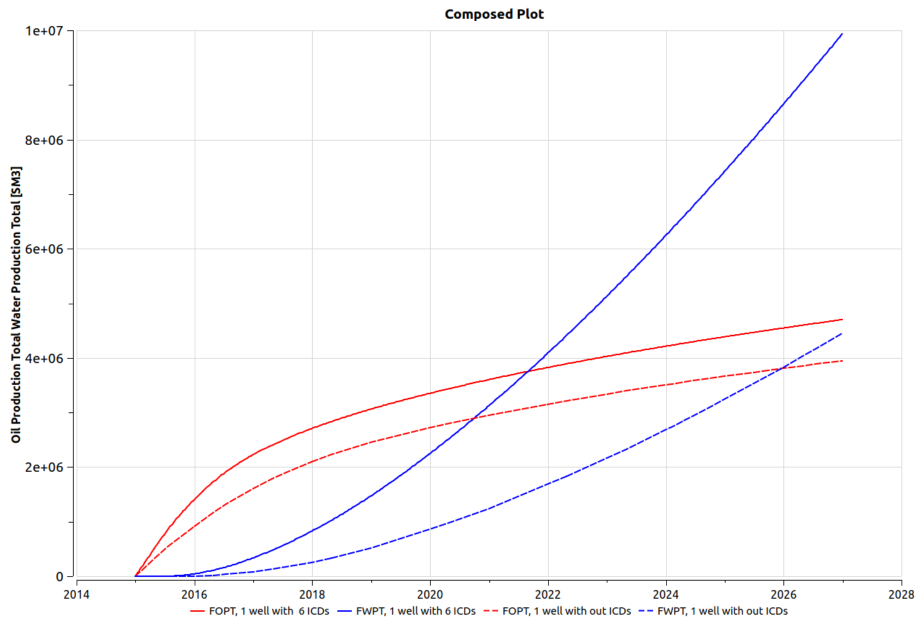


Figure 4.11: Case 2:Production profiles of HW with and without ICDs.

	FOPT (Sm^3)	FWPT(Sm^3)
With out ICD	3.95E6	4.45E6
With ICD	4.70E6	9.93E6

Table 4.6: Case 2: Comparison of total fluid production.

The data files of the resulting models with ICDs can be seen at `https://github.com/marinaki15/OptimalWellInflow` in the models with ICD folder.

Chapter 5

Discussion

In this chapter, the results of applying the workflow on the different study cases and the outcomes of modelling each case with the Inflow control device (ICD) completion are discussed. From the results of both cases, it is seen that as the number of well segments increases the control of fluid flow into the well is more localised such that the water breakthrough is delayed in case 1 and oil production is increased in case 2. The improved control of fluid inflow is seen to increase the NPV as seen in Figure 4.1 and Figure 4.6 where the NPV increases with increasing number of well segments. Additionally, the improved well inflow control along the well path is shown in the increase in resolution of well production rates plots shown in Appendix B as the number of well segments increase.

From the case of the homogeneous reservoir, the maximum number of well segments the well could be divided into with respect to the NPV was hard to determine as the NPV increased as seen in Figure 4.1 to up to 10 well segments. This was not practical when modelling, as dividing the well beyond 8 segments resulted into unequal spacing of the well segments as seen in Figure B.1. This would introduce another optimization variable of well segment placement which is not in the scope of this work.

The maximum number of segments the well was divided into was thus capped at 8 for this case. From this, the well cost becomes an input parameter for the workflow as the value has an impact on the maximum number of well segments with respect to the NPV. This is important as it represents the economic constraint on determining the appropriate number of ICDs that should be used. An alternative would be setting a minimum well segment length to determine the maximum number of well segments the Horizontal well (HW) can be divided into.

For case 2, the increase in NPV with number of well segments peaks at 8 well segments after which there is a sharp decline in NPV for 10 well segments. This decline of NPV is due to the heterogeneous nature of the reservoir which reduces oil recovery as compared to the homogeneous reservoir. The reduced revenue from oil production means that the well cost for 10 well segments will significantly impact the NPV unlike the case of the homogeneous reservoir. In addition to well costs, well placement plays a role in the final NPV for a heterogeneous reservoir but this out of the scope of this work as stated earlier.

For all the well segment configurations in both case 1 and case 2, the NPV increases with increase in the number of control time steps as seen in Figure 4.3 and Figure 4.7. There is a trade off between number of well segments and number of control steps. That is, as the number of well segments increase the number of well control steps required to maximize NPV reduce. The figures also show the increase in computational cost with increased number of well segments and control steps.

The results from the two study cases suggest that the final outcome of the ICD implementation depends on the factor dominantly causing the unbalanced flow along the wellbore length. In case 1, the pressure losses along the well led to water breakthrough in the middle sections of the HW. The workflow in this case reduces the pressure losses by using a high number of ICDs along the HW. In case 2, the reservoir permeability heterogeneities create zones of high production and would ideally require more ICDs in those zones. These zones are allowed to produce as much as possible in order to maximize oil production before water breakthrough occurs. In this case including the optimization variable of the placement of the ICD would be beneficial so as to have a higher number of ICDs in the high production zones that require more well control.

In this work, the cost of produced water used in the NPV calculation is set to 24 USD/bbl to increase the optimization algorithms' sensitivity to water production. This value is higher than that used in the industry. Using a lower value of 6 USD/bbl will not change the general trend of the optimal BHP settings but will give higher oil recoveries than seen in the results discussed in Chapter 4 as the well segments will be chocked to a lesser degree.

The PSO optimization algorithm described in Chapter 2 performs well within the workflow in terms of determining the maximum of the objective function. As the number of variables of the optimization problem increase within the workflow, it can be noted that the algorithm struggles to converge to the optimal point as more evaluations are required at each subsequent step of the workflow. This can be attributed to the fact that the algorithm searches the entire search space globally at each optimization run.

5.1 Case 1: Homogeneous Reservoir

The 8 well segment with 4 control time steps gives the maximum NPV. For the homogeneous reservoir, the fluid inflow profile into the 8 well segments is U-shaped as seen in Figure 4.2. This is similar to that discussed in Daneshy et al. (2012) where the heel and toe regions of the horizontal well have higher production rates as they have a larger reservoir contact area. Well segments in the middle section ; P2 to P7, are set to higher BHP therefore restricting and delaying water breakthrough in the middle section of the well.

Figure 4.4 compares the final fluid production profiles of the case modelled with 8 ICDs and the model with 8 well segments to gain an understanding of the translation of ICD settings from the workflow results. From the figure we see that the single HW with 8 ICDs has a higher FOPT than the 8 well segments as the single well has a longer effective wellbore length than the 8 well segments. The difference in the total productions is low as the pressure loss along the single well is countered by the ICDs while the pressure losses along the 8 well segments is negligible due to the short lengths of the well segments.

The production profiles of the horizontal well with and without ICDs are compared in Figure 4.5. For the HW without ICDs, water breakthrough occurs in 2024 while with ICDs water breakthrough does not occur at all and the FWPT is greatly reduced by over 50%. The delay of water breakthrough is at the expense of oil production with FOPT reduced to 4.2E6Sm^3 with ICDs from 4.8E6Sm^3 without ICDs.

5.2 Case 2: Heterogeneous Reservoir

In this case, the variation of the permeability along the well path as shown in Figure 4.9 determines the pressure distribution along the well. The 6 well segments with 2 control time steps gives the maximum NPV as seen in Figure 4.7. The fluid inflow profile shown in Figure 4.8 corresponds with the permeability variation along the well path. The permeability along the well path increases as you move towards the toe of the HW thus the WLPR increases from P1 to P6. Well segment P5 has a slightly higher WLPR than well segment P6 as the length from 400m t0 500m has a higher average permeability.

As with case 1, the production profile of the model with 6 well segments is compared to the model of the HW with 6 ICDs in Figure 4.10. The trend of the production profiles is similar with differences arising due to the effective lengths of the wells and effect of pressure drop along the wells. The single HW with 6 ICDs does perform better as expected due to longer effective well length and less pressure loss effects along the well bore.

A final comparison is made between the models with and without ICDs in Figure 4.11. In this case, the ICD completion led to a 18.98% increase in the final total oil production. The final total water production doubled during the production period and is accompanied by an early water breakthrough in 2021 as compared to 2026 when the reservoir is produced with out ICDs. Here the outcome of maximizing the NPV to determine the optimal pressure distribution is that the oil recovery before water breakthrough occurs is maximised.

Chapter 6

Conclusion

The aim of the work was to develop a working process with which ICDs are designed based on the optimal pressure distribution along the well path in a reservoir. The optimal pressure distribution is that which maximizes the Net present value. The following conclusions are made about the workflow proposed to determine the optimal pressure distribution along the well path:

- The positive results from the cases described in Chapter 3 show that an optimal pressure distribution along a well path with respect to the NPV can be obtained by optimizing the well controls of the individual well segments the well is divided into as described in Section 3.1.
- Modelling individual well segments along the well path is a viable approach of determining the optimal pressure distribution along the well path as seen in the increased resolution in well production rates allowing localised well inflow control.
- The optimization section of the workflow that determines the optimal pressure distribution along the well paths has a high computational cost as seen in Figure 4.3 and Figure 4.7.
- The PSO optimization algorithm used within the workflow, requires increasing number of evaluations to reach convergence as the number of well segments increase.
- As the NPV increases with the number of well control time steps being optimized, the workflow successfully determines the optimal number of well control time steps required for each well segment partition configuration.
- The final result from the workflow depends on the optimization algorithm used, cost of water produced and the fixed well cost impact. These should thus be treated as tuning parameters of the workflow.
- The NPV is a good criteria to use to determine the optimal pressure distribution along the well path.

Chapter 3 described the method used to translate the optimal pressure distribution along the well path obtained from the workflow to ICD settings. The following conclusions are made:

- The method used is a first order approximation that performs well for the simple study cases used in this work as seen in Figure 4.10 and Figure 4.4 in which the difference between the resulting production profiles of the reservoir with optimized well segments

and the HW with the corresponding ICDs are similar.
- The use of average WLPR, density and BHP to model the valve ICD is a good approximation assuming that each valve sees a uniform fluid mixture.

The study cases had positive results when the workflow was applied on them. In case 1 the amount, of water produced is reduced when the well is produced with the ICDs. The reduction in water production despite the lowered oil recovery is positive in terms of reduced water handling costs and energy consumption required to separate and handle the produced water. Additionally, the carbon footprint of the water separation and treatment process is reduced. In case 2 the final outcome is of improved oil recovery. In this case the cumulative oil produced was maximized before water breakthrough occurred.

Further work

Due to time and computational constraints a number of tasks were not included in this work. These have formed the basis of the recommendations made for further work that can be done to further improve the proposed workflow.

Parameter tuning

As noted in the conclusion, the PSO method does perform well within the workflow but requires more evaluations as the number of variables increase. A bench marking study can asses the performance of different optimization algorithms with the workflow. In addition to this, a sensitivity analysis of the different workflow tuning parameters identified to study how the optimal pressure distribution behaves.

Automation

The method described for translating the optimum BHP values to ICD settings is not included in Code listing A.4. Automation of this method will ease the sensitivity analysis of the workflow tuning of the parameters.

Autonomous inflow control Device

In this work only a passive ICD has been modelled based off the workflow results. Further work can be done to develop a method to translate these results to model Autonomous inflow control devices. This means that the modelled AICDs will be able to adapt to the changing reservoir properties. With this view, inclusion of history matching in the workflow would be an interesting aspect.

Inflow control device modelling

As earlier stated, in this work the ICDs are modelled as a single ICD in a well compartment corresponding to the well segment. The ICD strength is modelled to replicate the optimal BHP of that well segment. Further work can be done to refine the translation of the optimal pressure distribution along the well and optimize the placement of the ICDs along the HW.

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Appendix A

Python Code Listings

Appendix A contains the different code used to complete the different tasks. It also includes the Python code written for the automation of the proposed workflow.

Code listing A.1: Calculating NPV to obtain objective function surface.

```
#!/usr/bin/env python3
# -*- coding: utf-8 -*-
"""
Created on Sat Oct 31 13:23:05 2020

@author: m
"""


import numpy as np
import os
from ecl.summary import EclSum
import sys


#Function for calculating cashflows
def CF(fPo,fPw,wellcost,fopt,fwpt):
    Cf=np.zeros(len(fopt)+1)
    Cf[0] = wellcost
    Cf[1:] = ((np.asarray(fopt)*fPo*6.2898)+(np.asarray(fwpt)*fPw*6.2898))
    #Cf.append([Cf[0],Cf[1:]])
    return Cf

#BHP Variable ranges
seg1 = np.arange(80,151,2)
seg2 = np.arange(80,151,2)

#$/barrel
fPo=60
fPw=-24
wellcost=-16025000

NPV=[]
FOPT=[]
FWPT=[]

for ii in range(0,np.size(seg1)):
```

```
for jj in range(0,np.size(seg2)):
    input_file='2WSHOEBOX.DATA'
    file1 = open(input_file,"r")
    data = file1.readlines()
    output_file='2WCASE' + '.DATA'
    file2 = open(output_file,"w")

    #rewriting BHPs
    line1 = data[368]
    line1_pre = line1[:30]
    line1_whole = line1_pre + str(seg1[ii]) + "␣/␣\n␣"

    line2 = data[369]
    line2_pre = line2[:30]
    line2_whole = line2_pre + str(seg2[jj]) + "␣/␣\n␣"


    data[368] = line1_whole
    data[369] = line2_whole

    file2.writelines(data)
    file1.close()
    file2.close()

    #Simulating generated data file and extracting FOPT and FWPT data
    os.system('flow' +'␣'+'2WCASE' + '.DATA' )

    summary = EclSum('2WCASE')
    fopt = summary.numpy_vector("FOPT",report_only="True")
    fwpt = summary.numpy_vector("FWPT",report_only="True")

    FOPT.append(fopt)
    FWPT.append(fwpt)

    #calculating the cashflow
    cashflows = CF(fPo,fPw,wellcost,fopt,fwpt)

    #calculating the NPV
    npv = 0
    for xx in range(13):
        DCash=cashflows[xx]/((1+0.08)**(xx+1))
        npv=npv+DCash

    NPV.append([seg1[ii],seg2[jj],npv])

    #saving data to txt files
np.savetxt('FOPT2.txt', FOPT, fmt="%s\n", delimiter= '␣', newline= "\n", header= "FOPT")
np.savetxt('FWPT2.txt', FWPT, fmt="%s\n", delimiter= '␣', newline= "\n", header= "FWPT")
np.savetxt('NPV2.txt', NPV, fmt="%1.1f", delimiter= '␣', newline= "\n", header= "BHP1␣␣BHP2␣␣NPV")
```

Code listing A.2: Plotting objective function surface.

```
import numpy as np
from mpl_toolkits.mplot3d import Axes3D
import matplotlib.pyplot as plt
from matplotlib import cm


BHP2 = np.loadtxt("BHP2.csv", delimiter=",")
BHP1 = np.loadtxt("BHP1.csv", delimiter=",")
NPV = np.loadtxt("NPV.csv", delimiter=",")

X = BHP1
xlabel = "Segment␣1␣BHP␣[bara]"
Y = BHP2
ylabel = "Segment␣2␣BHP␣[bara]"
X, Y = np.meshgrid(X, Y)

Z = NPV
zlim_min = 0
zlim_max = Z.max()
zlabel = "optimal␣NPV␣[USD]"

title = "surface:␣optimal␣NPV"

fig = plt.figure(figsize=(7.5, 6))
ax = fig.add_subplot(111, projection='3d')
surf = ax.plot_surface(X, Y, Z, cmap=cm.jet, linewidth=0,
     antialiased=False, vmin=zlim_min, vmax=zlim_max)
ax.set_zlim(zlim_min, zlim_max)
ax.set_xlabel(xlabel)
ax.set_ylabel(ylabel)
ax.xaxis.set_tick_params(labelsize=8)
ax.yaxis.set_tick_params(labelsize=8)
ax.zaxis.set_tick_params(labelsize=8)
cbar = fig.colorbar(surf, ax=ax, shrink=0.5, aspect=5)
cbar.set_label(zlabel)
ax.set_title(title, loc="left")
ax.view_init(75, -120)
plt.tight_layout()
plt.show()
```

Code listing A.3: Extracting Porosity and Permeability values.

```
#!/usr/bin/env python3
# -*- coding: utf-8 -*-
"""
Created on Mon Oct 12 12:04:26 2020

@author: m
"""

import numpy as np
data = np.loadtxt("./SPE10MODEL2_PERM.INC")
print("current␣shape␣of␣data:",data.shape)
PermZ = data[374010:386010,:]
#PermX = PermX.reshape(72000,1)
print("modified␣shape␣of␣data:",data.shape)
print(PermZ)

#np.savetxt("permz_SHOEBOX.INC",PermZ, fmt= "%s")
a_file = open("permz_SHOEBOX.INC","w")
for row in PermZ:
    np.savetxt(a_file,row, fmt = "%s")

a_file.close()

fname = "permz_SHOEBOX.INC"
file = open(fname,"r")
data = file.readlines()
file.close()
file = open(fname,"w")
file.write("PermZ␣\n")
file.writelines(data)
file.write("/")
file.close()
```

Code listing A.4: Proposed workflow automation.

```
import json
import numpy as np
import pandas as pd
import sys
import os.path
from os import path
import os
import shutil
from inputs import *


#Partitioning wells function
def split(start, end,segments,spacing):
#spacing usually model cell size to avoid wells penetrating the same cell
    for jj in range(0,np.size(start)):
        #size of input coordinates
        x_delta = (end[jj] - start[jj]+2*spacing) / float(segments)
        #z_delta = (end[jj+2] - start[jj+2]) / float(segments) #for deviated wells
        z_delta = 0 # for horizontal wells
        points = []
        for i in range(0, segments):
            points.append([start[jj]-spacing+i*x_delta+spacing,start[jj+1],
                start[jj+2]+i*z_delta,
            start[jj]-spacing + (i+1) * x_delta-spacing,start[jj+1],start[jj+2]
            + (i+1) * z_delta])
        return points
#Generating control time steps for json file
def Controlsteps (years,steps):
        Timesteps =[]
        T_delta = (years*365)/steps
        for i in range(0,steps):
                T = round(i*T_delta)
                Timesteps.append(T)
        return Timesteps

def Timesteps (years,steps):
        Timesteps =[]
        T_delta = (years*365)/steps
        for i in range(0,(steps+1)):
                T = round(i*T_delta)
                Timesteps.append(T)
        return Timesteps

##################################Start of workflow############################

#Splitting well and generating new well partiton coordinates
coordinates=split(heel,toe, ii,spacing)
np.savetxt('coordinates.csv',coordinates,fmt="%1.1f",delimiter=',',newline="\n",
header = "x,y,z,x,y,z")

#loading well segment coordinate file
df=pd.read_csv("coordinates.csv")

#loading initial driver file
jsonfile = DRIVER_FILE + CASE +'.json'
with open(jsonfile, 'r') as file1:
        data = json.load(file1)
```

```
#adding well control tab
#editing well P1 coordinates
P1_heel = {'IsVariable':False,'x':df.iloc[0,0],'y':df.iloc[0,1],'z':df.iloc[0,2]}
P1_toe = {'IsVariable':False,'x':df.iloc[0,3],'y':df.iloc[0,4],'z':df.iloc[0,5]}
data['Model']['Wells'][0]['SplinePointArray']=[]
data['Model']['Wells'][0]['SplinePointArray'].append(P1_heel)
data['Model']['Wells'][0]['SplinePointArray'].append(P1_toe)


for jj in range(1,ii):
        control = {'Controls':[{'BHP': 110, 'IsVariable':True, 'Mode':'BHP', 'TimeStep':0}],
        'DefinitionType':'WellSpline','Group':'P','Name':'P'+str(jj+1),'PreferredPhase':'Oil',
        'SplinePointArray':
        [{'IsVariable':False,'x':df.iloc[jj,0],'y':df.iloc[jj,1],'z':df.iloc[jj,2]},
        {'IsVariable':False,'x':df.iloc[jj,3],'y':df.iloc[jj,4],'z':df.iloc[jj,5]}],
        'Type':'Producer','WellboreRadius': 0.125}

        data['Model']['Wells'].insert(jj,control)

        #Adding well in Optimizer tab
        data['Optimizer']['Constraints'][0]['Wells'].insert(jj,'P'+str(jj+1))


#Edits
data['Global']['Name']=str(ii)+'WSHOEBOXMODEL'
data['Simulator']['ScheduleFile']='include/'+str(ii)+'WSHOEBOXMODEL_SCH.INC'
data['Optimizer']['Parameters']['MaxGenerations'] = 1
#single evaluation needed to generete wellcompletion data

jsonfile_new = DRIVER_FILE+CASE+str(ii)+'.json'
with open(jsonfile_new, 'w') as file2:
        json.dump(data,file2,indent="   ")

############################################################################################
#creating model directory
if os.path.exists(NEW_MODEL) and os.path.isdir(NEW_MODEL):
        shutil.rmtree(NEW_MODEL)
        os.mkdir(NEW_MODEL)
else:
        os.mkdir(NEW_MODEL)

#Generating DATA File for FLOW simulation
with open(INITIAL_MODEL+'/1WSHOEBOX.DATA','r') as modelfile1:
        modeldata = modelfile1.read()

#editing data file
modeldata = modeldata.replace('./include/1WSHOEBOXMODEL_SCH.INC','./include/'
+str(ii)+'WSHOEBOXMODEL_SCH.INC')


#copying EGRID and INIT file
egrid1=INITIAL_MODEL+'/1WSHOEBOX.EGRID'
egrid2 = NEW_MODEL
shutil.copy(egrid1,egrid2)

init1 = INITIAL_MODEL+'/1WSHOEBOX.INIT'
shutil.copy(init1,NEW_MODEL)

#changing into new model working directory
```

```
os.chdir(NEW_MODEL)

#renaming copied egrid and init file
os.rename('1WSHOEBOX.EGRID',str(ii)+'WSHOEBOX.EGRID')
os.rename('1WSHOEBOX.INIT',str(ii)+'WSHOEBOX.INIT')

#Writing New DATA file
with open(str(ii)+'WSHOEBOX.DATA','w') as modelfile2:
        modelfile2.write(modeldata)

#creating and copying include files into model folder
#os.mkdir('include')

src = INITIAL_MODEL+'/include'
dst = NEW_MODEL+'/include'
shutil.copytree(src,dst)

os.chdir(NEW_MODEL+'/include')
os.rename('1WSHOEBOXMODEL_SCH.INC', str(ii)+'WSHOEBOXMODEL_SCH.INC')

###################################################################################

os.chdir(PROJECT_PATH)

#Running single evaluation to obtain COMPDATA
if os.path.exists(INITIAL_OUTPUT) and os.path.isdir(INITIAL_OUTPUT):
        shutil.rmtree(INITIAL_OUTPUT)
        os.mkdir(INITIAL_OUTPUT)
else:
        os.mkdir(INITIAL_OUTPUT)

os.system('FieldOpt'+'␣'+jsonfile_new +'␣'+ INITIAL_OUTPUT+'␣'+'-v'+'␣'+'3'+'␣'+
        '-f'+'␣'+'-r'+'␣'+'serial'+
        '␣' +'-g'+NEW_MODEL+'/'+str(ii)+'WSHOEBOX.EGRID'+'␣'+'-e'+'␣'+'bash_flw-bin.sh'+
        '␣'+'-s'+'␣'+NEW_MODEL+'/'
+str(ii)+'WSHOEBOX.DATA')

#extracting model file
shutil.rmtree(NEW_MODEL)
src = INITIAL_OUTPUT+'/model'+str(ii)
dst = FINAL_MODEL
shutil.move(src,dst)

#################################OPTIMIZATION LOOP ####################################
#optimization  Parameter tuning
jsonfile_old = CASE + str(ii)+ '.json'

with open(DRIVER_FILE + jsonfile_old, 'r') as file:
    data = json.load(file)
data['Optimizer']['Parameters']['MaxGenerations'] = 100 #setting maximum evaluations
data['Optimizer']['Parameters']['PSO-SwarmSize'] = (25*(ii/2))


with open(DRIVER_FILE + jsonfile_old, 'w') as file:
    json.dump(data,file,indent=4)


minT_delta = (t*365)/max_ctrlstep
currentctrlstep = 1
T_delta = (t*365)/currentctrlstep
```

```
if os.path.exists(OPT_OUTPUT+'_'+str(currentctrlstep)) and os.path.isdir(OPT_OUTPUT+
        '_'+str(currentctrlstep)):
        shutil.rmtree(OPT_OUTPUT+'_'+str(currentctrlstep))
        os.mkdir(OPT_OUTPUT+'_'+str(currentctrlstep))
else:
        os.mkdir(OPT_OUTPUT+'_'+str(currentctrlstep))


#initializing single control time step optimization
os.system('mpirun'+'␣'+ '-n'+ '␣'+ '8'+ '␣'+ FIELDOPT_BIN_PATH +'␣'+DRIVER_FILE +
        jsonfile_old +'␣'+ OPT_OUTPUT+'_'+str(currentctrlstep) +'␣'+'-v'+'␣'+'1'+'␣'+'-f'
        +'␣'+'-r'+'␣'+'mpisync'+'␣' +'-g'+FINAL_MODEL+'/'+str(ii)+'WSHOEBOX.EGRID'+'␣'+'-e'
        +'␣'+'bash_flow.sh'+'␣'+'-s'+'␣'+FINAL_MODEL+'/'+str(ii)+'WSHOEBOX.DATA')

#os.system('FieldOpt' +' '+CASE+'.json' +' '+ OPT_OUTPUT+'_'+str(currentctrlstep) +' '
        #+'-v'+' '+'3'+' '+'-f'+' '+'-r'+' '+'serial'+' ' +'-g'+NEW_MODEL+'/'+str(i)
        #+'WSHOEBOX.EGRID'+' '+'-e'+' '+'bash_flw-bin.sh'+' '+'-s'+' '+NEW_MODEL+'/'+str(i)+'WSHOEBOX.DATA')



#### loading optimization data for 1control step ################
#path opt_log depends on serial or parallel run is used
opt_log = OPT_OUTPUT+'_'+str(currentctrlstep)+'/rank0/log_extended.json'
with open(opt_log, 'r') as logfile1:
        optdata = json.load(logfile1)

BHP_data = optdata['Cases'][-1]['Variables']

with open ('bhp'+str(ii)+'.csv','w') as file:
        writer =csv.writer(file,delimiter=',')
        writer.writerow(["Key","Value"])
        for BHP in BHP_data:
                writer.writerows(BHP.items())

df=pd.read_csv('bhp'+str(ii)+'.csv',index_col='Key')

controlsteps_previous = Controlsteps(12,1)

npv_df=pd.read_csv(OPT_OUTPUT+'_'+str(currentctrlstep)+'/rank0/log_optimization.csv',sep=',')
npv1 = npv_df.iloc[-1,10]
NPV.append(npv1)
#################################################################

with open(DRIVER_FILE + jsonfile_old, 'r') as file1:
        data = json.load(file1)

data['Model']['ControlTimes'] = []

ControlTimes = Timesteps(t,16)
print(ControlTimes)

data['Model']['ControlTimes']= ControlTimes


while currentctrlstep <= max_ctrlstep:

        currentctrlstep = currentctrlstep*2
        controlsteps_current = Controlsteps(12,currentctrlstep)
```

```
        T_delta = controlsteps_current[1]
        print(controlsteps_current)

    #this is to be changed according to the optimization method used
        data['Optimizer']['Parameters']['MaxGenerations'] = (25*currentctrlstep)

        for jj in range(0,ii):

                data['Model']['Wells'][jj]['Controls'] = []


                for t in controlsteps_current:
                                #extract BHP at that time step
                                if t in controlsteps_previous:
                                        bhp = df.loc['Var#BHP#P'+str(jj+1)+'#'+str(int(t)),'Value']
                                        ctrlstep = {'BHP':bhp, 'IsVariable':True, 'Mode':'BHP', 'TimeStep':t}
                                        data['Model']['Wells'][jj]['Controls'].append(ctrlstep)

                                else :
                                        bhp = df.loc['Var#BHP#P'+str(jj+1)+'#'+str(int(t-T_delta)),'Value']
                                        ctrlstep = {'BHP':bhp, 'IsVariable':True, 'Mode':'BHP', 'TimeStep':t}
                                        data['Model']['Wells'][jj]['Controls'].append(ctrlstep)


        jsonfile_new = CASE +str(ii)+str(currentctrlstep)+'.json'
        with open(DRIVER_FILE + jsonfile_new, 'w') as file2:
                json.dump(data,file2,indent=4)


        if os.path.exists(OPT_OUTPUT+'_'+str(currentctrlstep)) and os.path.isdir(OPT_OUTPUT+'_'
                +str(currentctrlstep)):
                shutil.rmtree(OPT_OUTPUT+'_'+str(currentctrlstep))
                os.mkdir(OPT_OUTPUT+'_'+str(currentctrlstep))
        else:
                os.mkdir(OPT_OUTPUT+'_'+str(currentctrlstep))

        os.system('mpirun'+'␣'+ '-n'+ '␣'+ '6'+ '␣'+FIELDOPT_BIN_PATH+'␣'+DRIVER_FILE + jsonfile_new +
                '␣'+ OPT_OUTPUT+'_'+str(currentctrlstep)+'␣'+'-t'+'␣'+'300'+'␣'+'-v'+'␣'+'1'+'␣'+'-f'+'␣'+
                '-r'+'␣'+'mpisync'+'␣' +'-g'+'␣'+FINAL_MODEL+'/'+str(ii)+'WSHOEBOX.EGRID'+'␣'+'-e'+'␣'+
                'bash_flow.sh'+'␣'+'-s'+'␣'+FINAL_MODEL+'/'+str(ii)+'WSHOEBOX.DATA')

        #os.system('FieldOpt'+' '+DRIVER_FILE + jsonfile_new +' '+ OPT_OUTPUT+'_'+str(currentctrlstep)+
        #' '+'-v'+' '+'3'+' '+'-f'+' '+'-r'+' '+'serial'+' ' +'-g'+' '+FINAL_MODEL+'/'+str(ii)+
        #'WSHOEBOX.EGRID'+' '+'-e'+' '+'bash_flw-bin.sh'+' '+'-s'+' '+FINAL_MODEL+'/'+str(ii)+'WSHOEBOX.DATA')

        npv_df=pd.read_csv(OPT_OUTPUT+'_'+str(currentctrlstep)+'/rank0/log_optimization.csv',sep=',')
        npv2= npv_df.iloc[-1,10]

        NPV.append(npv2)
        if npv2==npv1: break

        controlsteps_previous = controlsteps_current

        opt_log = OPT_OUTPUT+'_'+str(currentctrlstep)+'/rank0/log_extended.json'
        with open(opt_log, 'r') as logfile1:
                optdata = json.load(logfile1)

        BHP_data = optdata['Cases'][-1]['Variables']

        with open ('bhp'+str(ii)+'.csv','w') as file:
```

```
                writer =csv.writer(file,delimiter=',')
                writer.writerow(["Key","Value"])
                for BHP in BHP_data:
                        writer.writerows(BHP.items())

        df=pd.read_csv('bhp'+str(ii)+'.csv',index_col='Key')
    npv1=npv2
np.savetxt('npv'+str(ii)+'.csv', NPV, fmt="%1.1f", delimiter= ',', newline= "\n",)
```

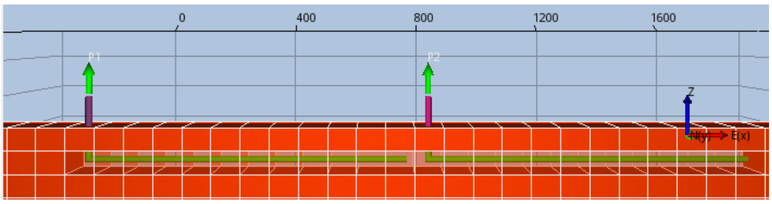
Code listing A.5: Input file used together with the automation code.

```
#INPUT VARIABLES

#Input variables for well partitioning and modelling loop
#Number of well  segments
ii =8

#Well partitioning inputs; heel and toe well coordinates, spacing
heel= [425,730,2005]
toe = [1025,730,2005]
spacing = 12.5


#Declare case(optimization algorithm)
CASE = 'fo_driver.CntrlOpt_inj.PSO'


#FieldOpt path
#FIELDOPT_BIN_PATH='/home/marinaki/git/PCG/FieldOpt/FieldOpt/cmake-build-debug/bin/FieldOpt'

#Directory Paths
PROJECT_PATH='/home/m/lib/Thesis/auto' #path to main project folder
#PROJECT_PATH='/home/marinaki/auto'
INITIAL_MODEL=PROJECT_PATH +'/1W_homogeneous' #path to initial single well model
NEW_MODEL=PROJECT_PATH + '/model'+str(ii) #path to new partitioned well model
DRIVER_FILE = PROJECT_PATH+'/Driverfiles/' #path to json driver files initial and generated
INITIAL_OUTPUT = PROJECT_PATH + '/initial' #temporary output location for single optimization run
OPT_OUTPUT = PROJECT_PATH + '/output/'+CASE +str(ii) #final optimization output
FINAL_MODEL = PROJECT_PATH+ '/models/Injector' #path all generated models for optimization

#Gridblock indices for well specs file [I,J]
heel2 = [18,30]
toe2 = [41,30]

#Specifyting Well control
wcon = 'BHP'
value = 130

#Input variables for optimization loop

#Simulation period in years
T = 12.0  #If using python 2.7 and below enter as an integer

#Maximum number of times BHP will be varied per well
max_ctrlstep = 16
```

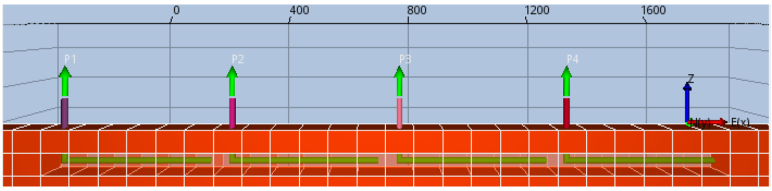
Appendix B

Additional Results

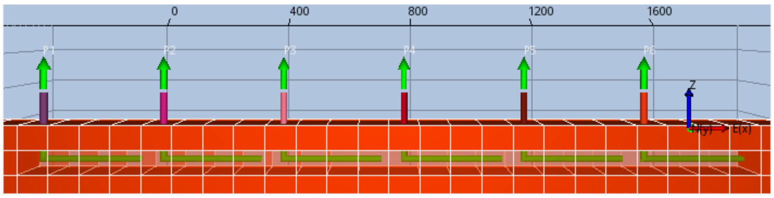
Additional results from the study cases are presented in Appendix B. The results include trend of the BHP with time, oil and water well production rates during the production period and the final fluid production total for all the well partition configurations.



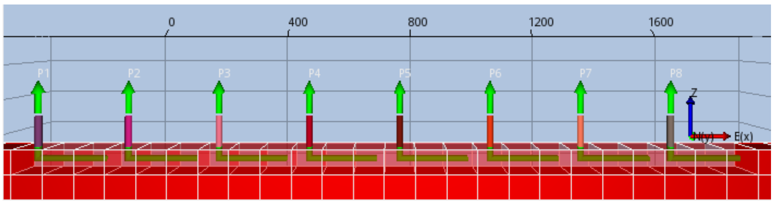
(a) 2 well segments



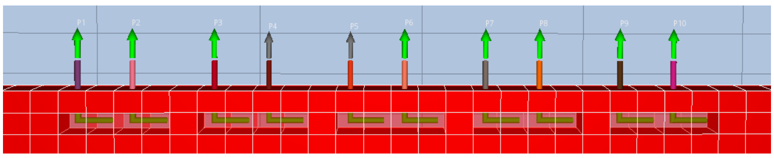
(b) 4 well segments



(c) 6 well segments



(d) 8 well segments

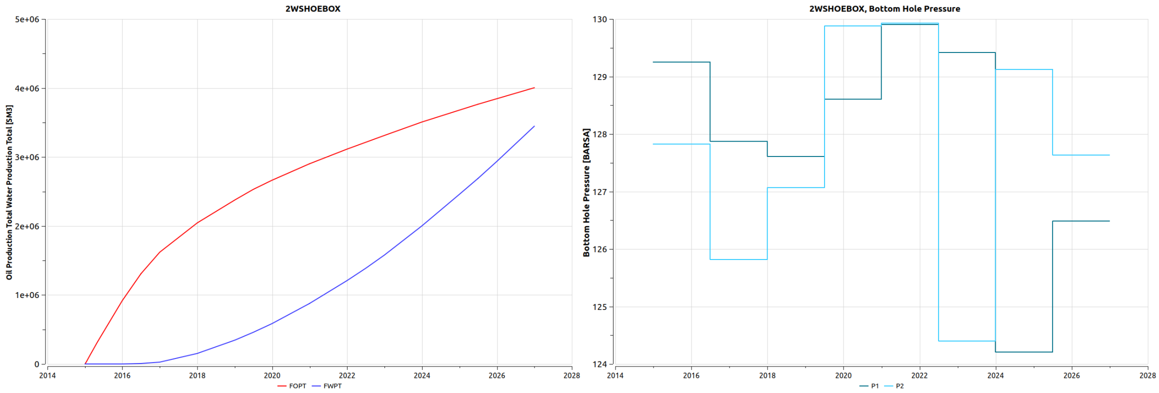


(e) 10 well segments

Figure B.1: Different well partition configurations used in the cases.

CASE 1: Homogeneous Reservoir with Aquifer support

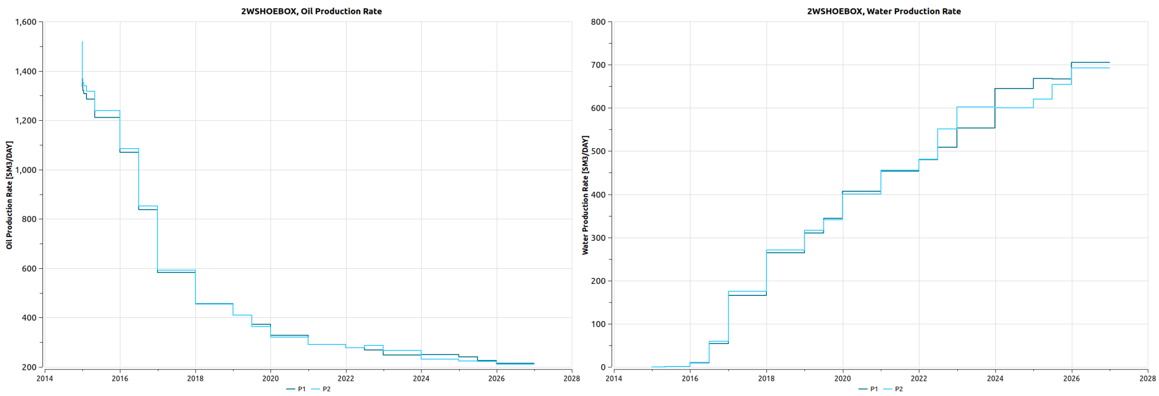
2 well segments



(a) Total oil and water production profile for 2 well segment configuration

(b) Variation of the BHP with time

Figure B.2: Final water and oil production profiles for 2 well segments and corresponding optimal BHP

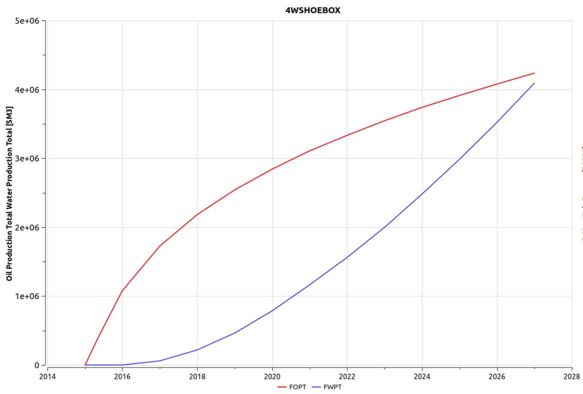


(a) Well oil production rates

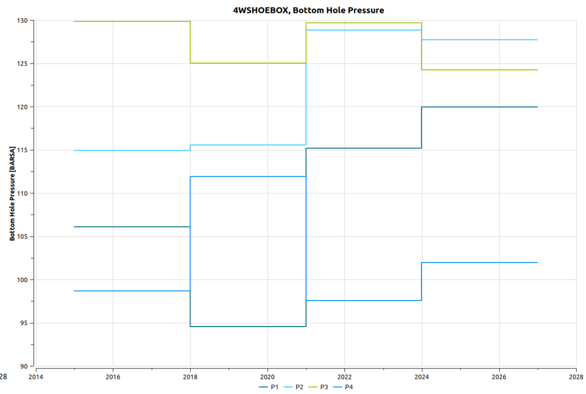
(b) Well water production rates

Figure B.3: Well production rates for 2 well segments with 8 control time steps

4 well segments

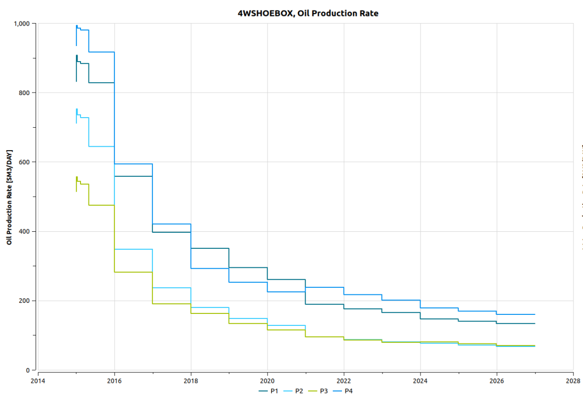


(a) Total oil and water production profile for 4 well segment configuration

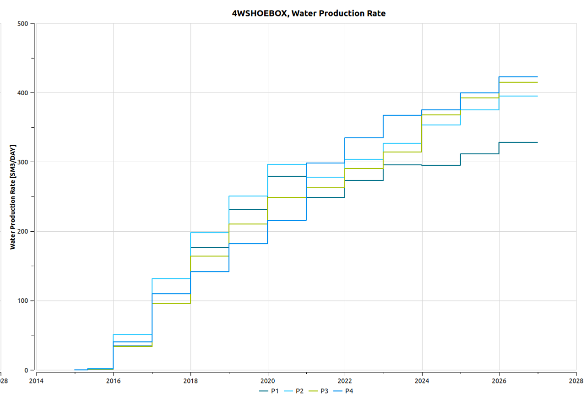


(b) Variation of BHP with time

Figure B.4: Final water and oil production profiles for 4 well segments and corresponding optimal BHP



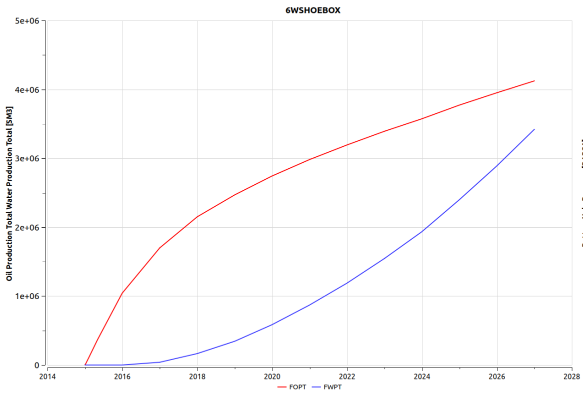
(a) Resulting Well oil production rate



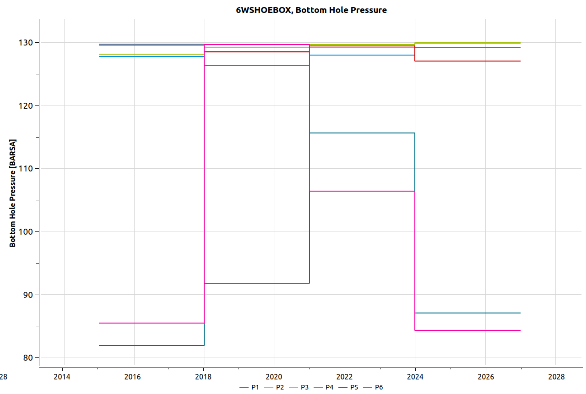
(b) Well water production rates

Figure B.5: Well production rates for 4 well segments with 4 control time steps

6 well segments

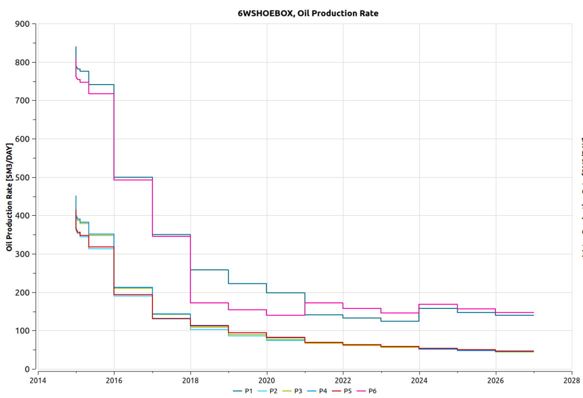


(a) Total oil and water production profile for 6 well segment configuration

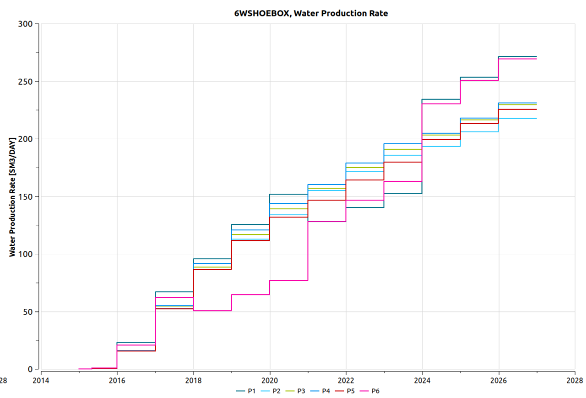


(b) Variation of BHP with time

Figure B.6: Final water and oil production profiles for 6 well segments and corresponding optimal BHP



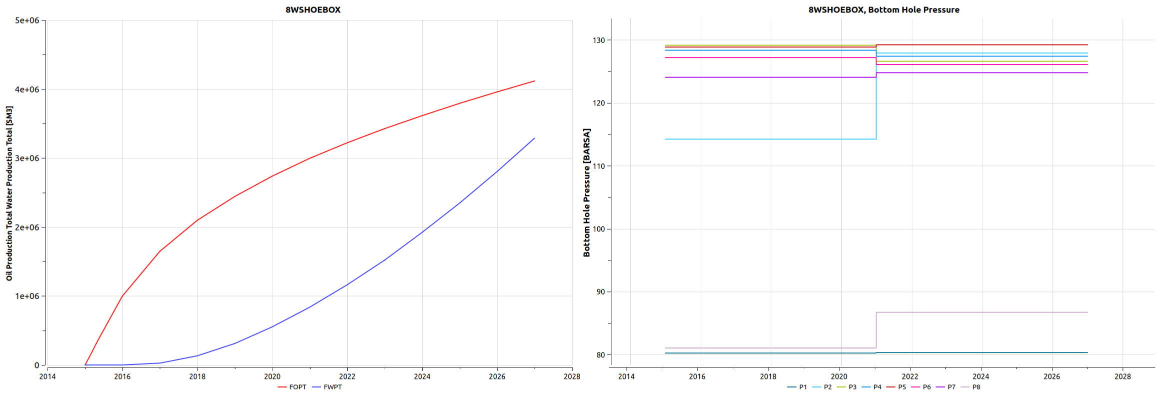
(a) Well oil production rates



(b) Well water production rates

Figure B.7: Well production rates for 6 well segments

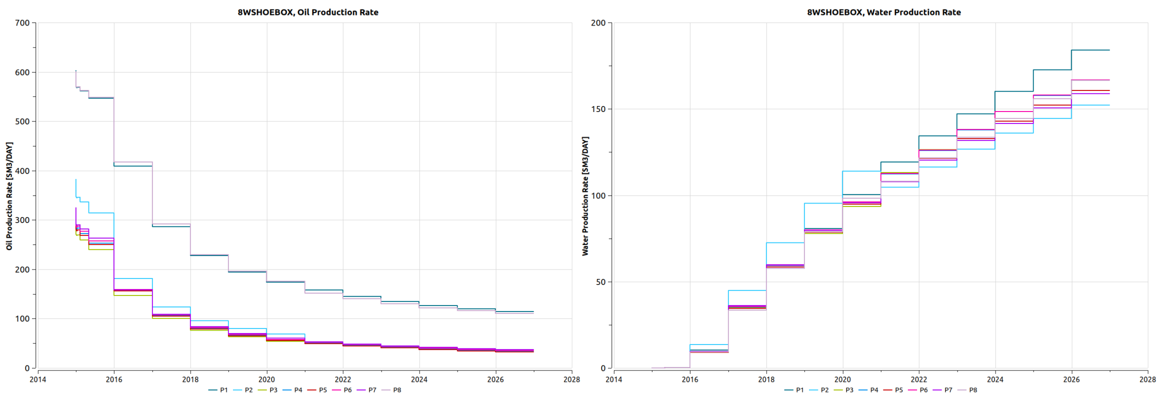
8 well segments



(a) Total oil and water production profile for 8 well segment configuration

(b) Variation of BHP with time

Figure B.8: Final water and oil production profiles for 6 well segments and corresponding optimal BHP



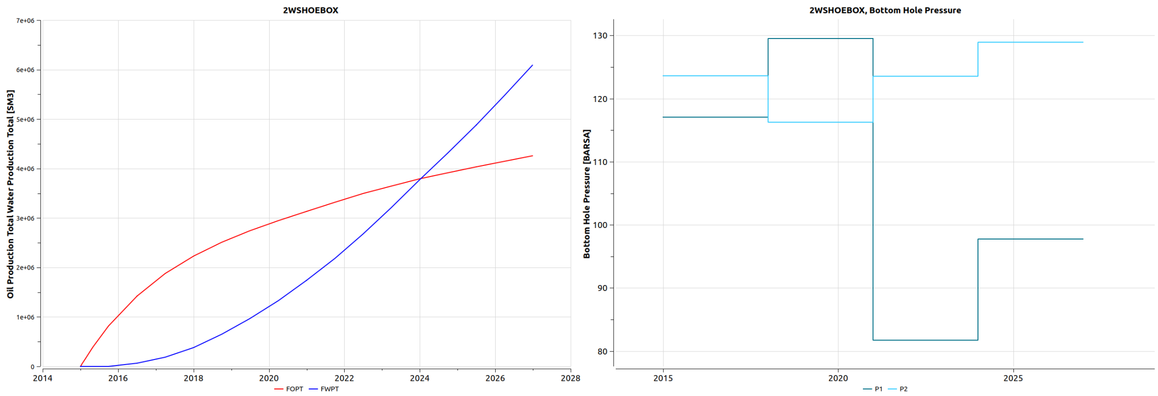
(a) Well oil production rates

(b) Well water production rates

Figure B.9: Well production rates for 8 well segments

CASE 2: Heterogeneous Reservoir with Aquifer support

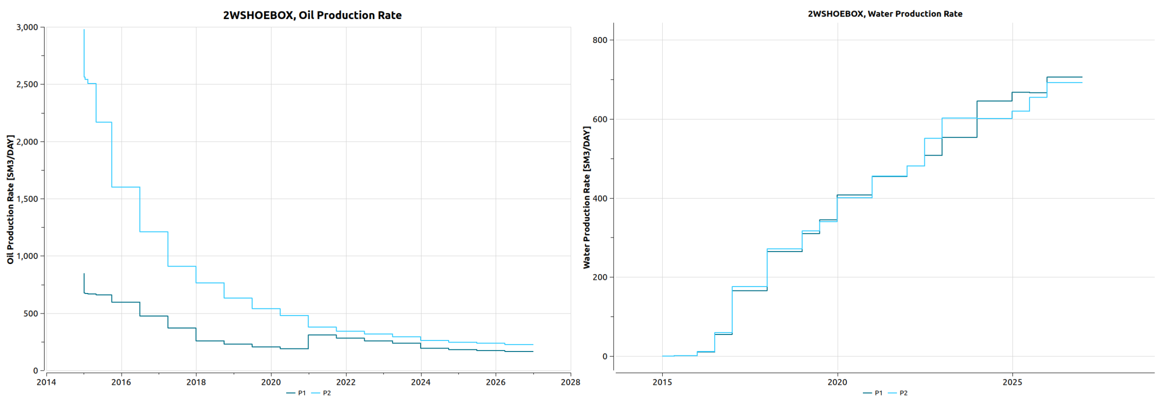
2 well segments



(a) Total oil and water production profile for 2 well segment configuration

(b) Variation of the BHP with time

Figure B.10: Final water and oil production profiles for 2 well segments and corresponding optimal BHP

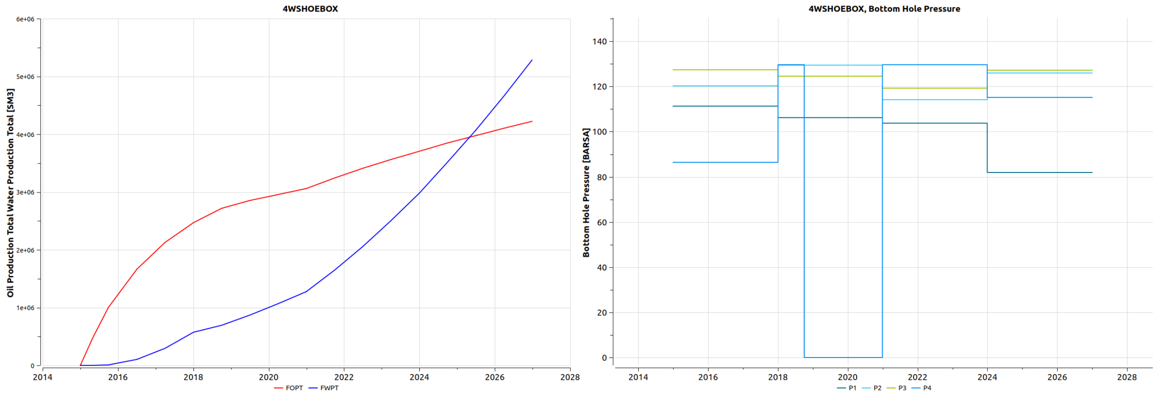


(a) Well oil production rates

(b) Well water production rates

Figure B.11: Well production rates for 2 well segments with 4 control time steps.

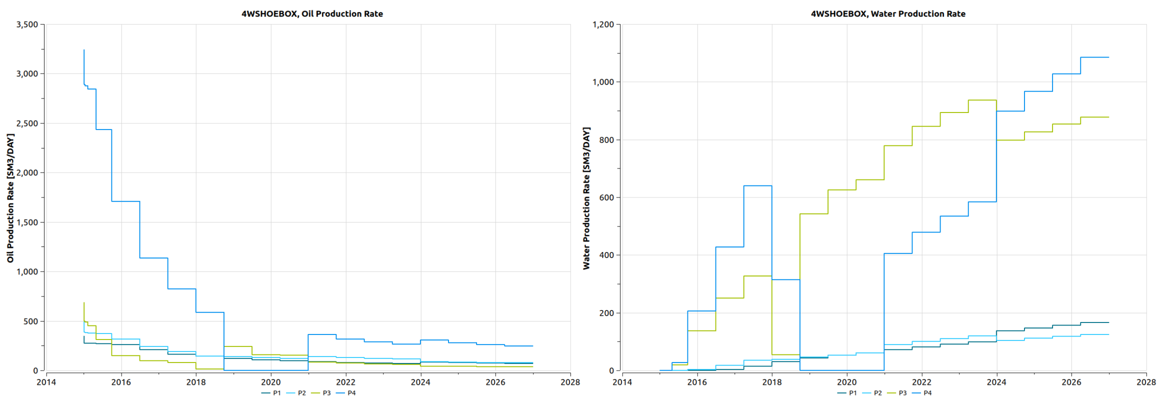
4 well segments



(a) Total oil and water production profile for 4 well segment configuration

(b) Variation of the BHP with time

Figure B.12: Final water and oil production profiles for 4 well segments and corresponding optimal BHP.

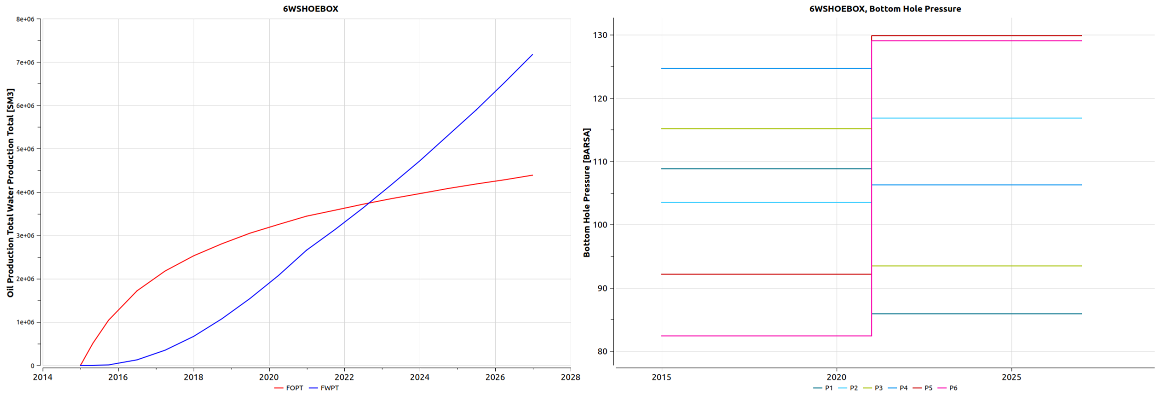


(a) Well oil production rates

(b) Well water production rates

Figure B.13: Well production rates for 4 well segments with 4 control time steps

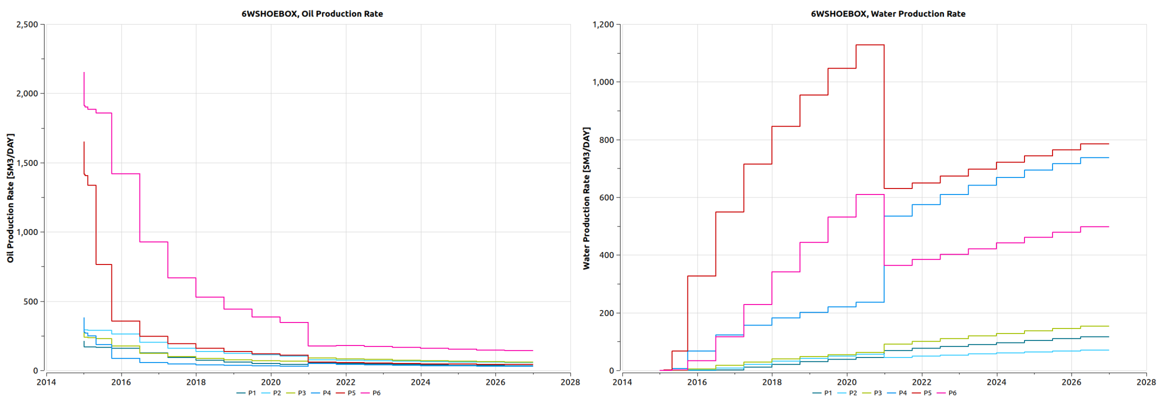
6 well segments



(a) Total oil and water production profile for 6 well segment configuration.

(b) Variation of the BHP with time.

Figure B.14: Final water and oil production profiles for 2 well segments and corresponding optimal BHP.

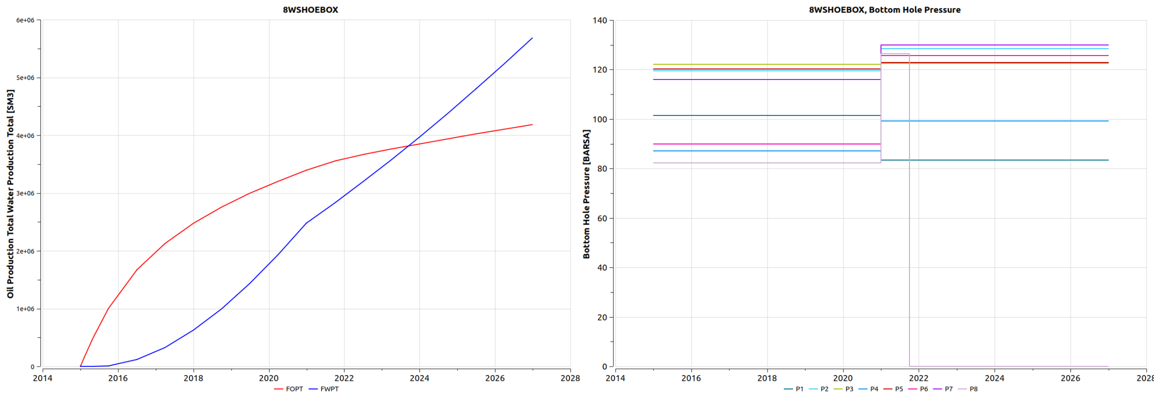


(a) Well oil production rates.

(b) Well water production rates.

Figure B.15: Well production rates for 6 well segments with 2 control time steps.

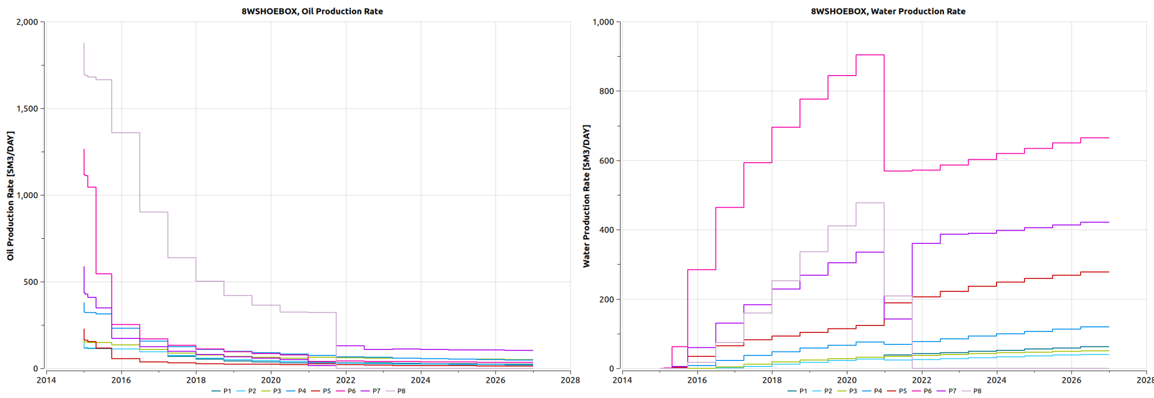
8 well segments



(a) Total oil and water production profile for 6 well segment configuration.

(b) Variation of the BHP with time.

Figure B.16: Final water and oil production profiles for 8 well segments and corresponding optimal BHP.



(a) Well oil production rates.

(b) Well water production rates.

Figure B.17: Well production rates for 8 well segments with 2 control time steps.

Appendix C

Driver Files

Appendix C is a compilation of the initial json driver file and the different json driver files generated from the workflow for the corresponding number of well segments. These files are used by FieldOpt to initialize the optimization runs.

Code listing C.1: Initial json driver file for a single well

```
{
    "Global": {
        "BookkeeperTolerance": 1e-08,
        "Name": "1WSHOEBOXMODEL"
    },
    "Model": {
        "ControlTimes": [
            0,
            365,
            730,
            1095,
            1460,
            1825,
            2190,
            2555,
            2920,
            3285,
            3650,
            4015,
            4380
        ],
        "Reservoir": {
            "Type": "FLOW"
        },
        "Wells": [
            {
```

```
                "Controls": [
                    {
                        "BHP": 110,
                        "IsVariable": true,
                        "Mode": "BHP",
                        "Rate": 5000,
                        "TimeStep": 0
                    }
                ],

                "DefinitionType": "WellSpline",
                "Group": "P",
                "Name": "P1",
                "PreferredPhase": "Oil",
                "SplinePointArray": [
                    {
                        "IsVariable": false,
                        "x": 425,
                        "y": 737.5,
                        "z": 2005.0
                    },
                    {
                        "IsVariable": false,
                        "x": 1025,
                        "y": 737.5,
                        "z": 2005.0
                    }
                ],
                "Type": "Producer",
                "WellboreRadius": 0.125
            }
        ]
    },
    "Optimizer": {
        "Constraints": [
            {
                "Max": 130,
                "Min": 80,
                "Type": "BHP",
                "Wells": [
                    "P1"
                ]
            }
        ],
```

```
        "Mode": "Maximize",
        "Objective": {
            "NPVComponents": [
                {
                    "COMMENT": "Coefficient: 60 $/barrel * 6.2898 barrel/sm3 = 377.388",
                    "Coefficient": 377.388,
                    "DiscountFactor": 0.08,
                    "Interval": "Yearly",
                    "Property": "CumulativeOilProduction",
                    "TimeStep": -1,
                    "UseDiscountFactor": true
                },
                {
                    "COMMENT": "Coefficient: -24 $/barrel * 6.2898 barrel/sm3 = -150.5992",
                    "Coefficient": -150.9552,
                    "DiscountFactor": 0.08,
                    "Interval": "Yearly",
                    "Property": "CumulativeWaterProduction",
                    "TimeStep": -1,
                    "UseDiscountFactor": true
                }
            ],
            "SeparateHorizontalAndVertical": false,
            "Type": "NPV",
            "UseWellCost": true,
            "WellCost": 7500,
            "WellCostXY": 0,
            "WellCostZ": 0
        },
        "Parameters": {
            "MaxGenerations": 25,
            "PSO-LearningFactor1": 2,
            "PSO-LearningFactor2": 2,
            "PSO-SwarmSize": 25,
            "PSO-VelocityScale": 0.25
        },
        "Type": "PSO"
    },
    "Simulator": {
        "ExecutionScript": "bash_flow",
        "FluidModel": "BlackOil",
        "ScheduleFile": "include/1WSHOEBOXMODEL_SCH.INC",
```

```
        "Type": "Flow"
    }
}
```

Code listing C.2: Generated json driver file for 2 well segment configuration

```
{
    "Global": {
        "BookkeeperTolerance": 1e-08,
        "Name": "2WSHOEBOXMODEL"
    },
    "Model": {
        "ControlTimes": [
            0,
            365,
            730,
            1095,
            1460,
            1825,
            2190,
            2555,
            2920,
            3285,
            3650,
            4015,
            4380
        ],
        "Reservoir": {
            "Type": "FLOW"
        },
        "Wells": [
            {
                "Controls": [
                    {
                        "BHP": 100,
                        "IsVariable": true,
                        "Mode": "BHP",
                        "TimeStep": 0
                    }
                ],
                "DefinitionType": "WellSpline",
                "Group": "P",
                "Name": "P1",
                "PreferredPhase": "Oil",
                "SplinePointArray": [
```

```
                    {
                        "IsVariable": false,
                        "x": 425.0,
                        "y": 730.0,
                        "z": 2005.0
                    },
                    {
                        "IsVariable": false,
                        "x": 712.5,
                        "y": 730.0,
                        "z": 2005.0
                    }
                ],
                "Type": "Producer",
                "WellboreRadius": 0.125
            },
            {
                "Controls": [
                    {
                        "BHP": 90,
                        "IsVariable": true,
                        "Mode": "BHP",
                        "TimeStep": 0
                    }
                ],
                "DefinitionType": "WellSpline",
                "Group": "P",
                "Name": "P2",
                "PreferredPhase": "Oil",
                "SplinePointArray": [
                    {
                        "IsVariable": false,
                        "x": 737.5,
                        "y": 730.0,
                        "z": 2005.0
                    },
                    {
                        "IsVariable": false,
                        "x": 1025.0,
                        "y": 730.0,
                        "z": 2005.0
                    }
                ],
                "Type": "Producer",
```

```
                "WellboreRadius": 0.125
            }
        ]
    },
    "Optimizer": {
        "Constraints": [
            {
                "Max": 130,
                "Min": 80,
                "Type": "BHP",
                "Wells": [
                    "P1",
                    "P2"
                ]
            }
        ],
        "Mode": "Maximize",
        "Objective": {
            "NPVComponents": [
                {
                    "COMMENT": "Coefficient: 60 $/barrel * 6.2898 barrel/sm3 = 377.388",
                    "Coefficient": 377.388,
                    "DiscountFactor": 0.08,
                    "Interval": "Yearly",
                    "Property": "CumulativeOilProduction",
                    "TimeStep": -1,
                    "UseDiscountFactor": true
                },
                {
                    "COMMENT": "Coefficient: -24 $/barrel * 6.2898 barrel/sm3 = -150.9552",
                    "Coefficient": -150.9552,
                    "DiscountFactor": 0.08,
                    "Interval": "Yearly",
                    "Property": "CumulativeWaterProduction",
                    "TimeStep": -1,
                    "UseDiscountFactor": true
                }
            ],
            "Type": "NPV",
            "UseWellCost": true,
            "WellCost": 75000,
            "WellCostXY": 0,
```

```
            "WellCostZ": 0
        },
        "Parameters": {
            "MaxGenerations": 25,
            "PSO-LearningFactor1": 2,
            "PSO-LearningFactor2": 2,
            "PSO-SwarmSize": 25,
            "PSO-VelocityScale": 0.25
        },
        "Type": "PSO"
    },
    "Simulator": {
        "ExecutionScript": "bash_flow",
        "FluidModel": "BlackOil",
        "ScheduleFile": "include/2WSHOEBOXMODEL_SCH.INC",
        "Type": "FLOW"
    }
}
```

Code listing C.3: Generated json driver file for 4 well segment configuration

```
{
    "Global": {
        "BookkeeperTolerance": 1e-08,
        "Name": "4WSHOEBOXMODEL"
    },
    "Model": {
        "ControlTimes": [
            0,
            365,
            730,
            1095,
            1460,
            1825,
            2190,
            2555,
            2920,
            3285,
            3650,
            4015,
            4380
        ],
        "Reservoir": {
            "Type": "FLOW"
        },
```

```json
        "Wells": [
            {
                "Controls": [
                    {
                        "BHP": 110,
                        "IsVariable": true,
                        "Mode": "BHP",
                        "TimeStep": 0
                    }
                ],
                "DefinitionType": "WellSpline",
                "Group": "P",
                "Name": "P1",
                "PreferredPhase": "Oil",
                "SplinePointArray": [
                    {
                        "IsVariable": false,
                        "x": 425.0,
                        "y": 730.0,
                        "z": 2005.0
                    },
                    {
                        "IsVariable": false,
                        "x": 556.2,
                        "y": 730.0,
                        "z": 2005.0
                    }
                ],
                "Type": "Producer",
                "WellboreRadius": 0.125
            },
            {
                "Controls": [
                    {
                        "BHP": 110,
                        "IsVariable": true,
                        "Mode": "BHP",
                        "TimeStep": 0
                    }
                ],
                "DefinitionType": "WellSpline",
                "Group": "P",
                "Name": "P2",
                "PreferredPhase": "Oil",
```

```
                "SplinePointArray": [
                    {
                        "IsVariable": false,
                        "x": 581.2,
                        "y": 730.0,
                        "z": 2005.0
                    },
                    {
                        "IsVariable": false,
                        "x": 712.5,
                        "y": 730.0,
                        "z": 2005.0
                    }vpn.ntnu.no
                ],
                "Type": "Producer",
                "WellboreRadius": 0.125
            },
            {
                "Controls": [
                    {
                        "BHP": 110,
                        "IsVariable": true,
                        "Mode": "BHP",
                        "TimeStep": 0
                    }
                ],
                "DefinitionType": "WellSpline",
                "Group": "P",
                "Name": "P3",
                "PreferredPhase": "Oil",
                "SplinePointArray": [
                    {
                        "IsVariable": false,
                        "x": 737.5,
                        "y": 730.0,
                        "z": 2005.0
                    },
                    {
                        "IsVariable": false,
                        "x": 868.8,
                        "y": 730.0,
                        "z": 2005.0
                    }
                ],
```

```
                "Type": "Producer",
                "WellboreRadius": 0.125
            },
            {
                "Controls": [
                    {
                        "BHP": 110,
                        "IsVariable": true,
                        "Mode": "BHP",
                        "TimeStep": 0
                    }
                ],
                "DefinitionType": "WellSpline",
                "Group": "P",
                "Name": "P4",
                "PreferredPhase": "Oil",
                "SplinePointArray": [
                    {
                        "IsVariable": false,
                        "x": 893.8,
                        "y": 730.0,
                        "z": 2005.0
                    },
                    {
                        "IsVariable": false,
                        "x": 1025.0,
                        "y": 730.0,
                        "z": 2005.0
                    }
                ],
                "Type": "Producer",
                "WellboreRadius": 0.125
            }
        ]
    },
    "Optimizer": {
        "Constraints": [
            {
                "Max": 130,
                "Min": 80,
                "Type": "BHP",
                "Wells": [
                    "P1",
                    "P2",
```

```
                    "P3",
                    "P4"
                ]
            }
        ],
        "Mode": "Maximize",
        "Objective": {
            "NPVComponents": [
                {
                    "COMMENT": "Coefficient: 60 $/barrel * 6.2898 barrel/sm3 =
                        377.388",
                    "Coefficient": 377.388,
                    "DiscountFactor": 0.08,
                    "Interval": "Yearly",
                    "Property": "CumulativeOilProduction",
                    "TimeStep": -1,
                    "UseDiscountFactor": true
                },
                {
                    "COMMENT": "Coefficient: -24 $/barrel * 6.2898 barrel/sm3 =
                        -150.9552",
                    "Coefficient": -150.9552,
                    "Divpn.ntnu.noscountFactor": 0.08,
                    "Interval": "Yearly",
                    "Property": "CumulativeWaterProduction",
                    "TimeStep": -1,
                    "UseDiscountFactor": true
                },
                {
                    "COMMENT": "Coefficient: -2 $/barrel * 6.2898 barrel/sm3 =
                        -12.580",
                    "Coefficient": -12.58,
                    "DiscountFactor": 0.08,
                    "Interval": "Yearly",
                    "Property": "CumulativeWaterInjection",
                    "TimeStep": -1,
                    "UseDiscountFactor": true
                }
            ],
            "SeparateHorizontalAndVertical": false,
            "Type": "NPV",
            "UseWellCost": true,
            "WellCost": 75000,
            "WellCostXY": 0,
```

```
            "WellCostZ": 0
        },
        "Parameters": {
            "MaxGenerations": 100,
            "PSO-LearningFactor1": 2,
            "PSO-LearningFactor2": 2,
            "PSO-SwarmSize": 50,
            "PSO-VelocityScale": 0.25
        },
        "Type": "PSO"
    },
    "Simulator": {
        "ExecutionScript": "bash_flow",
        "FluidModel": "BlackOil",
        "ScheduleFile": "include/4WSHOEBOXMODEL_SCH.INC",
        "Type": "FLOW"
    }
}
```

Code listing C.4: Generated json driver file for 6 well segment configuration

```
{
    "Global": {
        "BookkeeperTolerance": 1e-08,
        "Name": "6WSHOEBOXMODEL"
    },
    "Model": {
        "ControlTimes": [
            0,
            365,
            730,
            1095,
            1460,
            1825,
            2190,
            2555,
            2920,
            3285,
            3650,
            4015,
            4380
        ],
        "Reservoir": {
            "Type": "FLOW"
        },
```

```
        "Wells": [
            {
                "Controls": [
                    {
                        "BHP": 110  ,
                        "IsVariable": true,
                        "Mode": "BHP",
                        "TimeStep": 0
                    }
                ],
                "DefinitionType": "WellSpline",
                "Group": "P",
                "Name": "P1",
                "PreferredPhase": "Oil",
                "SplinePointArray": [
                    {
                        "IsVariable": false,
                        "x": 425.0,
                        "y": 730.0,
                        "z": 2005.0
                    },
                 i have to note that    {
                        "IsVariable": false,
                        "x": 504.2,
                        "y": 730.0,
                        "z": 2005.0
                    }
                ],
                "Type": "Producer",
                "WellboreRadius": 0.125
            },
            {
                "Controls": [
                    {
                        "BHP": 110 ,
                        "IsVariable": true,
                        "Mode": "BHP",
                        "TimeStep": 0
                    }
                ],
                "DefinitionType": "WellSpline",
                "Group": "P",
                "Name": "P2",
                "PreferredPhase": "Oil",
```

```
            "SplinePointArray": [
                {
                    "IsVariable": false,
                    "x": 529.2,
                    "y": 730.0,
                    "z": 2005.0
                },
                {
                    "IsVariable": false,
                    "x": 608.3,
                    "y": 730.0,
                    "z": 2005.0
                }
            ],
            "Type": "Producer",
            "WellboreRadius": 0.125
        },
        {
            "Controls": [
                {
                    "BHP": 110 ,
                    "IsVariable": true,
                    "Mode": "BHP",
                    "TimeStep": 0
                }
            ],
            "DefinitionType": "WellSpline",
            "Group": "P",
            "Name": "P3",
            "PreferredPhase": "Oil",
            "SplinePointArray": [
                {
                    "IsVariable": false,
                    "x": 633.3,
                    "y": 730.0,
                    "z": 2005.0
                },
                {
                    "IsVariable": false,
                    "x": 712.5,
                    "y": 730.0,
                    "z": 2005.0
                }
            ],
```

```
                "Type": "Producer",
                "WellboreRadius": 0.125
            },
            {
                "Controls": [
                    {
                        "BHP":110,
                        "IsVariable": true,
                        "Mode": "BHP",
                        "TimeStep": 0
                    }
                ],
                "DefinitionType": "WellSpline",
                "Group": "P",
                "Name": "P4",
                "PreferredPhase": "Oil",
                "SplinePointArray": [
                    {
                        "IsVariable": false,
                        "x": 737.5,
                        "y": 730.0,
                        "z": 2005.0
                    },
                    {
                        "IsVariable": false,
                        "x": 816.7,
                        "y": 730.0,
                        "z": 2005.0
                    }
                ],
                "Type": "Producer",
                "WellboreRadius": 0.125
            },
            {
                "Controls": [
                    {
                        "BHP": 110,
                        "IsVariable": true,
                        "Mode": "BHP",
                        "TimeStep": 0
                    }
                ],
                "DefinitionType": "WellSpline",
                "Group": "P",
```

```
                "Name": "P5",
                "PreferredPhase": "Oil",
                "SplinePointArray": [
                    {
                        "IsVariable": false,
                        "x": 841.7,
                        "y": 730.0,
                        "z": 2005.0
                    },
                    {
                        "IsVariable": false,
                        "x": 920.8,
                        "y": 730.0,
                        "z": 2005.0
                    }
                ],
                "Type": "Producer",
                "WellboreRadius": 0.125
            },
            {
                "Controls": [
                    {
                        "BHP": 110,
                        "IsVariable": true,
                        "Mode": "BHP",
                        "TimeStep": 0
                    }
                ],
                "DefinitionType": "WellSpline",
                "Group": "P",
                "Name": "P6",
                "PreferredPhase": "Oil",
                "SplinePointArray": [
                    {
                        "IsVariable": false,
                        "x": 945.8,
                        "y": 730.0,
                        "z": 2005.0
                    },
                    {
                        "IsVariable": false,
                        "x": 1025.0,
                        "y": 730.0,
                        "z": 2005.0
```

```
                    }
                ],
                "Type": "Producer",
                "WellboreRadius": 0.125
            }
        ]
    },
    "Optimizer": {
        "Constraints": [
            {
                "Max": 130,
                "Min": 80,
                "Type": "BHP",
                "Wells": [
                    "P1",
                    "P2",
                    "P3",
                    "P4",
                    "P5",
                    "P6"
                ]
            }
        ],
        "Mode": "Maximize",
        "Objective": {
            "NPVComponents": [
                {
                    "COMMENT": "Coefficient: 60 $/barrel * 6.2898 barrel/sm3 = 377.388",
                    "Coefficient": 377.388,
                    "DiscountFactor": 0.08,
                    "Interval": "Yearly",
                    "Property": "CumulativeOilProduction",
                    "TimeStep": -1,
                    "UseDiscountFactor": true
                },
                {
                    "COMMENT": "Coefficient: -24 $/barrel * 6.2898 barrel/sm3 = -150.5992",
                    "Coefficient": -150.9552,
                    "DiscountFactor": 0.08,
                    "Interval": "Yearly",
                    "Property": "CumulativeWaterProduction",
                    "TimeStep": -1,
```

```
                    "UseDiscountFactor": true
                }
            ],
            "SeparateHorizontalAndVertical": false,
            "Type": "NPV",
            "UseWellCost": true,
            "WellCost": 75000,
            "WellCostXY": 0,
            "WellCostZ": 0
        },
        "Parameters": {
            "MaxGenerations": 50,
            "PSO-LearningFactor1": 2,
            "PSO-LearningFactor2": 2,
            "PSO-SwarmSize": 75,
            "PSO-VelocityScale": 0.25
        },
        "Type": "PSO"
    },
    "Simulator": {
        "ExecutionScript": "bash_flow",
        "FluidModel": "BlackOil",
        "ScheduleFile": "include/6WSHOEBOXMODEL_SCH.INC",
        "Type": "Flow"
    }
}
```

Code listing C.5: Generated json driver file for 8 well segment configuration

```
{
    "Global": {
        "BookkeeperTolerance": 1e-08,
        "Name": "8WSHOEBOXMODEL"
    },
    "Model": {
        "ControlTimes": [
            0,
            365,
            730,
            1095,
            1460,
            1825,
            2190,
            2555,
            2920,
```

```
            3285,
            3650,
            4015,
            4380
        ],
        "Reservoir": {
            "Type": "FLOW"
        },
        "Wells": [
            {
                "Controls": [
                    {
                        "BHP": 110,
                        "IsVariable": true,
                        "Mode": "BHP",
                        "TimeStep": 0
                    }
                ],
                "DefinitionType": "WellSpline",
                "Group": "P",
                "Name": "P1",
                "PreferredPhase": "Oil",
                "SplinePointArray": [
                    {
                        "IsVariable": false,
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                        "z": 2005.0
                    },
                    {
                        "IsVariable": false,
                        "x": 478.1,
                        "y": 730.0,
                        "z": 2005.0
                    }
                ],
                "Type": "Producer",
                "WellboreRadius": 0.125
            },
            {
                "Controls": [
                    {
                        "BHP": 110,
                        "IsVariable": true,
```

```
                        "Mode": "BHP",
                        "TimeStep": 0
                    }
                ],
                "DefinitionType": "WellSpline",
                "Group": "P",
                "Name": "P2",
                "PreferredPhase": "Oil",
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                    {
                        "IsVariable": false,
                        "x": 503.1,
                        "y": 730.0,
                        "z": 2005.0
                    },
                    {
                        "IsVariable": false,
                        "x": 556.2,
                  i have to note that       "y": 730.0,
                        "z": 2005.0
                    }
                ],
                "Type": "Producer",
                "WellboreRadius": 0.125
            },
            {
                "Controls": [
                    {
                        "BHP": 110,
                        "IsVariable": true,
                        "Mode": "BHP",
                        "TimeStep": 0
                    }
                ],
                "DefinitionType": "WellSpline",
                "Group": "P",
                "Name": "P3",
                "PreferredPhase": "Oil",
                "SplinePointArray": [
                    {
                        "IsVariable": false,
                        "x": 581.2,
                        "y": 730.0,
                        "z": 2005.0
```

```
                    },
                    {
                        "IsVariable": false,
                        "x": 634.4,
                        "y": 730.0,
                        "z": 2005.0
                    }
                ],
                "Type": "Producer",
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            },
            {
                "Controls": [
                    {
                        "BHP": 110,
                        "IsVariable": true,
                        "Mode": "BHP",
                        "TimeStep": 0
                    }
                ],
                "DefinitionType": "WellSpline",
                "Group": "P",
                "Name": "P4",
                "PreferredPhase": "Oil",
                "SplinePointArray": [
                    {
                        "IsVariable": false,
                        "x": 659.4,
                        "y": 730.0,
                        "z": 2005.0
                    },
                    {
                        "IsVariable": false,
                        "x": 712.5,
                        "y": 730.0,
                        "z": 2005.0
                    }
                ],
                "Type": "Producer",
                "WellboreRadius": 0.125
            },
            {
                "Controls": [
                    {
```

```
                        "BHP": 110,
                        "IsVariable": true,
                        "Mode": "BHP",
                        "TimeStep": 0
                    }
                ],
                "DefinitionType": "WellSpline",
                "Group": "P",
                "Name": "P5",
                "PreferredPhase": "Oil",
                "SplinePointArray": [
                    {
                        "IsVariable": false,
                        "x": 737.5,
                        "y": 730.0,
                        "z": 2005.0
                    },
                    {
                        "IsVariable": false,
                        "x": 790.6,
                        "y": 730.0,
                        "z": 2005.0
                    }
                ],
                "Type": "Producer",
                "WellboreRadius": 0.125
            },
            {
                "Controls": [
                    {
                        "BHP": 110,
                        "IsVariable": true,
                        "Mode": "BHP",
                        "TimeStep": 0
                    }
                ],
                "DefinitionType": "WellSpline",
                "Group": "P",
                "Name": "P6",
                "PreferredPhase": "Oil",
                "SplinePointArray": [
                    {
                        "IsVariable": false,
                        "x": 815.6,
```

```
                        "y": 730.0,
                        "z": 2005.0
                    },
                    {
                        "IsVariable": false,
                        "x": 868.8,
                        "y": 730.0,
                        "z": 2005.0
                    }
                ],
                "Type": "Producer",
                "WellboreRadius": 0.125
            },
            {
                "Controls": [
                    {
                        "BHP": 110,
                        "IsVariable": true,
                        "Mode": "BHP",
                        "TimeStep": 0
                    }
                ],
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                "Group": "P",
                "Name": "P7",
                "PreferredPhase": "Oil",
                "SplinePointArray": [
                    {
                        "IsVariable": false,
                        "x": 893.8,
                        "y": 730.0,
                        "z": 2005.0
                    },
                    {
                        "IsVariable": false,
                        "x": 946.9,
                        "y": 730.0,
                        "z": 2005.0
                    }
                ],
                "Type": "Producer",
                "WellboreRadius": 0.125
            },
            {
```

```
                "Controls": [
                    {
                        "BHP": 110,
                        "IsVariable": true,
                        "Mode": "BHP",
                        "TimeStep": 0
                    }
                ],
                "DefinitionType": "WellSpline",
                "Group": "P",
                "Name": "P8",
                "PreferredPhase": "Oil",
                "SplinePointArray": [
                    {
                        "IsVariable": false,
                        "x": 971.9,
                        "y": 730.0,
                        "z": 2005.0
                    },
                    {
                        "IsVariable": false,
                        "x": 1025.0,
                        "y": 730.0,
                        "z": 2005.0
                    }
                ],
                "Type": "Producer",
                "WellboreRadius": 0.125
            }
        ]
    },
    "Optimizer": {
        "Constraints": [
            {
                "Max": 130,
                "Min": 80,
                "Type": "BHP",
                "Wells": [
                    "P1",
                    "P2",
                    "P3",
                    "P4",
                    "P5",
                    "P6",
```

```
                    "P7",
                    "P8"
                ]
            }
        ],
        "Mode": "Maximize",
        "Objective": {
            "NPVComponents": [
                {
                    "COMMENT": "Coefficient: 60 $/barrel * 6.2898 barrel/sm3 = 377.388",
                    "Coefficient": 377.388,
                    "DiscountFactor": 0.08,
                    i have to note that "Interval": "Yearly",
                    "Property": "CumulativeOilProduction",
                    "TimeStep": -1,
                    "UseDiscountFactor": true
                },
                {
                    "COMMENT": "Coefficient: -24 $/barrel * 6.2898 barrel/sm3 = -150.5992",
                    "Coefficient": -150.9552,
                    "DiscountFactor": 0.08,
                    "Interval": "Yearly",
                    "Property": "CumulativeWaterProduction",
                    i have to note that "TimeStep": -1,
                    "UseDiscountFactor": true
                },
            ],
            "SeparateHorizontalAndVertical": false,
            "Type": "NPV",
            "UseWellCost": true,
            "WellCost": 75000,
            "WellCostXY": 0,
            "WellCostZ": 0
        },
        "Parameters": {
            "MaxGenerations": 100,
            "PSO-LearningFactor1": 2,
            "PSO-LearningFactor2": 2,
            "PSO-SwarmSize": 100,
            "PSO-VelocityScale": 0.25
        },
        "Type": "PSO"
```

```
    },
    "Simulator": {
        "ExecutionScript": "bash_flow",
        "FluidModel": "BlackOil",
        "ScheduleFile": "include/8WSHOEBOXMODEL_SCH.INC",
        "Type": "Flow"
    }
}
```

Appendix D

Master Thesis Agreement

Masteravtale/hovedoppgaveavtale

Sist oppdatert 11. november 2020

Fakultet	**Fakultet for ingeniørvitenskap**
Institutt	**Institutt for geovitenskap og petroleum**
Studieprogram	**MSG1**
Emnekode	**TPG4920**

Studenten

Etternavn, fornavn	**Nakibuule, Maria Assumpta**
Fødselsdato	**15.09.1994**
E-postadresse ved NTNU	**marinaki@stud.ntnu.no**

Tilknyttede ressurser

Veileder	**Carl Fredrik Berg**
Eventuelle medveiledere	**Thiago Lima Silva, Mathias Bellout**
Eventuelle medstudenter	

Oppgaven

Oppstartsdato	**01.02.2021**
Leveringsfrist	**14.06.2021**
Oppgavens arbeidstittel	**Optimal Well Inflow Modelling**
Problembeskrivelse	**Modelling pressure distribution along well bore for optimal reservoir drainage that shall form the basis of designing the settings for inflow control devices. Pressure distribution modelling is done using reservoir models and implementation of FieldOpt software.**

Risikovurdering og datahåndtering

Skal det gjennomføres risikovurdering? **Dersom «ja», har det blitt gjennomført?**	**Nei** **Nei**
Skal det søkes om godkjenninger? (REK*, NSD)**	**Nei**
Skal det skrives en konfidensialitetsavtale i forbindelse med oppgaven? **Hvis «ja», har det blitt gjort?**	**Nei** **Nei**

* Regionale komiteer for medisinsk og helsefaglig forskningsetikk (https://rekportalen.no)

** Norsk senter for forskningsdata (https://nsd.no/)

Eventuelle emner som skal inngå i mastergraden

Retningslinjer - rettigheter og plikter

Formål

Avtale om veiledning av masteroppgaven/hovedoppgaven er en samarbeidsavtale mellom student, veileder og institutt. Avtalen regulerer veiledningsforholdet, omfang, art og ansvarsfordeling.

Studieprogrammet og arbeidet med oppgaven er regulert av Universitets- og høgskoleloven, NTNUs studieforskrift og gjeldende studieplan. Informasjon om emnet, som oppgaven inngår i, finner du i emnebeskrivelsen.

Veiledning

Studenten har ansvar for å

- Avtale veiledningstimer med veileder innenfor rammene master-/hovedoppgaveavtalen gir.
- Utarbeide framdriftsplan for arbeidet i samråd med veileder, inkludert veiledningsplan.
- Holde oversikt over antall brukte veiledningstimer sammen med veileder.
- Gi veileder nødvendig skriftlig materiale i rimelig tid før veiledning.
- Holde instituttet og veileder orientert om eventuelle forsinkelser.
- Inkludere eventuell(e) medstudent(er) i avtalen.

Veileder har ansvar for å

- Avklare forventninger om veiledningsforholdet.
- Sørge for at det søkes om eventuelle nødvendige godkjenninger (etikk, personvernhensyn).
- Gi råd om formulering og avgrensning av tema og problemstilling, slik at arbeidet er gjennomførbart innenfor normert eller avtalt studietid.
- Drøfte og vurdere hypoteser og metoder.
- Gi råd vedrørende faglitteratur, kildemateriale, datagrunnlag, dokumentasjon og eventuelt ressursbehov.
- Drøfte framstillingsform (eksempelvis disposisjon og språklig form).
- Drøfte resultater og tolkninger.
- Holde seg orientert om progresjonen i studentens arbeid i henhold til avtalt tids- og arbeidsplan, og følge opp studenten ved behov.
- Sammen med studenten holde oversikt over antall brukte veiledningstimer.

Instituttet har ansvar for å

- Sørge for at avtalen blir inngått.
- Finne og oppnevne veileder(e).
- Inngå avtale med annet institutt/ fakultet/institusjon dersom det er oppnevnt ekstern medveileder.
- I samarbeid med veileder holde oversikt over studentens framdrift, antall brukte veiledningstimer, og følge opp dersom studenten er forsinket i henhold til avtalen.
- Oppnevne ny veileder og sørge for inngåelse av ny avtale dersom:
  - Veileder blir fraværende på grunn av eksempelvis forskningstermin, sykdom, eller reiser.
  - Student eller veileder ber om å få avslutte avtalen fordi en av partene ikke følger den.
  - Andre forhold gjør at partene finner det hensiktsmessig med ny veileder.
- Gi studenten beskjed når veiledningsforholdet opphører.
- Informere veileder(e) om ansvaret for å ivareta forskningsetiske forhold, personvernhensyn og veiledningsetiske forhold.
- Ønsker student, eller veileder, å bli løst fra avtalen må det søkes til instituttet. Instituttet må i et slikt tilfelle oppnevne ny veileder.

Avtaleskjemaet skal godkjennes når retningslinjene er gjennomgått.

Godkjent av

Maria Assumpta Nakibuule
Student

18.01.2021
Digitalt godkjent

Carl Fredrik Berg
Veileder

19.01.2021
Digitalt godkjent

Turid Oline Uvsløkk
Institutt

26.01.2021
Digitalt godkjent

Fastsatt av Rektor 20.01.2012

STANDARDAVTALE

om utføring av masteroppgave/prosjektoppgave (oppgave) i samarbeid med bedrift/ekstern virksomhet (bedrift).

Avtalen er ufravikelig for studentoppgaver ved NTNU som utføres i samarbeid med bedrift.

Partene har ansvar for å klarere eventuelle immaterielle rettigheter som tredjeperson (som ikke er part i avtalen) kan ha til prosjektbakgrunn før bruk i forbindelse med utførelse av oppgaven.

Avtale mellom

Student: **Nakibuule, Maria Assumpta**	født: **15.09.1994**

Veileder ved NTNU: **Carl Fredrik Berg**

Bedrift/ekstern virksomhet: **Ranold AS**

og

Norges teknisk-naturvitenskapelige universitet (NTNU) v/instituttleder

om bruk og utnyttelse av resultater fra masteroppgave/prosjektoppgave.

1. Utførelse av oppgave

Studenten skal utføre masteroppgave i samarbeid med

Ranold AS

bedrift/ekstern virksomhet

01.02.2021- 14.06.2021

startdato – sluttdato

Oppgavens tittel er:

Optimal Well Inflow Modelling

Ansvarlig veileder ved NTNU har det overordnede faglige ansvaret for utforming og godkjenning av prosjektbeskrivelse og studentens læring.

2. Bedriftens plikter

Bedriften skal stille med en kontaktperson som har nødvendig veiledningskompetanse og gi studenten tilstrekkelig veiledning i samarbeid med veileder ved NTNU. Bedriftens kontaktperson er:

Morten Hansen Jondahl

Formålet med oppgaven er studentarbeid. Oppgaven utføres som ledd i studiet, og studenten skal ikke motta lønn eller lignende godtgjørelse fra bedriften. Bedriften skal dekke følgende utgifter knyttet til utførelse av oppgaven:

<div class="ExternalClass8585FC78CE7C43A19E99A6B843CCE452">none</div>

3. Partenes rettigheter

a) Studenten

Studenten har opphavsrett til oppgaven. Alle immaterielle rettigheter til resultater av oppgaven skapt av studenten alene gjennom oppgavearbeidet, eies av studenten med de reservasjoner som følger av punktene b) og c) nedenfor.

Studenten har rett til å inngå egen avtale med NTNU om publisering av sin oppgave i NTNUs institusjonelle arkiv på internett. Studenten har også rett til å publisere oppgaven eller deler av den i andre sammenhenger dersom det ikke i denne avtalen er avtalt begrensninger i adgangen til å publisere, jf punkt 4.

b) Bedriften

Der oppgaven bygger på, eller videreutvikler materiale og/eller metoder (prosjektbakgrunn) som eies av bedriften, eies prosjektbakgrunnen fortsatt av bedriften. Eventuell utnyttelse av videreutviklingen, som inkluderer prosjektbakgrunnen, forutsetter at det inngås egen avtale om dette mellom student og bedrift.

Bedriften skal ha rett til å benytte resultatene av oppgaven i egen virksomhet dersom utnyttelsen faller innenfor bedriftens virksomhetsområde. Dette skal fortolkes i samsvar med begrepets innhold i Arbeidstakeroppfinnelsesloven[1] § 4. Retten er ikke-eksklusiv.

[1] Lov av 17. april 1970 om retten til oppfinnelser som er gjort av arbeidstakere

Bruk av resultatet av oppgaven utenfor bedriften sitt virksomhetsområde, jf avsnittet ovenfor, forutsetter at det inngås egen avtale mellom studenten og bedriften. Avtale mellom bedrift og student om rettigheter til oppgaveresultater som er skapt av studenten, skal inngås skriftlig og er ikke gyldig inngått før NTNU har mottatt skriftlig gjenpart av avtalen.

Dersom verdien av bruken av resultatene av oppgaven er betydelig, dvs overstiger NOK 100.000 (kommentert i veiledningen[2] til avtalen), er studenten berettiget til et rimelig vederlag. Arbeidstakeroppfinnelsesloven § 7 gis anvendelse på vederlagsberegningen. Denne vederlagsretten gjelder også for ikke-patenterbare resultater. Fristbestemmelsene i § 7 gis tilsvarende anvendelse.

c) NTNU

De innleverte eksemplarer/filer av oppgaven med vedlegg, som er nødvendig for sensur og arkivering ved NTNU, tilhører NTNU. NTNU får en vederlagsfri bruksrett til resultatene av oppgaven, inkludert vedlegg til denne, og kan benytte dette til undervisnings- og forskningsformål med de eventuelle begrensninger som fremgår i punkt 4.

4. Utsatt offentliggjøring

Hovedregelen er at studentoppgaver skal være offentlige. I særlige tilfeller kan partene bli enig om at hele eller deler av oppgaven skal være undergitt utsatt offentliggjøring i maksimalt 3 år, dvs. ikke tilgjengelig for andre enn student og bedrift i denne perioden.

Oppgaven skal være undergitt utsatt offentliggjøring i

Ikke aktuelt

Behovet for utsatt offentliggjøring er begrunnet ut fra følgende:

De delene av oppgaven som ikke er undergitt utsatt offentliggjøring, kan publiseres i NTNUs institusjonelle arkiv, jf punkt 3 a), andre avsnitt.

http://www.lovdata.no/all/hl-19700417-021.html

[2] Veiledning til NTNUs standardavtale om masteroppgave/prosjektoppgave i samarbeid med bedrift http://www.ntnu.no/studier/standardavtaler

Selv om oppgaven er undergitt utsatt offentliggjøring, skal bedriften legge til rette for at studenten kan benytte hele eller deler av oppgaven i forbindelse med jobbsøknader samt videreføring i et doktorgradsarbeid.

5. Generelt

Denne avtalen skal ha gyldighet foran andre avtaler som er eller blir opprettet mellom to av partene som er nevnt ovenfor. Dersom student og bedrift skal inngå avtale om konfidensialitet om det som studenten får kjennskap til i bedriften, skal NTNUs standardmal for konfidensialitetsavtale benyttes. Eventuell avtale om dette skal vedlegges denne avtalen.

Eventuell uenighet som følge av denne avtalen skal søkes løst ved forhandlinger. Hvis dette ikke fører frem, er partene enige om at tvisten avgjøres ved voldgift i henhold til norsk lov. Tvisten avgjøres av sorenskriveren ved Sør-Trøndelag tingrett eller den han/hun oppnevner.

Denne avtale er underskrevet i 4 - fire - eksemplarer hvor partene skal ha hvert sitt eksemplar. Avtalen er gyldig når den er godkjent og underskrevet av NTNU v/instituttleder.

18.01.2021	Maria Assumpta Nakibuule

Elektronisk godkjent, dato — student

19.01.2021	Carl Fredrik Berg

Elektronisk godkjent, dato — veileder ved NTNU

~~26.01.2021~~ 12.02.2021	~~Turid Oline Uvsløkk~~

Elektronisk godkjent, dato — instituttleder, NTNU — institutt

26.01.2021	Trygve Randen

Elektronisk godkjent, dato — for bedriften/institusjonen

stempel og signatur

NTNU

Master`s Agreement / Main Thesis Agreement

Faculty	Faculty of Engineering
Institute	Department of Geoscience and Petroleum
Programme Code	MSG1
Course Code	TPG4920

Personal Information

Surname, First Name	Nakibuule, Maria Assumpta
Date of Birth	15.09.1994
Email	marinaki@stud.ntnu.no

Supervision and Co-authors

Supervisor	Carl Fredrik Berg
Co-supervisors (if applicable)	Thiago Lima Silva, Mathias Bellout
Co-authors (if applicable)	

The Master`s thesis

Starting Date	01.02.2021
Submission Deadline	14.06.2021
Thesis Working Title	Optimal Well Inflow Modelling
Problem Description	Modelling pressure distribution along well bore for optimal reservoir drainage that shall form the basis of designing the settings for inflow control devices. Pressure distribution modelling is done using reservoir models and implementation of FieldOpt software.

Risk Assessment and Data Management

Will you conduct a Risk Assessment? **If "Yes", Is the Risk Assessment Conducted?**	**No** **No**
Will you Apply for Data Management? **(REK*, NSD**)**	**No**
Will You Write a Confidentiality Agreement? **If "Yes", Is the Confidentiality Agreement Conducted?**	**No** **No**

* REK -- https://rekportalen.no/

** Norwegian Centre for Research Data (https://nsd.no/nsd/english/index.html)

Topics to be included in the Master`s Degree (if applicable)

Guidelines – Rights and Obligations

Purpose

The Master's Agreement/ Main Thesis Agreement is an agreement between the student, supervisor, and department. The agreement regulates supervision conditions, scope, nature, and responsibilities concerning the thesis.

The study programme and the thesis are regulated by the Universities and University Colleges Act, NTNU's study regulations, and the current curriculum for the study programme.

Supervision

The student is responsible for

- Arranging the supervision within the framework provided by the agreement.
- Preparing a plan of progress in cooperation with the supervisor, including a supervision schedule.
- Keeping track of the counselling hours.
- Providing the supervisor with the necessary written material in a timely manner before the supervision.
- Keeping the institute and supervisor informed of any delays.
- Adding fellow student(s) to the agreement, if the thesis has more than one author.

The supervisor is responsible for

- Clarifying expectations and how the supervision should take place.
- Ensuring that any necessary approvals are acquired (REC, ethics, privacy).
- Advising on the demarcation of the topic and the thesis statement to ensure that the work is feasible within agreed upon time frame.
- Discussing and evaluating hypotheses and methods.
- Advising on literature, source material, data, documentation, and resource requirements.
- Discussing the layout of the thesis with the student (disposition, linguistic form, etcetera).
- Discussing the results and the interpretation of them.
- Staying informed about the work progress and assist the student if necessary.
- Together with the student, keeping track of supervision hours spent.

The institute is responsible for

- Ensuring that the agreement is entered into.
- Find and appoint supervisor(s).
- Enter into an agreement with another department / faculty / institution if there is an external co-supervisor.
- In cooperation with the supervisor, keep an overview of the student's progress, the number of supervision hours. spent, and assist if the student is delayed by appointment.
- Appoint a new supervisor and arrange for a new agreement if:
  - The supervisor will be absent due to research term, illness, travel, etcetera.
  - The student or supervisor requests to terminate the agreement due to lack of adherence from either party.
  - Other circumstances where it is appropriate with a new supervisor.
- Notify the student when the agreement terminates.
- Inform supervisors about the responsibility for safeguarding ethical issues, privacy and guidance ethics
- Should the cooperation between student and supervisor become problematic, either party may apply to the department to be freed from the agreement. In such occurrence, the department must appoint a new supervisor

This Master`s agreement must be signed when the guidelines have been reviewed.

Signatures

Maria Assumpta Nakibuule
Student

18.01.2021
Digitally approved

Carl Fredrik Berg
Supervisor

19.01.2021
Digitally approved

Turid Oline Uvsløkk
Department

26.01.2021
Digitally approved

NTNU

By order of Rector: 20 January 2012

STANDARD AGREEMENT

concerning work on a master's thesis/project assignment (academic work) done in cooperation with a company/external organization (organization).

This is the authoritative agreement that governs academic work by students at the Norwegian University of Science and Technology (NTNU) that is carried out in cooperation with an organization.

The involved parties have the responsibility to clarify whether or not a third party (that is not a party to this agreement) may have intellectual property rights to the project background before the latter is used in connection with the academic work.

Agreement between

Student: **Nakibuule, Maria Assumpta**	Date of birth: **15.09.1994**

Supervisor at NTNU: **Carl Fredrik Berg**

Company/external organization: **Ranold AS**

and

Norwegian University of Science and Technology (NTNU), represented by the Head of Department

concerning the use and exploitation of the results from a master's thesis/project assignment.

1. Description of the academic work

The student is to carry out Master`s thesis in cooperation with

Ranold AS

company/external organization

01.02.2021– 14.06.2021

starting date – completion date

Title of the academic work:

Optimal Well Inflow Modelling

The responsible supervisor at NTNU has overall academic responsibility for structuring and approving the description of the academic work and the student's learning.

2. Responsibilities of the organization

The organization is to appoint a contact person who has the necessary experience in supervision and will give the student adequate supervision in cooperation with the supervisor at NTNU. The contact person at the organization is:

Morten Hansen Jondahl

The purpose of completing the academic work is academic training for the student. The academic work is part of a student's course of study and the student is not to receive wages or similar compensation from the organization. The organization agrees to cover the following expenses that are associated with carrying out the academic work:

<div class="ExternalClass8585FC78CE7C43A19E99A6B843CCE452">none</div>

3. Rights of the parties

a) The student

The student holds the copyright to his/her academic work. All intellectual property rights to the results of the academic work done by the student alone during the academic work are held by the student with the reservations stated in points b) and c) below.

The student has the right to enter into an agreement with NTNU concerning the publication of his/her academic work in NTNU's institutional archive on the Internet. The student has also the right to publish his/her academic work or parts of it in other media providing the present agreement has not imposed restriction concerning publication, cf. Clause 4.

b) the organization

If the academic work is based on or develops materials and/or methods (project background) that are owned by the organization, the project background is owned by the organization. If the development work that includes the project background can be commercially exploited, it is assumed that a separate agreement will be drawn up concerning this between the student and the organization.

The organization is to have the right to use the results of the academic work in its own activities providing the commercial exploitation falls within the activities of the organization. This is to be interpreted in accordance with the terminology used in Section 4 of the Act Respecting the Right to Employees' Inventions (Arbeidstakeroppfinnelsesloven). This right is non-exclusive.

The use of the results of the academic work outside of the activities of the organization, cf. the last paragraph above, assumes that a separate agreement will be drawn up between the student and the organization. The agreement between the student and the organization concerning the rights to the results of the academic work produced by the student is to be in writing and the agreement is invalid until NTNU has received a copy of the agreement in writing.

If the value of the results of the academic work is considerable, i.e. it is more than NOK 100 000, the student is entitled to receive reasonable compensation. Section 7 of the Act Respecting the Right to Employees' Inventions states how the amount of compensation is to be calculated. This right to compensation also applies to non-patentable results. Section 7 of the Act also states the applicable deadlines.

c) NTNU

All copies of the submitted academic work/files containing the academic work and any appendices that are necessary for determining a grade and for the records at NTNU, are the property of NTNU. The academic work and any appendices to it can be used by NTNU for educational and scientific purposes free of charge, except when the restrictions specified in Clause 4 are applicable.

4. Delayed publication

The general rule is that academic work by students is to be available in the public domain. If there are specific circumstances, the parties can agree to delay the publication of all or part of the academic work for a maximum of 3 years, i.e. the work is not available for other students or organizations during this period.

The academic work is subject to delayed publication for:

Not applicable

The grounds for delayed publication are as follows:

The parts of the academic work that are not subject to delayed publication can be published in NTNU's institutional archive, cf. Clause 3 a) second paragraph.

Even if the academic work is subject to delayed publication, the organization is to make it possible for the student to use all or part of his/her academic work in connection with a job application or follow-up work in connection with doctoral study.

5. General

This agreement takes precedence over any other agreements that are or will be entered into by two of the parties mentioned above. In case the student and the organization are to enter into a confidentiality agreement concerning information the student obtains while he/she is at the organization, NTNU's template for a confidentiality agreement is to be used for this purpose. If there is such an agreement, it is to be appended to the present agreement.

Should there be any dispute relating to this agreement, it should be resolved by negotiation. If this does not lead to a solution, the parties agree to the matter being resolved by arbitration in accordance with Norwegian law. Any such dispute is to be decided by Sør-Trøndelag District Court or a body appointed by this court.

This agreement is signed in 4 - four - copies, where each party to this agreement is to keep one copy. The agreement comes into effect when it has been approved and signed by NTNU represented by the Head of Department.

Note that the Norwegian version of this standard agreement is the authoritative version.

18.01.2021	Maria Assumpta Nakibuule

Digitally approved, date (dd.mm.yy) student

19.01.2021	Carl Fredrik Berg

Digitally approved, date (dd.mm.yy) supervisor at NTNU

26.01.2021	Turid Oline Uvsløkk

Digitally approved, date (dd.mm.yy) Head of Department, NTNU

26.01.2021	Trygve Randen

place, date (dd.mm.yy) for company/organization signed and stamped

Norwegian University of
Science and Technology