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Evaluation of Fishbone Lateral Stimulation

A Simulation Study

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Dedication

This thesis is dedicated to mom and dad, and my beloved fiance.

Summary

Fishbone stimulation was simulated using ECLIPSE 100 in autumn semester project, 2013. I used LGR (Local Grid Refinement) Options in ECLIPSE to emulate fishbone needles extending to reservoir for a single vertical well. It was concluded that fishbone stimulation could increase well productivity, reduce skin factor, and reduce potential water or gas coning. ECLIPSE simulation requires some simplification, as the nature of the software itself does not enable for flexible grid shape and size, two important requirements needed for near well bore simulation.

BRILLIANT is designed to deal with several physical models calculated simultaneously in the fluid flow from reservoir to well bore. It utilizes flexible grid size and shape and claims to calculate fluid flow equation accurately and effectively. Recently, BRILLIANT is furtherly developed to be compatible with porosity flow option in reservoir (Darcy flow) and update the calculation stability algorithm. Accurate simulation result is expected from BRILLIANT detail simulation for fishbone case.

The goal for this master thesis is to perform fishbone simulation using BRILLIANT and compare it with ECLIPSE simulation result. The case conducted in semester project will be simulated using the latest version of BRILLIANT. This comparison result determines direction of the research afterwards. In the case of insignificant difference of both simulation results, it would be confirmed that ECLIPSE could guarantee accurate result for well performance in fishbone stimulation case. In other words, it is unnecessary to simulate reservoir and near well bore details using BRILLIANT. However, different result between ECLIPSE and BRILLIANT simulation would divulge a good recommendation to use BRILLIANT simulation result as an input to ECLIPSE simulation.

Result of this research is as follows. BRILLIANT and ECLIPSE simulation gives a different result for fishbone simulation case, thus it is required to upscale BRILLIANT as an input to correct ECLIPSE fishbone simulation. The upscaling technique in ECLIPSE could be conducted by two methods: permeability or skin modification, in order to match BRILLIANT simulation result.

Furthermore, controllable and uncontrollable parameters are varied to quantify those effect to fishbone well performance. The parameters include fishbone needles number, fishbone annulus size, fishbone needle length, reservoir thickness, and reservoir heterogeneity. Fishbone stimulation is also compared with the existing conventional fracturing to analyze the most effective method for increasing well performance.

Preface

This thesis is submitted for partial fulfillment of the requirements for the master degree which is compulsory for all master student in the 4^{th} semester at Norwegian University of Science and Technology, NTNU. It covers 30 ECTS (one semester) work of TPG4920 Petroleum Engineering Master Thesis subject.

The work has been carried out during January 2014 to June 2014. By submitting this thesis, I expect to contribute for oil industry, specifically by evaluating fishbone performance using both reservoir simulation and near-well bore simulation.

I would like to thank to my supervisor, Professor Ole Torsæter, for the support during my project and thesis work. I would like to thank to Ying Guo (Total E&P Norge) for the topic and technical support from the summer project until master thesis. I would like to thank to Geir Berge (Petrell AS) and team for granting access to BRILLIANT software and all the facilities during my thesis writing. Special thanks to Silje Almeland (Petrell AS) for her guidance of BRILLIANT simulation and many enriching discussions together. Thanks to NTNU for providing a lot of useful papers, journals and softwares that aid my research work.

Last but not least, I would like also to thank to my family for bunch of loves and moral support. And thank you to my love, Daniel, for everything you have done.

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Abbreviations (SI)

q_o	=	oil flow rate
μ_o	=	oil viscosity
B_o	=	oil volume fraction
k	=	rock or matrix permeability
k_f	=	fracture permeability
k_v	=	vertical permeability
k_h	=	horizontal permeability
k_s	=	skin permeability
c_f	=	fluid compressibility
ρ	=	density
P	=	pressure
V_{ff}	=	fluid volume
V	=	total volume
A	=	total area
β_v	=	porosity in BRILLIANT
β_A	=	permeability in BRILLIANT
h	=	reservoir thickness
A_f	=	flowing area of fluid
r_e	=	external reservoir radius
r_w	=	well radius
r_{we}	=	equivalent well radius
r_s	=	skin radius
S	=	skin factor
σ	=	effective in-situ stress
S_z	=	overburden stress
P_p	=	pore pressure
P_R	=	reservoir pressure
P_{bh}	=	bottom-hole pressure
E	=	modulus Young
Δx	=	strain in x-direction
w_f	=	fracture width
α	=	Biot's constant
C	=	leak-off coefficient
F_{CD}	=	average conductivity
x_f	=	fracture length
nx, ny, nz	=	division in x, y, z direction
chPar	=	draw command in cylinder BRILLIANT
Gtl, Gtu	=	thickness of the cylinder wall at lower or upper level BRILLIANT
iRadl, iRadu	=	inner diameter of the cylinder at lower or upper level BRILLIANT
Le	=	length of cylinder BRILLIANT
Ang, AngEnd	=	rotation angle at the lower or upper end of cylinder BRILLIANT
chAx	=	axes where angle is rotated BRILLIANT

CHAPTER 1

Introduction

Conventional reservoir, which is marked by reasonably high porosity and high permeability, currently accounts for only a small part of petroleum remaining reserves. World high oil demand pushes the industry to look for various alternative petroleum sources. Oil recovery coming from unconventional resources or mature field is interesting in light of the current high oil price and changing tax regimes, in spite of money and advanced technology spent to extract them.

Well stimulation is a technique to increase well performance by increasing flow area and removing damage near well bore. Purpose of a stimulation job is to increase natural permeability and reduce skin factor. Fracturing fluid is pumped into reservoir in a specific pressure to create new fluid paths. Stimulation technology is favored in low quality reservoir or mature field because it lengthens and revitalizes a lot of wells in a relatively short period of time. Based on the fluid type used, fracturing is classified into hydraulic fracturing and acid fracturing.

Shale boom in USA for the last five years has driven stimulation technology far ahead. Shale oil or shale gas reservoir is considered uneconomical without utilizing horizontal wells and massive hydraulic fracturing. Well performance increases to be 10 times higher after a successful fracturing operation in many cases (Hager, 2008). On the other hand, hydraulic fracturing operation requires a lot of resources, as typical hydraulic fracturing for a horizontal well spends 3 to 5 million gallons of water per well (Arthur et al., 2008). Other concerns identified is the impact to groundwater in the shallow coal bed methane hydraulic fracturing (DrillingContractor, 2000). There is also a possibility that stimulation unwantedly reaches water-bearing zone, resulting in high water production. Fracture operation faces difficult challenges such as environmental risk, job complexity, and high operational cost.

Another method to increase well productivity is drilling a horizontal well. Horizontal well is well justified in thin bed formation with relatively high vertical permeability. However, utilization of multi-lateral well is avoided because of its cost and complexity.

Fishbone technology provides solution to effectively drain reservoir by drilling only one mother bore well. The unique stimulation technology is invented by Fishbone AS and called fishbone stimulation. The stimulation has a purpose to increase well performance in mainly carbonate reservoirs. Vertical or horizontal motherbore well is drilled and completed without casing (open hole completion). Liner of several subs consisting fishbone needle is run downhole through liner to create several multilateral tunnels perpendicular to the main well and penetrate several layers by jetting acid within fishbone needle and circulate back through fishbone annulus. Up to 300 jet laterals is possible to be installed in single fishbone completion job for less than one hour (FishbonesAS, 2012). Operational parameters, including needles length and width, influence well performance in fishbone stimulation. The advantages of fishbone compared to hydraulic fracturing are: less operating time, resources and money invested for the project. Freyer and Shaoul (2011) also stated that pressure drop in the fishbone fracture tunnel is negligible. Water and gas coning are avoided because sufficient needle height from water and gas zone is possible to determine. Fishbone technology illustration is showed in **Figure 1.1**.

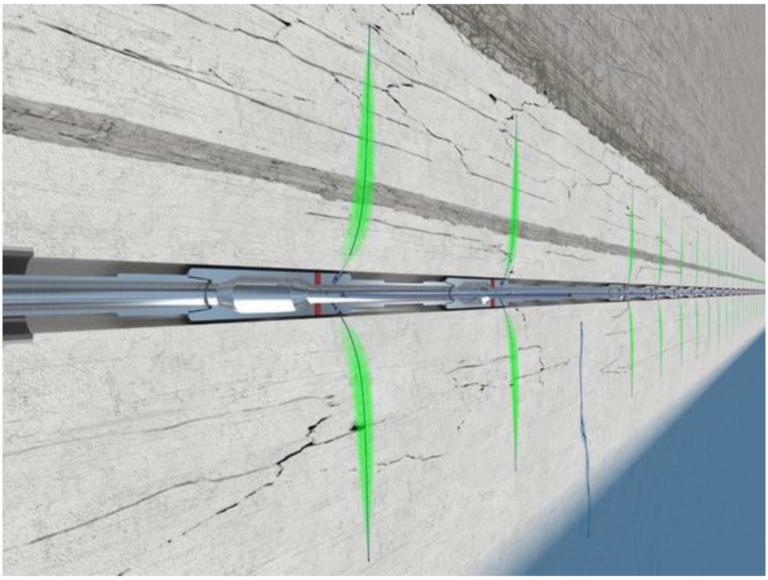

Figure 1.1: Fishbone Technology (FishbonesAS, 2012)

Fishbone simulation is reasonably easier to predict as fracture length is determined and assumed as infinite-fracture conductivity. Uncertainty in fishbone operation is subjected to operational condition, for example whether all needles from the liner will extend fully to the formation . This is crucial to the whole completion as fishbone is a permanent completion, although the remaining needle inside the liner could be milled (FishbonesAS, 2012).

Fracture simulation is important to optimize the fracturing and completion design, as well to validate analytical model before man execute the fracture operation. Simulation is also used to assess whether the project to be conducted is economically feasible or not. Suitable flow regime, fluid interaction and flow within fracture, and effect of fracture orientation to flow enhancement are mostly modeled by numerical simulation. Several research works have been done in simulating complex fracturing operation. Jayakumar et al. (2011) applied numerical simulator to study reservoir performance and history match production for tight gas and shale gas, while Cipolla et al. (2009) and Freeman et al. (2009) identify the most important mechanism affecting shale gas performance.

Fishbone was simulated using commercial reservoir simulation software ECLIPSE

100 in autumn semester project. Fishbone simulation is reasonably difficult to simulate in ECLIPSE due to geometrical discrepancy and fluid flow complexity in the reservoir and near well bore area. One grid block of the typical reservoir simulation has a dimension of several hundred meters while one fishbone needle length is only in the range of 10-12 meters. Detail fluid flow conduit from the annulus of fishbone into small hole in the liner completion which is called port is also impossible to generate in ECLIPSE grid. Such detail flows need smaller grid scale dimension and several flow models.

More accurate simulation result is expected from BRILLIANT for fishbone simulation case. BRILLIANT software is designed to deal with several physical models involved simultaneously in the fluid flow from reservoir to well bore. BRILLIANT uses flexible grids system to enable doing more accurate approach to complex geometry case. Recently, BRILLIANT is furtherly developed to be compatible with porosity flow option in reservoir (Darcy flow) and updated with more stable calculation algorithm.

The goal for this master thesis is to perform fishbone simulation using BRILLIANT and compare it with ECLIPSE simulation result. The case conducted for semester project will be simulated using the latest version of BRILLIANT. Moreover, controllable and uncontrollable parameters are varied to quantify the effect to fishbone well performance. The parameters include fishbone needles number, fishbone annulus size, fishbone needles length, reservoir thickness, and reservoir heterogeneity. Fishbone stimulation is also compared with conventional fracturing to analyze the most effective method for increasing well performance.

CHAPTER 2

Well Stimulation Technology

Permeability and skin factor are two crucial things in stimulation treatment. Skin permeability is exacerbated by well damage and mud filtrate invasion. Purpose of a stimulation is to clean-up damage and enhance permeability near well bore, as fracture creates conductive flow network. Fracture quality is corresponded to fracture length and conductivity. Fracture length determines penetration depth and fracture conductivity is a product of fracture permeability and fracture width. Conductivity is often approached by cubic law, in which conductivity is only a function of aperture (fracture width). Cubic law is valid under the assumption of infinite conductivity fracture and it is showed below.

$$w_f k_f = \frac{w_f^3}{12} \tag{2.1}$$

with w_f is fracture width and k_f is fracture permeability.

Successful stimulation operation relies on rock geomechanics and type of stimulation fluid. Due to the data importance, it is common to do a mini-frac before fracture operation to calibrate and obtain geomechanics data, such as in-situ stress, fracture geometry, leak-off coefficient, stress closure, and fracturing fluid efficiency (Economides et al., 2000). Young modulus plays an important role in creating fracture conductivity, as stronger rock (high Young modulus) is more difficult to fracture. There are many types for stimulation fluids, such as gelled hydrocarbons, linear and cross-linked water base fluids, foams, and emulsions. Criteria for fracturing fluid is having high viscosity to avoid leak-off and as a result creating long fracture. However, viscosity should not be to high to create moderate friction losses.

2.1 Reservoir Geomechanics Consideration

There are three principal in-situ stresses in reservoir: vertical (overburden stress), minimum horizontal stress, and maximum horizontal stress. Fracture direction is subject to direction of the stresses. Regardless of the fracturing fluid used, fracture is formed in direction perpendicular to minimum in-situ stress. Fracture direction is showed in **Figure 2.1**.

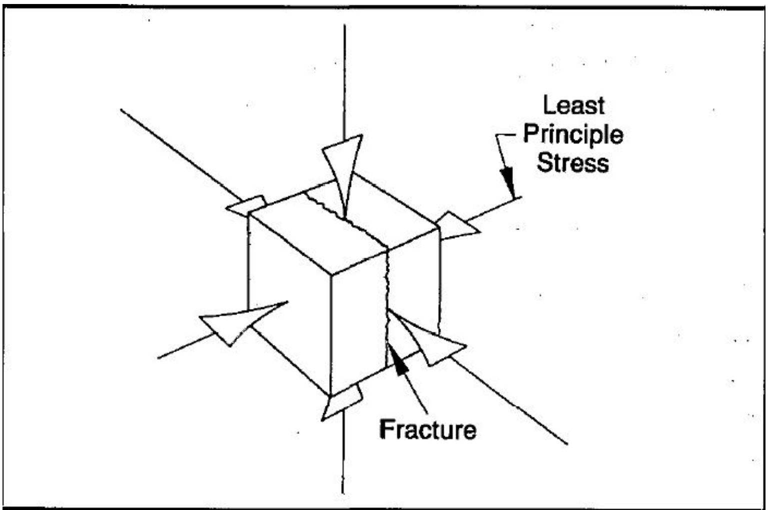

Figure 2.1: Fracture Direction (Economides et al., 2000)

Vertical fracture is created in normal fault area or deep reservoir (more than 900 ft), while horizontal fracture is created in high compression stress area or shallow reservoir. Vertical fracture could be perceived as the presence of horizontal well, as both have similar flow regime sequence: radial vertical, linear, and radial horizontal. Horizontal well behaves as a long infinite conductivity fracture that is very effective for a thin reservoir with relatively high vertical permeability.

Effective in-situ stress is a function of three principal stresses and fluid pressure, defined as,

$$\sigma = S_z - \alpha P_p \tag{2.2}$$

with σ is effective in-situ stess, α is Biot's constant, S_z is overburden stress, and P_p is pore pressure. Biot's constant, α value is between 0-1. Fracture is initiated when rupture pressure is achieved. Rupture pressure is strongly related with well geometry, pre-regional stress, and stimulation fluid used. Fracture continues to propagate further under subjected pressure.

2.2 Classification of Well Stimulation

Stimulation technique is classified into matrix and fracturing treatment based on pressure subjected. Matrix treatment is a type of stimulation operated lower than reservoir fluid pressure. The purposed is to clean damaged zone and restore natural reservoir permeability. Acid is used as stimulation fluid, as it reacts well with reservoir rock material. Fracturing is a type of stimulation operated higher than reservoir fluid pressure. Pearson (2001) defined that fracturing job is considered successful if equivalent well bore radius after fracturing operation equal with half of fracture half length.

Fracturing is furtherly classified into hydraulic fracturing and acid fracturing based on type of stimulation fluid used. Reactive lithologies like carbonate and chalk are more effective to be treated with acid fracturing, while a low permeability reservoir is a good candidate for hydraulic fracturing. However, reactive formation with minimum stress more than 5000 psia or unconsolidated formation prefers hydraulic fracturing, as the formations will not retain integrity after job completion without being held by proppant (Hager, 2008). Hydraulic fracturing has advantages for its long and stable fracture, however proppant is likely to produce and this condition will reduce permeability within fracture. Acid fracture is assumed as infinite conductivity fracture, as it creates highly conductive fracture network, while proppant treatment gives limited conductivity value due to sand production and proppant crushing.

Nierode and Kruk (1973) showed that the fracture conductivity can be predicted from the closure stress, rock embedment stress, and dissolvent rock equivalent conductivity. A typical stimulation had 400-500 feet of 4 spf perforation, and up to 10 stages of fracturing and 100 barrels of 15% acid pad were used per stage (Snow and Hough, 1988). More number of stages are required for fracturing long horizontal well and it is likely to have high concentration only in toe or heel section of the horizontal well.

2.3 Hydraulic Fracturing

Hydraulic fracturing is widely used for intensive stimulation of oil and gas, especially in extremely low permeability formation, as it is designed to create effective fracture network. It is implemented massively for shale gas completion in horizontal well. One hydraulic fracturing job includes up to 37 stages of fracturing in horizontal wells (Darishchev et al., 2013). A lot of water resource is required for hydraulic fracturing. Typical hydraulic fracturing job in USA requires 3-5 million gallons of water per well (Arthur et al., 2008). Hydraulic fracture well is showed in **Figure 2.2**.

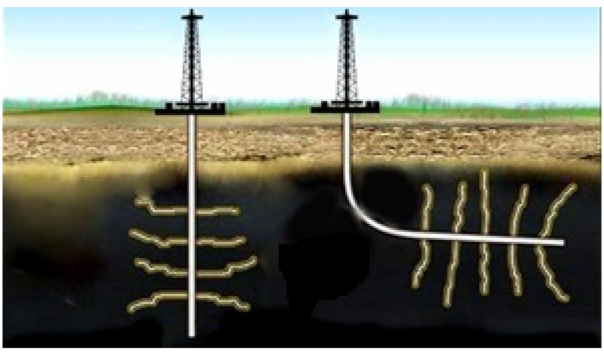

Figure 2.2: Hydraulic Fracture Well (DTH, 2010)

Fracturing fluid is utilized to open and extend fracture hydraulically and transport proppant along fractures. Fracturing fluid leaks-off to formation and pressure within fracture falls after operation finishes. Thus, proppant is co-injected to keep the fracture open. Common fracturing fluid used for hydraulic fracturing is water base polymer. Fracturing fluid criteria for successful fracture operation are: low fluid loss, good temperature and shear stability, minimum damaging effect for permeability, low pipe friction loss, and low cost. Criteria for good proppant quality are: high strength and stability, good size and shape distribution. Proppant embedment of 1/4 to 1/3 of a grain is expected on each fracture face (Snow and Hough, 1988).

To restrain proppant flow within fracture, screen-out method is introduced. Screen-out creates larger pressure within fractures, thus widens the fractures. Diversion technique is done to ensure fracturing fluid uniform distribution across the whole interval. Injected fluid flows through less resistance (high permeability) path, creating a viscous fingering which ineffectively drains formation, bypasses area with low permeability. Diversion method is classified into mechanical (ball sealers, packers, straddle-packer) and chemical (nitrogen foam, bridging agent, and cross-linked polymer) methods. Mechanical diverters are not very effective for long horizontal well, while chemical diverters give risks of permanent plugging (Davies and Kelkar, 2007). Efficiency in propped fracture incorporates determination effective volume of fluid and proppant to achieve fracture length with constant proppant concentration.

2.4 Acid Fracturing

Acid fracturing is favorable for a highly reactive reservoir, such as carbonate and chalk. Hydrochloric acid (HCl) is commonly used as a fracturing fluid in acid fracturing. Acid flows along the fracture by means of diffusion and convection and reacts with reservoir rock. The reaction leads to dissolution and produces non-uniform etching surfaces. The asperities act as conductive flow path and wormholes in the reservoir after fracture operation finishes (fracture closes). The etching surfaces close further as reservoir pressure depletes and in-situ stress increases. Stress-affected conductivity value is determined by rock mechanical properties. Type curves can provide drawdown pressure envelope for calculating conductivity upon stress by using iteration or numerical simulation. In many acid fracturing cases, well performance increases 10 times higher after a successful operation, however it gets back to original value after a few months (Hager, 2008).

There are several factors influencing acid fracture conductivity, namely: leak-off coefficient, viscous fingering, rock mechanical properties, injection rate, acid concentration, formation heterogeneities, and acid contact time (Gong et al., 1999). Acid leak-off could be prevented by conducting multiple-stages fracture and increasing fracturing fluid viscosity, suggested viscosity contrast is 200-300 (Davies and Kelkar, 2007). High injection rate increases acid penetration by limiting leak-off and creating higher pressure (Snow and Hough, 1988). High acid concentration will also improve penetration, while gelled acid holds fracture width longer. Typical acid concentration suggested for Ekofisk field is 28% (Snow and Hough, 1988).

Long contact time between acid and rock increases channel conductivity and limits amount of fingering. However, too long acid contact time may not be beneficial because it can weaken fracture surface (Economides et al., 2000). The effect of weakening is bigger near well bore because it is the place where acid contact is the most. Rock mineralogy effects acid/rock reaction rate, for example calcite reacts faster with acid compared to dolomite. Fissured formation, characteristics of carbonate reservoir leads to unwanted fracture orientation, thus reducing effective fracture length. Permeability distribution also plays an important role on acid fracturing, as high horizontal permeability correlation results in long lasting conductive fracture.

Higher temperature is favorable for acid/rock reaction, as fracture penetration depends on effective diffusivity which strongly varies with temperature. For a weak formation, mixture of proppant and acid is pumped. However, a formation with natural fractures is not suitable for proppant/acid fracture, as proppant could clog up or damage natural fractures.

Homogeneous etched surface fracture tunnel is vulnerable to close in high in-situ stress environment. Uneven etched-fracture is encouraged by presence of natural fracture and well bore inclination, and suitable amount of fingering. Fingering is initiated by near perforation effects and uneven fracture face and to some extent, fingering is effective to increase conductivity and encourage heterogeneous etched fracture (Hartley and Bosma, 1985). Perforation prior to acid stimulation is suggested to generate limited fingering effect. By doing this, acid pumped after flows easily within fracture finger and creates more wormhole networks and heterogeneous etched fracture pattern.

Acid may cause casing collapse problem and large cavity near well bore area

(Patillo and Smith, 1982). Maximize acid flow rate near well bore area helps to prevent the issue. Application of solid acid is claimed to overcome well integrity issue and reduce leak-off (Davies and Kelkar, 2007).

2.5 Kiel Fracturing (Kiel, 1976)

Kiel fracturing is a method of fracturing without using proppant or acid. The process was invented by Othar M. Kiel in the early 1970s. Thin water base fluid is injected into the formation then well is allowed to flow back in the fracturing operation. The cycle is repeated several times until some of rock material is broke-off and eroded, creates a void tunnel inside the formation.

2.6 Fishbone Lateral Stimulation

Fishbone well is one type of an innovative completion, utilizing one mother bore well that consists of several small and short lateral wells. Fishbone stimulation creates more uniform drainage pattern in the reservoir because of the lateral placement of the jets. Well productivity can increase 20-30% with the multilateral jet with 12 meters lateral extension, and have the equivalent rates as 3 propped fractures (Freyer et al., 2009). Fishbone also ensures well-distributed acid in high-extended horizontal wells and reduces acid leak-off rate. Fishbone stimulation illustration is showed in **Figure 2.3**.

In a thick, multilayered reservoir, nor one vertical neither one horizontal well is enough to drain the whole oil in the reservoir. However, utilization of multi-lateral well is avoided because of its high cost and complexity. Fishbone provides solution to effectively drain reservoir by drilling only one motherbore well. Fishbone technology is suitable for the following reservoir: low permeability reservoir, compartmentalized, faulted, naturally fractured, reservoir without sufficient depth accuracy for sweet spot well placement, and reservoir with low vertical permeability.

Fishbone stimulation utilizes a permanent liner completion consisting of several subs. Each sub consists of four jet laterals that ejects through the formation near well bore regions (Freyer and Shaoul, 2011). For chalk reservoir, fishbone uses acid (5-28%

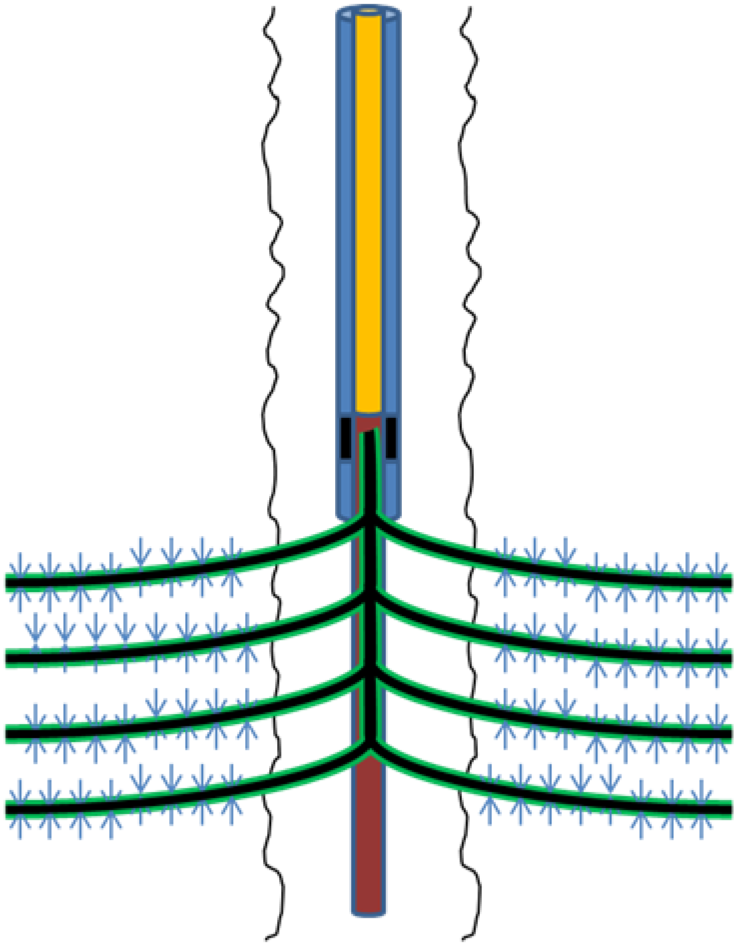

Figure 2.3: Fishbone Stimulation

HCl) as a fracturing fluid because it easily reacts with the reservoir rocks and creates conductive flow path. The operation starts by pressuring up the liner greater than reservoir fluid pressure. Pressure differential (jetting pressure) across the liner pushes the needles into the formation. Jetting pressure is related to selected nozzle design, and it is not driven by rock fracturing pressure or other geomechanical properties. As the needle extended, the acid flows inside the needle jets through nozzle in the end of the fishbone needle. The acid then circulates back to the surface by passing through the fishbone annulus, reacting with the reservoir rock, creating the etching surface in the reservoir, and bringing along rock cuttings. This mechanism is analogous with drilling principle, using acid as drilling fluid. The etching fractures create conductive flow path along fishbone annulus. After all needles extracted fully, the job is considered finished. The needles could be kept permanently or chemically removed (Freyer and Shaoul, 2011).

As a fracture operation finishes and production starts, minimum horizontal stress will increase to give excessive load to fracture opening and gradually close the fracture (Hager, 2008). Fracture width closure depends on several factors related with reservoir geomechanics properties, such as in-situ stress, reservoir tensile and compressive strength. Elastic response to open fracture follows Hooke′s law of elasticity and is controlled by Young modulus of the formation, as the equation below,

$$\sigma = E\Delta x \tag{2.3}$$

with σ is stress, E is Young Modulus, and Δx is strain in x direction. While in-situ stress increases, as a function of reservoir pressure depletion, the rock will gradually go to plastic region. In the plastic region, pore collapses and deforms. Rock compressive failure will reduce fracture width and generate fine rock particles that aggravated fracture conductivity further. It leads to permanent fracture conductivity reduction. In water breakthrough, condition is aggravated further as plastic chalk formation shall not maintain integrity (Freyer and Shaoul, 2011). Acid and rock etched fracture surface is suspected homogeneous in fishbone stimulation, as predicted from etching mechanism, thus it is concerned whether the fractures will retain high conductivity subjected to high in-situ stress after fracture operation finishes.

2.7 Stimulation Design for Chalk Reservoir

North Sea chalk reservoir in Ekofisk area is a good reservoir to be treated with fracturing, as it has a very high porosity (30-50%) and variation of matrix and fracture natural permeability (Snow and Hough, 1988). The reservoir has heterogeneous vertical and horizontal layers and has strong variations for porosity, permeability, strength, and in-situ stress distribution. However, the chalk is reported too soft to retain conductivity after stimulation due to low geomechanical strength and it is further softened by water production. Pore collapses as effective stress increases and this is the main phenomena accounts for Ekofisk subsidence.

Stimulation treatment is a custom operation. Not all type of stimulations are suitable to be applied to the reservoir. Hydraulic fracture is suitable for a non-reactive or low permeability reservoir, while acid fracture is suitable for reactive reservoir with sufficient strength, and matrix treatment is suitable for a reservoir with high natural permeability. High angle hydraulic fracturing is strongly proposed for low permeability thick bed reservoir. Under special consideration, hydraulic and acid treatment could be conjugated to achieve optimum result. Apart from that, there are several parameters accounted for successful stimulations.

- Chalk Hardness

  Measurement for chalk hardness is Brinell Hardness Number (BHN). BHN increases with increasing silica content, depth, and porosity. Slower depositional environment leads to harder and more cementation. Plastic failure and massive chalk flow are observed for rapid drawdown.

- Rock Mechanical Properties

  Elastic and plastic behavior are pressure and time dependent. Rock behaves as a linear elastic material at low stress condition, while it goes to plastic region at high stress condition (Johnson and Rhett, 1986). There are several methods to measure rock mechanical properties: micro-frac, anelastic strain recovery (ASR), differential strain curve analysis (DSCA), differential wave velocity analysis (DWVA), and log measurement (Snow and Hough, 1988). ASR measurement shows minimum in-situ stress and there is a large stress increase at shale/chalk interface. There are two factors affecting in-situ stress orientation: local and regional tectonic condition and reservoir compaction.

- Natural Fracturing

  Natural fracture is a conductive fluid area near well bore, usually varies from a few inches to several feets. It also enhances acid stimulation, as acid flows inside fracture and creates further wormhole. Natural fractures are influenced by in-situ stress and perpendicular to direction of minimum in-situ stress (Snow and Hough, 1988).

- Leak-off Coefficient

  Leak-off coefficient is high in a high natural fracture area, large capillary force, and quick acid/chalk reaction rate. In acid fracturing, reasonably amount of leak-off is necessary to improve productivity by etching natural fractures. Leak-off is prevented by shortening reaction rate and using higher fluid viscosity. Leak-off coefficient is usually measured by mini-frac operation prior to fracturing. Following leak-off coefficient value are used when leak-off coefficients are not obtained in hydraulic fracturing:

$$C = 0.0005ABD \tag{2.4}$$

  A = 1.0 for low fracturing, 2.0 for moderate fracturing, 3.0 for highly fractured

  B = 1.0 for oil wet, 2.0 for water wet

  C = 1.0 for low permeability oil, 1.5 for low permeability gas, intermediate permeability oil, 1.5 for low permeability oil, intermediate permeability gas, 2.5 for high permeability gas

- Induced Fracture Growth and Stability

  Induced fracture orientation is parallel to natural fracture direction. Growth of induced fracture is generally vertical and radial. Deviation of the growth is caused by: deviated well, presence of natural fracture, and lithostatic condition (Snow and Hough, 1988).

Decline in fracture conductivity is strongly associated to rock failure. Failure is caused by: chalk plastic flow, creep flow and pore collapse, chalk crushed, brittle failure, clogging fines, and slippage along fracture phase. Pore collapse, caused by increasing in-situ stress, is perceived as the main cause of fracture closing and it is time dependent as reservoir produces and pressure depletes. To lengthen well life, production is not done in maximum drawdown mode. Laboratory experiment showed that losses in conductivity are time dependent, taking up to 1000 hours (Snow and Hough, 1988).

2.8 Data Requirement for Fracture Design

Prior to fracture operation, extensive studies are carried out to investigate geomechanics data for targeted formation. These data are required to model formation mechanics properties and their responses to fracturing. The data consist of Young Modulus, Poisson Ratio, fracture toughness, in-situ stress distribution, tensile strength, and compressive strength.

Sources for geomechanics data are: laboratory test, downhole logging tools, and mini-frac test. Laboratory test usually takes a lot of time and resource. However, the result does not always represent real formation data, especially in heterogeneous reservoir. Reservoir parameters, for example pressure and temperature should be accounted for the result because measurement is conducted in laboratory condition.

In-situ stress distribution and Young Modulus are obtained from acoustic log data or mini-frac test. Fracture toughness, tensile, and compressive strength is obtained from extensive geomechanics laboratory test (Economides et al., 2000). Several down hole tools are applied to support fracture design, including Thermal Decay Time (TDT) spinner logs, temperature survey, and Repeat Formation Tester (RFT). TDT log is used to determine flow contribution from each interval and determine acid near well bore placement, temperature data is used to determine fracture height, and RFT is used to determine differential pressure depletion.

2.9 Fracture Geometry Modeling

Fracture dimension plays an important role in determining conductivity and penetration depth. Prior to model fracture geometry, geomechanics data requirement should be fulfilled. Unknown parameters willing to be solved by fracture geometry modeling is: fracture height, fracture length, and fracture width. Fracture geometry modeling technology is initiated by development of 2D model (KGD and PKN), pseudo 3D model, MLF model, and 3D model. In 2D fracture, fracture height is specified. Fracture height data obtained from post-fracture analysis in previous treated well or log data. 2D fracture model is showed in **Figure 2.4**.

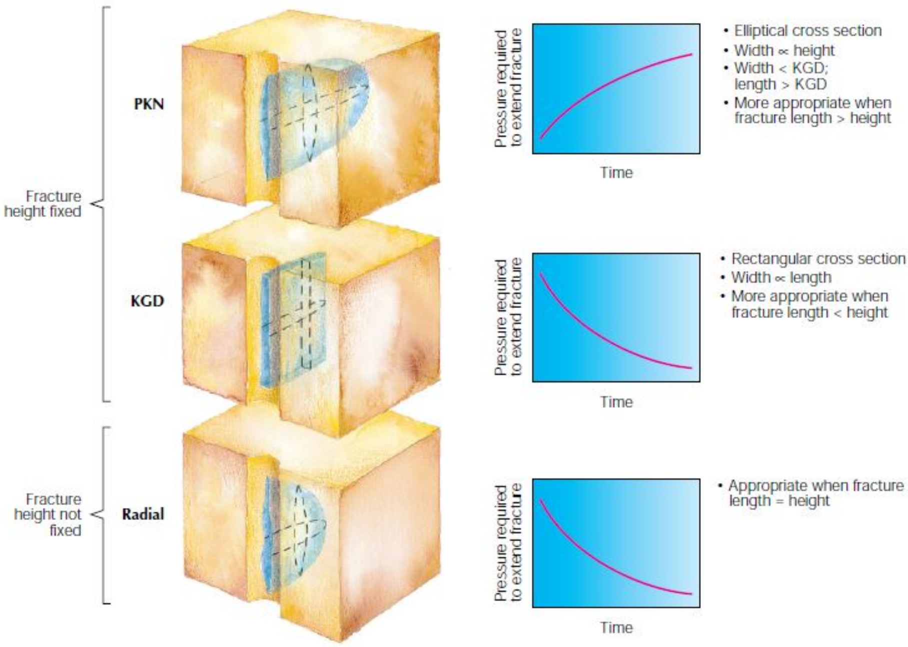

Figure 2.4: 2D Fracture Model (Schlumberger, 1992)

2.9.1 Fracture 2D Modeling

There are three well-known model approaches in 2D fracture geometry: KGD (Khristianovic -Greetsma-de Klerk), PKN (Perkins-Kern-Nordgren), and radial model. All fractures model use Sneddons equation as a basis of calculation. KGD and PKN model is used in high vertical stress contrast between layers, while radial model is used if stress contrast between layers is low. In radial model, fracture height value is not fixed as it is assumed that fracture length equals to fracture height. Difference between KGN and PKN model is the assumption of plane strains. KGD model assumes plane strain condition in horizontal planes, while PKN model assumes plane strain condition in vertical planes.

KGD approximately represents fracture with a horizontal penetration much smaller than vertical one. The fracture shape should depend on the horizontal position. It has a constant height and rectangular cross section. It is suitable for a shallow penetration fracture (fracture length less than height). PKN approximately represent fracture with a horizontal penetration much bigger than vertical one. The fracture shape should depend on the vertical position. It has a constant height and elliptical cross section. It is suitable for a deep penetration fracture (fracture length more than height).

To solve the coupled problem of elasticity and fracture fluid flow, an iterative process normally is required in both KGD and PKN models,

1. Assuming a pressure distribution in the fracture,

2. Determine the fracture width,

3. Given a width distribution, compute the pressure from fluid-flow equations,

4. Compare the assumed and computed pressures, and if they differ, iterate.

2.9.2 Finite and Infinite Conductivity Assumption

Infinite conductivity fracture is a fracture in which pressure drop along it is negligible. Acid fracturing is often assumed as infinite conductivity fracture, while hydraulic fracture conductivity is compromised by amount of proppant embedment, amount of damage from gel residue, proppant degradation, fines plugging, proppant back flow, inertial force, and multiphase flow (Pearson, 2001). Fracture conductivity value is often overestimated because value of effective permeability data is compromised. Cinco-Ley et al. (1978) demonstrated that the assumption of infinite fracture conductivity is valid whenever the dimensionless fracture conductivity$>$300; all other cases, such as those represented by long or poorly conductive fractures, must be analyzed by considering a finite-conductivity fracture model. Thus, fracture effective permeability and width should be calculated rigorously using collaborative laboratory data and field experience.

Fracture conductivity change related to in-situ stress is quantified using poroelastic model (Ben-Naceur and Economides, 1988) and is obtained using laboratory data (Novotny, 1977). Conductivity profile decreases along the fracture length, with a very high conductivity near well bore and lower conductivity as it goes deeper into reservoir due to varying acid concentration. Emulsion acid should be modeled with finite conductivity fracture as it has a lower concentration comparing to conventional acid treatment, although it reduces leak-off and lengthens fracture (Novotny, 1977). Actual fracture conductivity under stress is obtained using laboratory data, where acid reaction is determined from the effective diffusion coefficient from laboratory data and analogous heat transfer solution. Bennett (1982) modeled variation of fracture conductivity as a system with average conductivity, defined as,

$$F_{CD} = \frac{1}{x_f} \int_0^{x_f} \frac{k_f w_f}{k x_f} dx \tag{2.5}$$

with F_{CD} is average conductivity, w_f is fracture width, x_f is fracture length, and k is matrix permeability.

2.10 Analytical and Numerical Approach in Fracturing

Natural or hydraulic fracture flow modeling has been approached by various analytical and semi-analytical solutions. Reasonably accurate analytical simulation was developed by Blasingame and Poe Jr (1993). Medeiros et al. (2006) developed analytical models for multiple fracture horizontal wells. Most of complex fracture modelings has a purpose to simulate hydraulic fracturing in shale oil or gas reservoir.

Analytical model, despite of the high speed calculation, can not accurately handle the highly non-linear aspects of shale gas reservoir, because it addresses the non-linearity in gas viscosity and compressibility with the use pseudopressure rather than solves real gas flow equation (Olorode et al., 2013). Long transient flow is not always be captured by analytical solutions (Darishchev et al., 2013). Other limitations include the difficulties in accurately capturing gas desorption from the matrix, multiphase flow, multidimensional heterogeneities, pressure dependent permeability, and several non-ideal and complex fracture networks (Medeiros et al., 2006).

Several limitations in analytical solution lead to development of numerical simulation in fracturing. Olorode et al. (2013) represented multiple fractures with equivalent single fracture and doing simpler simulation. Interaction between primary and secondary fracture and fracture orientation has effects on flow behavior (Olorode et al., 2013). In a low permeability reservoir, transient flow regime is present for a long time. Transient flow behavior in such reservoirs is likely not captured after some time and should be treated discretely. Transient flow appearance and well bore storage effect should limit maximum grid block size in fracture simulation (Darishchev et al., 2013). Cartesian grid model is not always practical in complex geometry simulation. Curvilinear flow, for example, requires a large number of Cartesian grid cells to change orientation and shape of the grids. In such cases, Olorode et al. (2013) proposed usage of Voronoi grid model.

Acid fracturing is a complex reaction process and hard to be predicted easily. Leak-off and formation strength effect complicate the problem further. Statistics together with a lot of experimental works are often used to predict fracture conductivity under closure stress. Extensive studies and simulations are done to model acid fracture conductivity. Nierode and Kruk (1973) proposed empirical correlation for evaluating acid fracture conductivity based on experimental data.

Simulation works are also done recently for the same purpose. Deng et al. (2011, 2012) proposed a new correlation of acid fracture conductivity in intermediate scale under closure stress based on various numerical simulations. Gong et al. (1999) introduced fracture deformation model which considers surface roughness and rock mechanical properties. It is common to ignore non-Darcy (inertia) flow effect in fracture simulation, as it appears to have second order effect in high or infinite-fracture conductivity (Olorode et al., 2013). Ben-Naceur and Economides (1988) coupled acid concentration equation and fracture propagation equation to describe acid penetration.

There are several assumptions for acid fracturing model used today. First is diffusion limited kinetics. For limestone and dolomites at high temperature, acid wall concentration is assumed zero and effective diffusion coefficient is used. Second is reaction rate control. For emulsion and foam acid, acid concentration is not zero.

Fishbone simulation was done in last semester project using ECLIPSE 100 using simplified assumption. Local grid refinement (LGR) option is activated in ECLIPSE to compensate different magnitude of grid block size between reservoir and well (including fishbone). ECLIPSE is capable in doing full field reservoir simulation in longer time and it also has a very robust reservoir model to capture a lot of reservoir characteristics, such as reservoir heterogenities and fault models. However, ECLIPSE simplifies small physical phenomena in fluid flow. Therefore, parameters that should be taken into account could be neglected inevitably. Limitations in ECLIPSE simulation is expected to be addressed by BRILLIANT.

CHAPTER 3

Basic Well Performance

3.1 Productivity Index

Well productivity is a measurement of produced flow rate for the same drawdown condition. Productivity of the well is very important in analyzing well and reservoir properties and in predicting production. In a porous reservoir and single phase fluid flow, well flow rate is calculated by Darcy flow equation,

$$q_o = \frac{2\pi hk}{\mu oBo(ln(r_e/r_w) + S)}(P_R - P_{bh}) \tag{3.1}$$

with q_o is oil flow rate, h is reservoir thickness, k is reservoir permeability, μ_o is oil viscosity, B_o is oil volume fraction, r_e is external reservoir radius, r_w is well radius, S is skin factor, P_R is reservoir pressure, and P_{bh} is bottom-hole pressure. Well productivity is quantified with productivity index. For steady-state and pseudo steady-state flow, productivity index of the well is calculated with the formula below,

$$PI = \frac{q_o}{(P_R - P_{bh})} = \frac{2\pi hk}{\mu oBo(ln(r_e/r_w) + S)} \tag{3.2}$$

All the parameters affect well productivity and can be modified to increase productivity of the well. Well productivity index could be increased by increasing permeability (matrix treatment), reducing skin factor (hydraulic and acid fracturing), reducing r_e (infill drilling), and decreasing μ (thermal project). For stimulation treatment, permeability and skin factor are two main things to be concerned.

3.2 Skin Factor

Skin factor is an imaginary thin layer around well bore area where permeability value alters from main reservoir. There are several factors that cause skin area, such as invasion of mud filtrate, partial penetration, perforation, and fractures. Invasion by mud filtrate causes damages near well bore area. Skin area is largely affected and has a very low permeability. Consequently, skin causes additional pressure drop near well bore. Pressure profile in well with damage is shown in **Figure 3.1**. P_e is pressure in external radius, P_w is well pressure without skin factor, P_{wa} is well pressure with skin factor, r_e is external reservoir radius, and r_w is well radius.

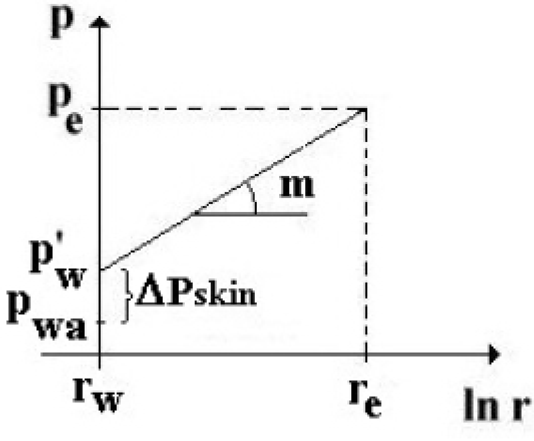

Figure 3.1: Pressure Profile for a Damaged Well (Jelmert, 2001)

Well with damage is observed from positive skin factor. On the other hand, perforation and fractures will create a lot of conductive flow path near well bore area. This is a favorable condition because the pressure drop will decrease. Well with natural fractures or after treatment has a negative skin factor. The main purpose for stimulation technique is to reduce the skin factor of the well to increase productivity by pumping stimulation fluid into reservoir at a certain pressure. Good fracture length and fracture conductivity are two criterias that become a purpose of fracturing job. Fracture length will determine how deep penetration into the reservoir, while fracture conductivity is a product of fracture permeability, k_F and fracture width, w_F.

3.2.1 Hawkin Skin Calculation

Hawkins (1956) introduced concept of skin as a thin layer that has an altered permeability from the rest of reservoir. Hawkin skin concept is showed in **Figure 3.2**. Equation used to calculate skin factor with Hawkins method is:

$$S = (\frac{k}{k_s} - 1) ln \frac{r_s}{r_w} \tag{3.3}$$

with S is skin factor, k is permeability, k_s is skin permeability, r_w is well radius, and r_s is

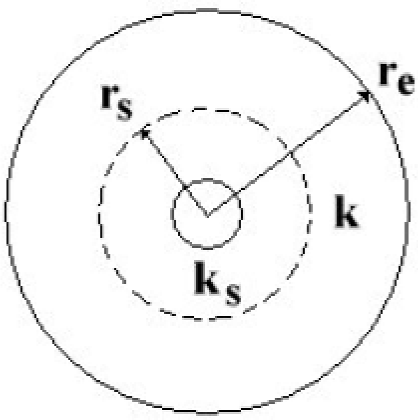

Figure 3.2: Two-Permeability Reservoir Model (Jelmert, 2001)

skin radius. Hawkins equation estimates maximum theoretical stimulation by,

$$S_{min} = -ln \frac{r_e}{r_w} \tag{3.4}$$

3.2.2 Equivalent Well bore Radius

Skin factor can also be calculated as the equivalent well bore radius of the calculated pressure. Damage leads to less equivalent radius while stimulation leads to larger equivalent radius. Equivalent well bore radius for infinite conductivity fracture is,

$$r_{we} = \frac{x_f}{2} \tag{3.5}$$

A rough estimate of the fracture half-length might be obtained from,

$$x_f = 2r_w e^{-S} \tag{3.6}$$

with r_{we} is equivalent well radius, x_f is fracture length, r_w is well radius, and S is skin factor.

3.3 Transient, Pseudo-Steady State (Boundary Dominated), and Steady-State Flow

Transient flow is an early time production of reservoir, and it assumes infinite-acting reservoir. Transient flow can be used for determining reservoir properties, such as permeability. During this period, the size of the reservoir has no effect on the well performance, and the reservoir size can not be determined except to deduce minimum contacted volume. Since the boundary of the reservoir has not been revealed during the transient flow period, static pressure at the boundary remains constant.

On the other hand, boundary flow is a late phase production in reservoir, it could be used to determine reservoir size or area. Pressure gradient over time is constant in pseudo steady-state flow (constant flow rate). Pressure gradient over time is not constant in boundary flow, as the flow rate is not constant (constant pressure). Steady-state flow occurs when outer boundary pressure is kept constant. Pressure gradient over time is zero in steady-state flow. Reservoir flow phases is showed in Figure **Figure 3.3**.

Low permeability reservoir will be in a transient flow phase in a very long time.

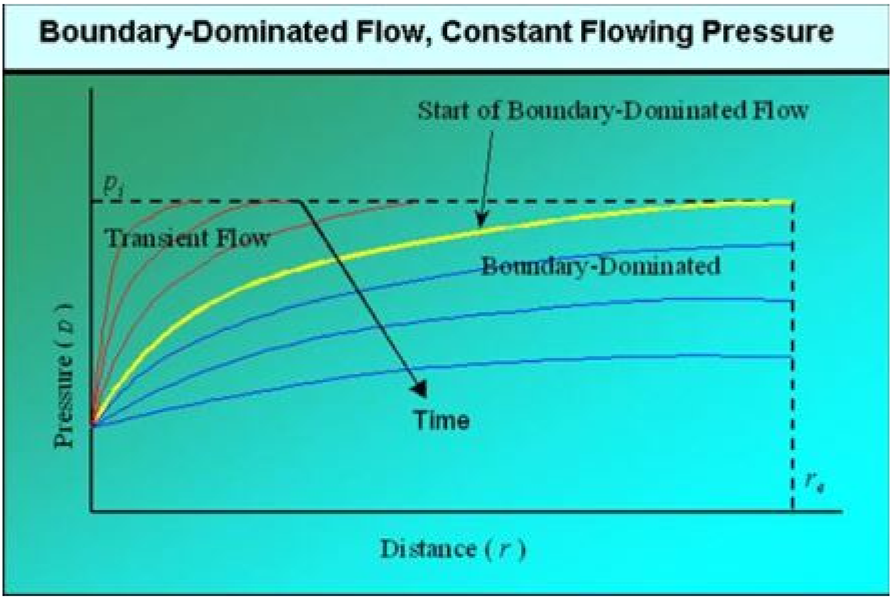

Figure 3.3: Reservoir Flow (Constant Pressure) (www.fekete.com, 2013)

Fracture flow (linear or bi-linear) regime could be observed in this phase. When it comes to simulation, too large grid block could mask this phenomenon and push pseudo-steady state flow too early.

CHAPTER 4

Simulation Comparison of Fishbone

4.1 BRILLIANT Software

BRILLIANT is a multiphysics simulation software developed by Petrell AS that can calculate and solve several physical models simultaneously. BRILLIANT uses flexible grids system to enable more accurate approach to complex geometry case. For fluid flow calculation, BRILLIANT uses the conservation principle of mass, momentum, and energy. Porosity flow in reservoir is based on Darcy equation. Porosity and permeability models are used to characterize a medium as a porous solid and partly blocked control volume. The porosity and permeability models in BRILLIANT are defined as below (Berge, 2011).

- Porosity Model

$$\beta_v = \frac{V_{ff}}{V} \tag{4.1}$$

- Permeability Model

$$\beta_A = \frac{\int\limits_{fluidsurface} \mathrm{d}A_f}{\Delta A} \tag{4.2}$$

with β_v is porosity, β_A is permeability, V_{ff} is fluid volume, V is total volume, A is total area, and A_f is flowing area of fluid. Advancement in BRILLIANT software allows more flexibility in grid shape. Grid shape flexibility makes fewer number of grids and enables more accurate calculation. However, BRILLIANT is still not capable in dealing multi-phase flow model and not able to capture heterogeneous properties in reservoir (such as porosity and permeability).

BRILLIANT uses several equations in solving the unknown variables: conservation of mass, conservation of momentum, and conservation of energy. Pressure is solved indirectly in each control volume. A common used algorithm is SIMPLE (Semi Implicit Method for Pressure Linked Equation) (Berge, 2011). This method uses continuity equation to establish pressure. Fluid properties in BRILLIANT, such as density and viscosity is calculated automatically based on thermodynamics fluid package in subjected to pressure and temperature. All units used in Brilliant are in SI system.

4.1.1 BRILLIANT File Structure (PetrellAS, 2012)

BRILLIANT simulation is built using five important files: admin, geometry, capture, model, and scenario file.

- Admin File

  Admin file contains file name, maximum time step, output frequence, courant number, and maximum time. Some important keywords for admin file is found in **Table 4.1**.

Table 4.1: Keywords Used in BRILLIANT Admin File

No.	Keywords	Description	Example
1	#MAX_TIMESTEP	Maximum time step used	#MAX_TIMESTEP dt1 time1 dt2 time2
2	#OUTPUT_FREQUENCE	Output frequence in result time	#OUTPUT_FREQUENCE dt1 time1 dt2 time2 ...
3	#COURANT_NUMBER	Maximum timestep allowed from grid calculation	#COURANT_NUMBER dt1 time1 dt2 time2 ...
4	#MAXTIME	Simulation time	#MAXTIME time

- Geometry File

In geometry file, user builds required tailored grid using various geometrical command. Keywords for geometrical command are explained in the next section. Boundary condition location is specified using keyword:
$**BOUNDARYCONDITIONS** [CV location].

4.1.1.1 Important Keywords in Geometry File

Some important keywords for geometry file is showed in **Table 4.2**.

Table 4.2: Keywords in Geometry File

No.	Keywords	Description
1	#CURRENT_MODEL_AREA	Assign geometry to a model
2	#SET_PART_NAME	Divide a model into several part geometry
3	#COPY [GroupName] and #PASTE [GroupName]	Repeat the same geometery in different location (can be also used symmetry)
4	#SPLIT_CV [nx ny nz]	Split CV inside defined area for further refinement
5	#EXTRACT [CV location]	Extract a volume from another volume and adjust the control volume. #EXTRACT command should be taken care carefully as it would not extract the exact volume if the host volume is extracted smaller than the smallest control volume. #EXTRACT command is only valid on coordinate (block) domain.
6	%ROTANG [angle]	Give angle of ratation of each axis
7	%ROTAX [axis]	Give axis point of rotation
8	%DISPLACE [vector]	Displace CV along the vector

- Capture File

Capture file is a facility allowing the user to capture results from given locations in dedicated files as the simulation is progressing.

- Model File

Model file is the input characteristics of the specified model. Model file determines assumption and calculation which needs to be solved in the model. User could also activate and deactivate model automatically in this file. There are five important models in BRILLIANT: porosity model (flow in porous media), dispersion model (flow in pipe), stress model, conduction model (thermal), and neutral model.

- Scenario File

  Properties of the grid is specified in scenario file. It includes initial condition (such as pressure, permeability, and porosity) and boundary condition (pressure, flow rate, velocity).

4.1.2 Control Volume (CV)

Control volume in BRILLIANT could be a rectangular or cylindrical shape. Cylindrical shape is more applicable for pipe or well, while rectangular (block) shape is more flexible to any shape.

4.1.2.1 Rectangular or Block CV

Block control volume shape in BRILLIANT is quite flexible. It does not need to be a rectangular shape. User only needs to assign coordinate of each nodes. Block building in BRILLIANT is used keyword #**BLOCK**. Block CV consists of 8 nodes, starting from node number 0, and in arbitrary block each node is pointed to certain location. In regular shape block, user only needs to define node 0 and node 6. All variable is considered in the geometric centre of each control volume.

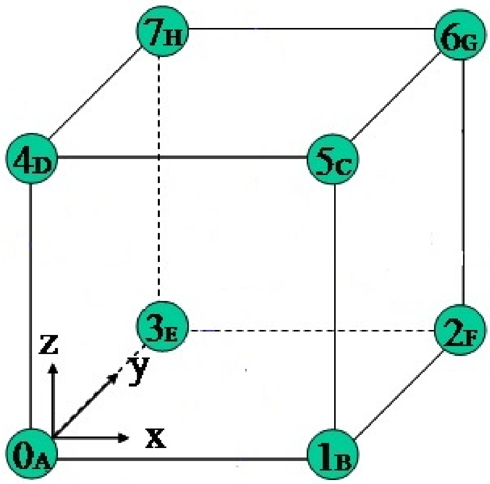

Figure 4.1: Numbering System in Block CV (PetrellAS, 2012)

Node 0 lies in the left bottom front corner of the block, followed by node 1 in the right bottom front. Node 2 and 3 follow counter-clockwise direction behind. Node 4, 5, 6, 7 follows the same structure as node 0, 1, 2, 3, unless they occupies top position. Block system in BRILLIANT is showed in **Figure 4.1**. Example for block code is given in **Table 4.3**.

4.1.2.2 Cylindrical CV

Cylinder CV is used for pipe and tank or other cylindrical shape. Cylinder command is given below:

#**CYLINDER** nx ny nz chPar

iRadl GTl Le Ang1 Ang2 chAx

iRadu GTu AngEnd1 AngEnd2 chAx

iRadu GTu Le AngEnd1 AngEnd2 chAx

...

chPar is a combination of the following letter. The letters could be single or written in any combination. Example for cylinder variation is given in **Figure 4.2**.

Table 4.3: Keywords Used in #BLOCK CV

No.	Commands	Description
1	#BLOCK nx ny nz 0 x0 y0 z0 6 x6 y6 z6	regular shape block
2	#BLOCK nx ny nz 0 x0 y0 z0 1 x1 y1 z1 2 x2 y2 z2 3 x3 y3 z3 4 x4 y4 z4 5 x5 y5 z5 6 x6 y6 z6 7 x7 y7 z7	arbitrary shape block

- I draw inside volume
- S draw shell volume
- O draw outside volume
- T draw top of volume

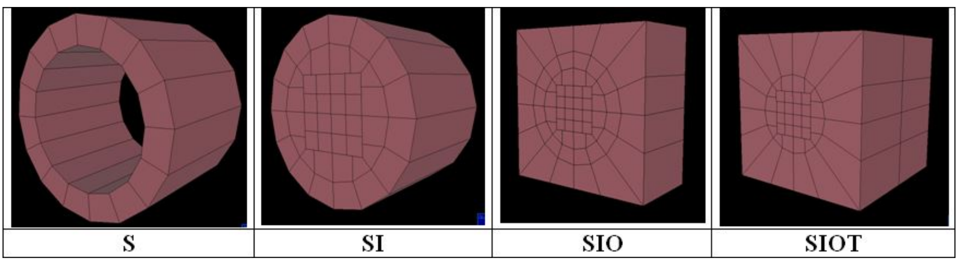

Figure 4.2: Cylinder CV Variation (PetrellAS, 2012)

Other important cylinder commands are showed in **Table 4.4**

4.1.3 Model Initialization and Boundary Condition

Several properties of the model such as pressure and temperature are needed to be initialized in simulation. Multiphase flow is still in development process. For fishbone simula-

Table 4.4: Keywords in Model Inactivation

No.	Keywords	Description
1	#CYLINDER_ANGLE [CV location]	Limit angle of cylinder.
2	#CYLINDER_CENTER	Number of control volumes along one side of the square in the centre of a circle.
3	#CYLINDER_SQUER_SIZE	Size of centre square relative to cylinder internal diameter, between 0 and 1.
4	#CYLINDER_PERPHERY	Number of CV around periphery. Minimum is 3.

tion, initial pressure, permeability, and porosity of the reservoir are defined in the boundary cells. Initialization of model is set using keyword #**INITIAL_CONDITIONS** in scenario file.

There are many types of boundary condition, such as fixed value, variable value, pressure, valve, etc. Location of the boundary condition is specified in geometry file. Boundary condition is set using keyword #**BOUNDARY_TYPE** [Name] [CV location].

4.1.4 Model Inactivation

There is an option to inactivate a desired model during simulation. Purpose of the inactivation is making the simulation runtime quicker. The inactivation could be cyclic or automatic. For the automatic mode, two tolerances as well as two reference points are needed in addition, while in cyclic mode inactivation is based on time. Tolerance for automatic model inactivation is based on pressure gradient change over time. Inactivation keywords are input in model file and showed in **Table 4.5** below.

Table 4.5: Keywords in Model Inactivation

No.	Keywords	Description
1	#REF_POINT_CURRENT_MODEL [CV location]	Reference point in model to be deactivated
2	#REF_POINT_OTHER_MODEL [CV location]	Reference point inother model (criteria to be reactivated)
3	#INACTIVE_CRITERIA	Maximum gradient pressure change over time to inactivate model in #REF_POINT_CURRENT_MODEL
4	#REACTIVATE_CRITERIA	Maximum gradient pressure change over time to reactivate model in #REF_POINT_OTHER_MODEL
5	#INACTIVE_PERIOD	Maximum time for model to be inactive
6	#INTEGRATION_PERIOD	Maximum time for model to be active

4.2 Comparison of BRILLIANT and ECLIPSE

As mentioned earlier, BRILLIANT and ECLIPSE has their own superiority and drawback in the fishbone simulation case. Comparison between those two software will help me to determine the advantages and disadvantages of each simulation and resulted in more accurate simulation.

In this section, I simulate fluid flow in a reservoir using BRILLIANT and ECLIPSE software for a simple geometry case. The purpose is to validate BRILLIANT simulation result using ECLIPSE, since I do not have production or laboratory data.

Case A.0 is simulated in order to validate BRILLIANT result with ECLIPSE. The case is very simple with one vertical well in the center of reservoir. Case A.0 description summary is showed in **Table 4.6**.

4.2.1 ECLIPSE Model Description for Case A.0

ECLIPSE simulation is equipped by activating Local Grid Refinement (LGR) options. LGR enables more grid numbers in the vicinity of well. Number of grid refinement near well bore was optimized during last semester project (Appendix C). Keywords for LGR options are summarized in **Table 4.7**.

Table 4.6: Case A.0 Description

No.	Parameter	Value
1	Reservoir Area	900x900 m^2
2	Thickness	20 m
3	P_R	380 bar
4	P_{bh}	330 bar
5	Fluid	Water
6	Porosity	40%
7	Permeability (k_x, k_y, k_z)	10 mD
8	Production Mode	Constant Pressure
9	Well Position	Center, Vertical
10	Number of Well	1 (Production)
11	Temperature	323 K
12	Initial Fluid Volume	6.48 Mm^3

Table 4.7: Keywords in LGR Options

No.	Keywords	Description
1	LGR	Describe the dimensions and switches required for the Local Grid Refinement and Coarsening options. Maximum LGR refinement and maximum cell in local grid is defined in the keyword.
2	CARFIN	Set up a Cartesian LGR. It specifies name, box of global grid block cells that needs to be refined, and number of refinement for each cells.
3	HXFIN, HYFIN, HZFIN	Dictate the size ratios of each cell in a local grid refinement. It should be placed after the CARFIN keyword introducing the local grid and before the terminating ENDFIN.
4	NXFIN, NYFIN, NZFIN	Dictate how many local cells each of the global cells is divided into. The keyword should beplaced after the keyword CARFIN introducing the local grid, and before the local grid data is terminated with ENDFIN.
5	ENDFIN	Remark end of local grid refinement.
6	WELSPECL and COMPDATL	WELSPECL is proportional to WELSPECS keyword and COMPDATL is proportional to COMPDAT keyword.

In Case A.0, ECLIPSE simulation is done by perforating each layer of reservoir. Fluid properties in ECLIPSE is set to be the same as calculated in BRILLIANT. ECLIPSE only uses one model in the simulation (porosity flow) and does not model dispersion flow inside the well. Therefore, ECLIPSE creates less grid block number compared to BRILLIANT and has a shorter simulation runtime. Grid refinement and fluid properties used in ECLIPSE is showed in **Table 4.8**. Cross section of reservoir is showed in **Figure 4.3**.

Table 4.8: Grid Refinement and Fluid Properties in ECLIPSE Case A.0

No.	Grid Refinement and Fluid Properties in ECLIPSE	Value
1	**GLOBAL GRID**	
	nx	9
	Δx	200, 100, 4*60, 100, 200 m
	ny	9
	Δy	200, 100, 4*60, 100, 200 m
	nz	4
	Δz	5 m
2	**LOCAL GRID**	
	nx	5
	Δx	16.5, 12.5, 1.5, 12.5, 16.5 m
	ny	5
	Δy	16.5, 12.5, 1.5, 12.5, 16.5 m
	nz	4
	Δz	5 m
3	**PROPERTIES**	
	Fluid viscosity, μ	0.556 cP
	Total compressibility, c_t	3.87E-5 /bar

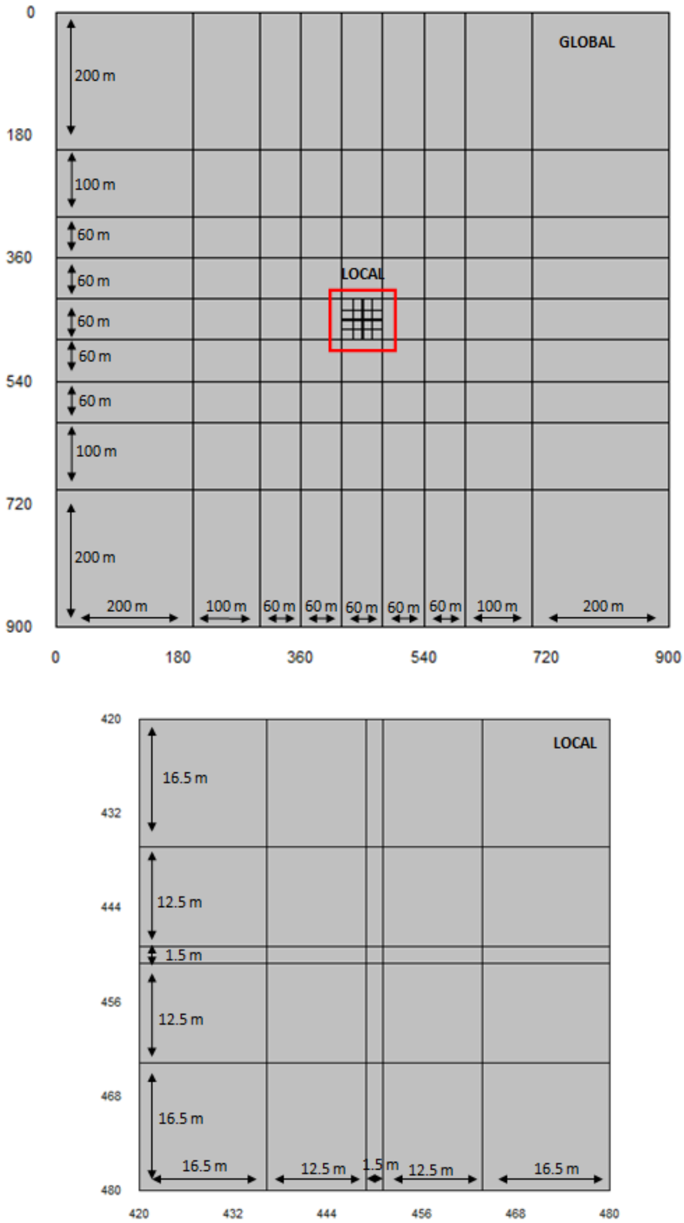

Figure 4.3: XY Cross Section in ECLIPSE Case A.0

Pressure change in ECLIPSE Case A.0 as a function of distance is showed in **Figure 4.4**.

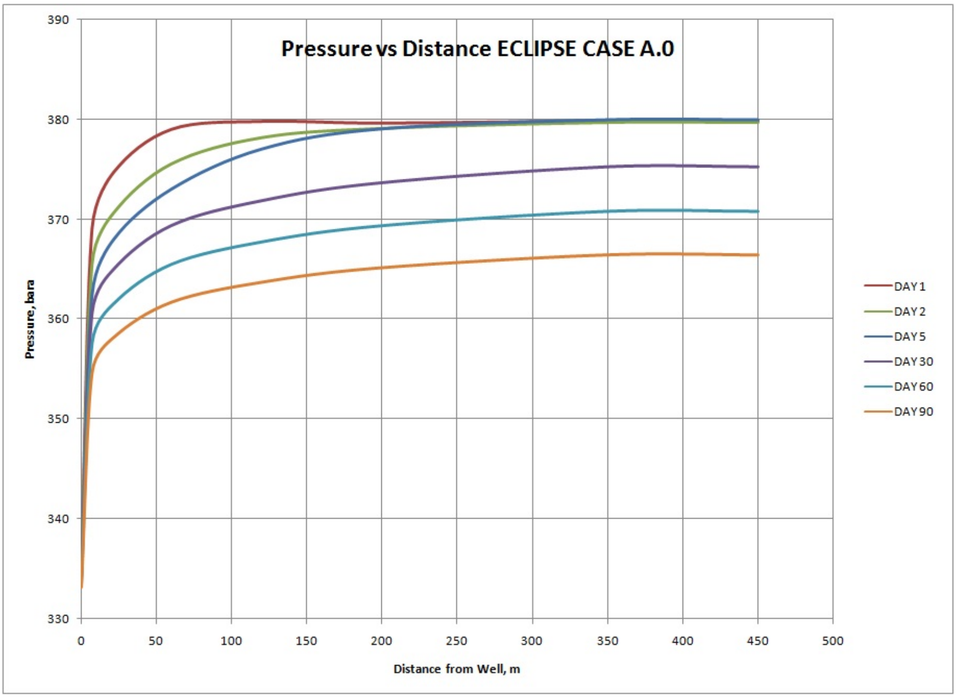

Figure 4.4: Pressure Change in Reservoir As a Function of Distance BRILLIANT Case A.0

Figure 4.4 shows that reservoir boundary is reached after t = 432000 s (5 days). The transient flow period occurs before 5 days, and the boundary flow period occurs after that. Reservoir pressure depletes from 380 bar to 366 bar in 90 days. The quick transition period between transient flow and boundary flow might be caused by small reservoir area and high compressibility value of water as the only fluid present in reservoir. High compressibility value causes fast reservoir pressure depletion. The condition is aggravated further by the absence of reservoir pressure maintenance. Consequence of this condition makes flow rate decreases fast and causes low recovery factor.

4.2.2 BRILLIANT Model Description for Case A.0

BRILLIANT uses two flows model: porosity flow (in reservoir) and dispersion flow (inside well) for Case A.0. There is no casing set, so it is an open hole completion. Grid refinement used in BRILLIANT is showed in **Table 4.9**. Simulation parameter is showed in **Table**

4.10. Fluid properties is calculated automatically based on thermodynamics fluid package in BRILLIANT. Cross section of reservoir is showed in **Figure 4.5**.

Table 4.9: Grid Refinement in BRILLIANT Case A.0

No.	**Grid Refinement and Fluid Properties in BRILLIANT**	**Value**
1	**OUTER RESERVOIR**	
	model	porosity flow
	shape geometry	block
	nx	18
	Δx	50 m
	ny	18
	Δy	50 m
	nz	4
	Δz	5 m
2	**INVADED RESERVOIR**	
	model	porosity flow
	shape geometry	cylinder outer
	cylinder periphery	8
	nθ	2
	$\Delta\theta$	22.5°
	nr	6
	Δr	2 m
	nz	4
	Δz	5 m
3	**WELL BORE**	
	model	dispersion flow
	shape geometry	cylinder inner
	nθ	1
	$\Delta\theta$	22.5°
	nr	1
	Δr	0.2 m
	nz	40
	Δz	0.5 m

Table 4.10: Simulation Parameter in BRILLIANT Case A.0

No.	Parameter	Value	Remarks
1	Max. Timestep	0.005 30 1 60 5 4800 20 86400 600	
2	Courant number	1	
3	Model location [CV]	-450 -450 -20450 450 0	
4	Well location [CV]	0 0 -20 0 0 0	
5	Boundary condition location [CV]	-well_id/2 -well_id/2 -layer1/40 well_id/2 well_id/2 0	well bore
6	Ref. point (current model)	0 0 0	well bore
7	Ref. point (other model)	-0.039 0.119 -10.524	invaded reservoir
8	Inactivate criteria	1000 Pa	
9	Reactivate criteria	1000 Pa	

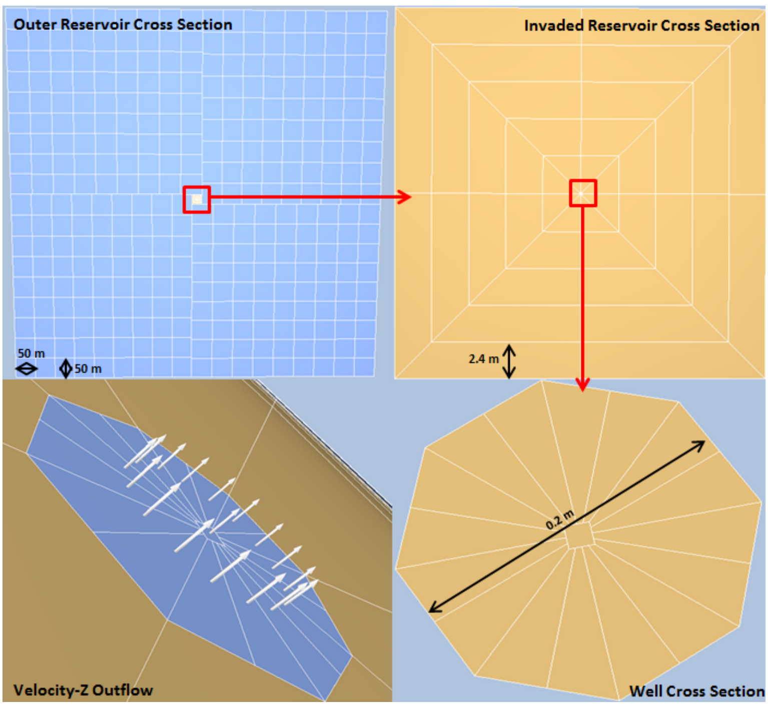

Figure 4.5: XY Cross Section in BRILLIANT Case A.0

Pressure change in BRILLIANT Case A.0 as a function of distance is showed in **Figure 4.6**.

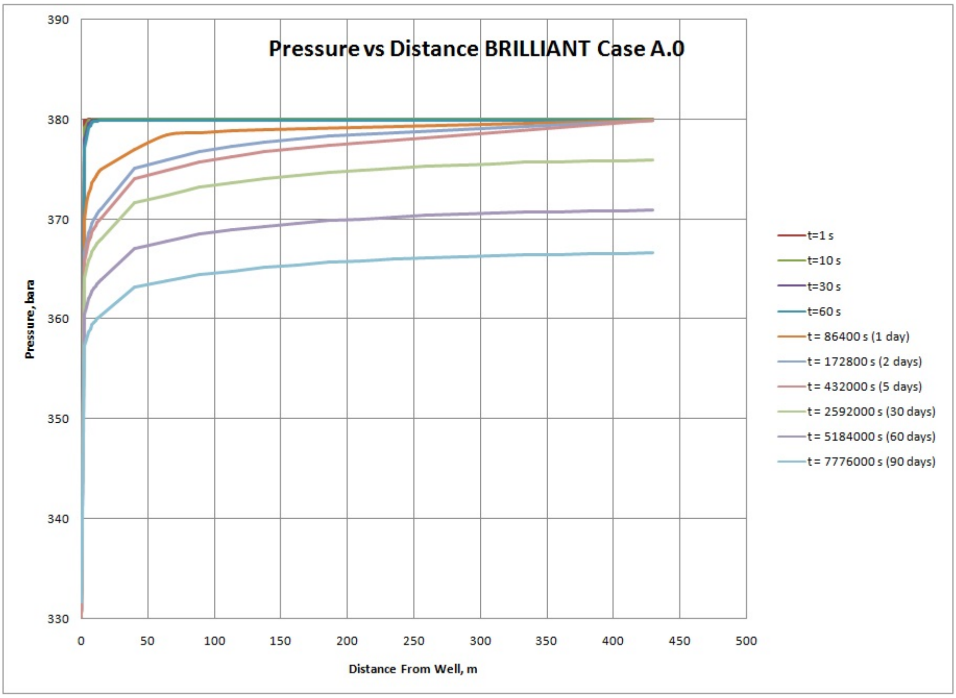

Figure 4.6: Pressure Change in Reservoir As a Function of Distance BRILLIANT Case A.0

Figure 4.6 shows that reservoir boundary is reached after t = 432000 s (5 days). The transient flow period occurs before 5 days, and boundary flow period occurs after that. Reservoir pressure depletes from 380 bar to 366 bar in 90 days. This pressure depletion profile resulted in BRILLIANT has the same pattern with ECLIPSE (**Section 4.2.1**).

4.2.3 ECLIPSE and BRILLIANT Comparison

For Case A.0, ECLIPSE and BRILLIANT simulation result is compared during 90 days production. One vertical production well is drilled in the center of reservoir, and no injector well is drilled. Production comparison and difference between the two simulation software are showed in **Table 4.11**.

Table 4.11: Comparison Result Case A.0

TIME DAYS	FWPRECL SM3/DAY	FWPRBRI SM3/DAY	%diff	FPRECL BARA	FPRBRIL BARA	%diff
0	0.0	0.0	0.0%	380.8	380.0	0.2%
3	63.1	54.4	14.6%	380.6	380.7	0.0%
6	55.4	52.7	5.8%	380.0	380.3	0.1%
9	53.9	51.7	5.1%	379.5	379.8	0.1%
12	52.9	51.1	4.3%	378.9	379.2	0.1%
15	52.1	50.4	4.1%	378.4	378.7	0.1%
18	51.3	49.8	3.9%	377.9	378.1	0.1%
21	50.6	49.2	3.8%	377.3	377.6	0.1%
25	50.0	48.6	3.6%	376.7	376.8	0.0%
28	49.3	47.9	3.5%	376.2	376.3	0.0%
31	48.5	47.4	3.1%	375.7	375.7	0.0%
34	47.9	46.9	3.0%	375.2	375.2	0.0%
36	47.5	46.4	2.9%	374.8	374.9	0.0%
39	46.9	46.0	2.9%	374.4	374.4	0.0%
42	46.3	45.4	2.8%	373.9	373.8	0.0%
45	45.7	44.9	2.7%	373.4	373.3	0.0%
48	45.1	44.4	2.6%	372.9	372.8	0.0%
51	44.5	43.9	2.4%	372.5	372.3	0.0%
54	44.0	43.5	1.9%	372.0	371.9	0.0%
57	43.4	43.1	1.7%	371.6	371.4	0.0%
60	42.8	42.6	1.4%	371.1	370.9	0.1%
63	42.3	42.4	0.8%	370.7	370.4	0.1%
66	41.8	41.8	0.8%	370.2	370.0	0.1%
69	41.2	41.4	0.7%	369.8	369.5	0.1%
72	40.7	41.1	0.1%	369.4	369.1	0.1%
75	40.2	40.4	0.5%	368.9	368.7	0.1%
78	39.7	39.9	0.4%	368.5	368.2	0.1%
81	39.0	39.3	0.6%	368.1	367.9	0.1%
84	38.5	38.9	0.3%	367.7	367.4	0.1%
87	38.2	38.5	0.2%	367.3	367.0	0.1%
90	37.7	38.2	0.4%	366.9	366.6	0.1%

Comparison Result using BRILLIANT and ECLIPSE is showed in **Figure 4.7**.

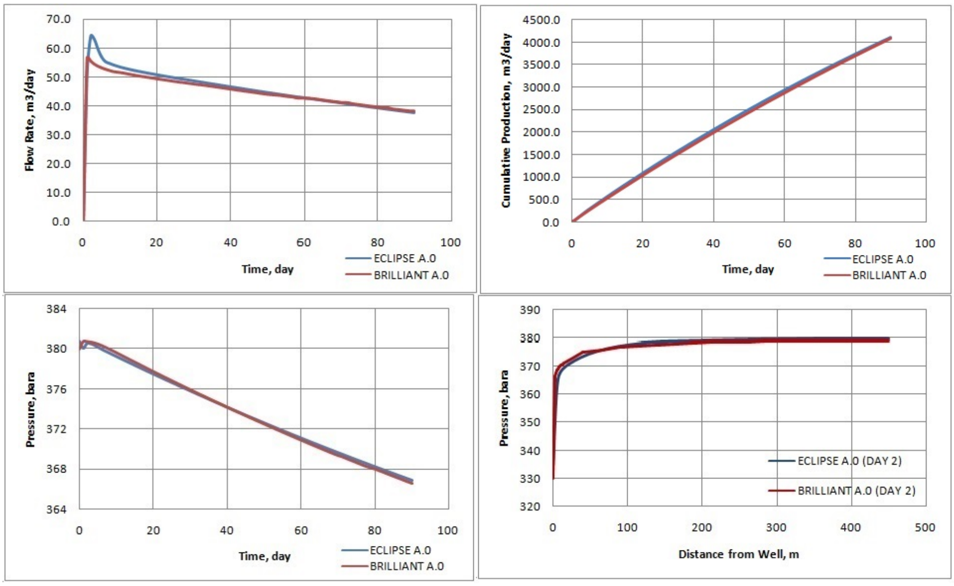

Figure 4.7: Comparison Result BRILLIANT and ECLIPSE Case A.0

The result shows a good match between ECLIPSE and BRILLIANT comparison in terms of flow rate, total production, and pressure characteristics between the two softwares, with difference only 1%, for the specific ECLIPSE grid refinement. The closeness of the BRILLIANT model to the ECLIPSE model result is an indication that the comparison method used is quite successful. It premises that BRILLIANT is valid to simulate fluid flow in reservoir and thus good enough to simulate fishbone in later simulation case.

The validity of BRILLIANT software is limited to single phase flow (water), as multi-phase flow in BRILLIANT is still under development. Fluid behavior has a great influence in simulation result, so further research of BRILLIANT validation for multiphase flow is expected in the future.

4.3 Fishbone Stimulation Case

After Case A.0 is done for validation purpose, BRILLIANT and ECLIPSE are compared for a fishbone case. As stated in previous section, ECLIPSE simulation might simplify several physical phenomena, such as flow turbulence from annulus to fishbone port and fishbone dimension. Case A.1 is built to quantify simulation result difference between ECLIPSE and BRILLIANT in one layer reservoir fishbone stimulation. Case A.1 description summary is showed in **Table 4.12**.

Table 4.12: Case A.1 Description

No.	**Parameter**	**Value**
1	Reservoir Area	900x900 m^2
2	Thickness	20 m
3	P_R	380 bar
4	P_{bh}	330 bar
5	Fluid	Water
6	Porosity	40%
7	Permeability (k_v, k_h)	10 mD
8	Production Mode	Constant Pressure
9	Well Position	Center, Vertical
10	Number of Well	1 (Production)
11	Temperature	323 K
12	Fishbone Number	4
13	Fishbone Length	12 m
14	Fishbone Diameter	0.02 m
15	Port Diameter	0.02 m
16	Fishbone to Port Distance	1 m
17	Initial Fluid Volume	6.48 Mm^3

4.3.1 ECLIPSE Model Description for Case A.1

ECLIPSE grid refinement for Case A.1 is identical with Case A.0 (**Figure 4.3**) with additional connection in layer 3 (for fishbone connection needles). Grid refinement and fluid properties used in ECLIPSE is showed in **Table 4.13**. Well to reservoir grid connection in ECLIPSE is showed in **Figure 4.8**.

Table 4.13: Grid Refinement and Fluid Properties in ECLIPSE Case A.1

No.	Grid Refinement and Fluid Properties in ECLIPSE	Value
1	**GLOBAL GRID**	
	nx	9
	Δx	200, 100, 4*60, 100, 200 m
	ny	9
	Δy	200, 100, 4*60, 100, 200 m
	nz	5
	Δz	4 m
2	**LOCAL GRID**	
	nx	5
	Δx	16.5, 12.5, 1.5, 12.5, 16.5 m
	ny	5
	Δy	16.5, 12.5, 1.5, 12.5, 16.5 m
	nz	5
	Δz	4 m
3	**PROPERTIES**	
	Fluid viscosity, μ	0.556 cP
	Total compressibility, c_t	3.87E-5 /bar

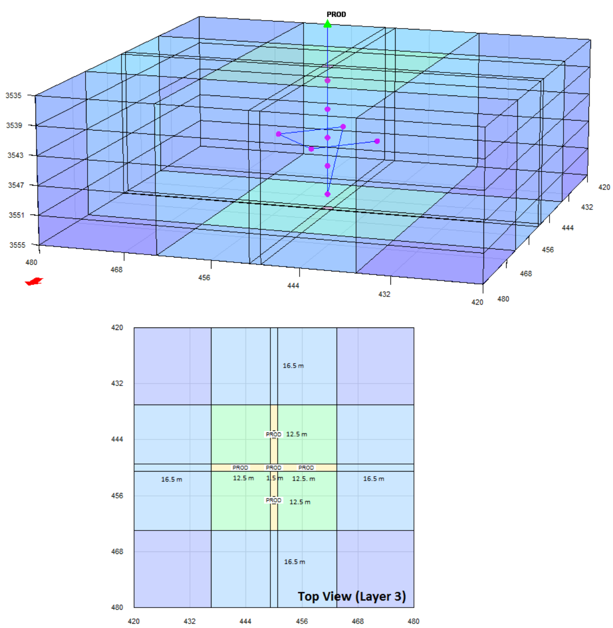

Figure 4.8: Well to Reservoir Grid Connection Case A.1

4.3.2 BRILLIANT Model Description for Case A.1

BRILLIANT model is built using two flow models: porosity flow (in reservoir) and dispersion flow (well). As stated in **Chapter 2.6**, fishbone is an open hole completion. Fishbone liner subs are modeled using conduction model. In this case, conduction model is a neutral model because reservoir condition is assumed to be isothermal.

Fishbone is extended through the invaded reservoir. Each liner sub consists of 4 fishbone needles. Length of each fishbone needle is 12 m. Flow from reservoir goes through fishbone annulus and continues to well annulus. Flow goes into the well via liner port hole. Flow direction from fishbone annulus to fishbone port into well is showed in **Figure 4.9**.

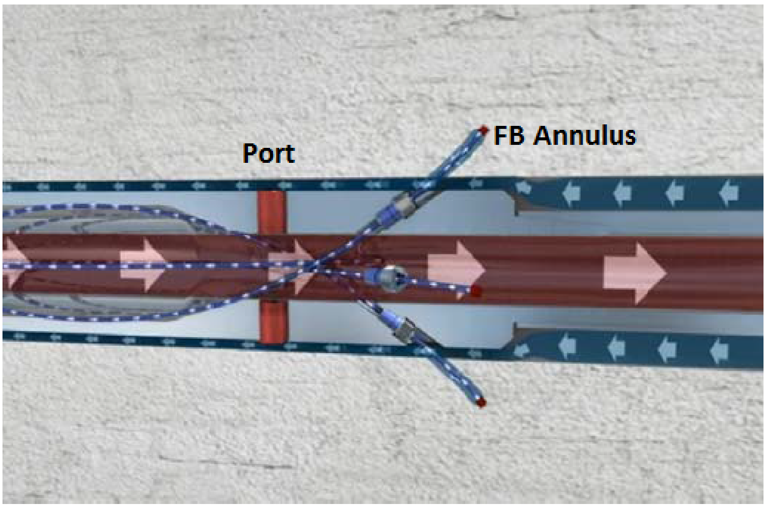

Figure 4.9: Fishbone Velocity Flow Direction (FishbonesAS, 2012)

For correct modeling, #**EXTRACT** command should be used in some models. For example, liner port hole model is constructed by extracting a part of liner casing and replace it with well model. Grid refinement used in BRILLIANT is showed in **Table 4.14**. Simulation parameter is showed in **Table 4.15**. Fluid properties is calculated automatically based on fluid package in BRILLIANT. Cross section of reservoir and fishbone is showed in **Figure 4.10**, **Figure 4.11**, and **Figure 4.12**.

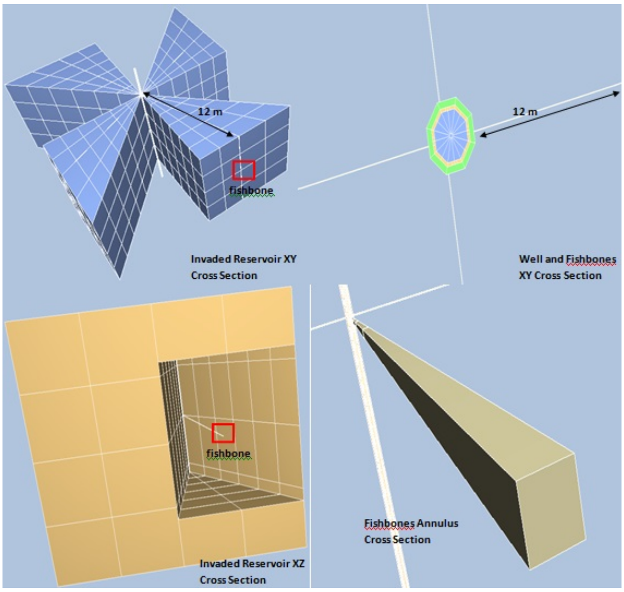

Figure 4.10: Cross Section Reservoir BRILLIANT Case A.1

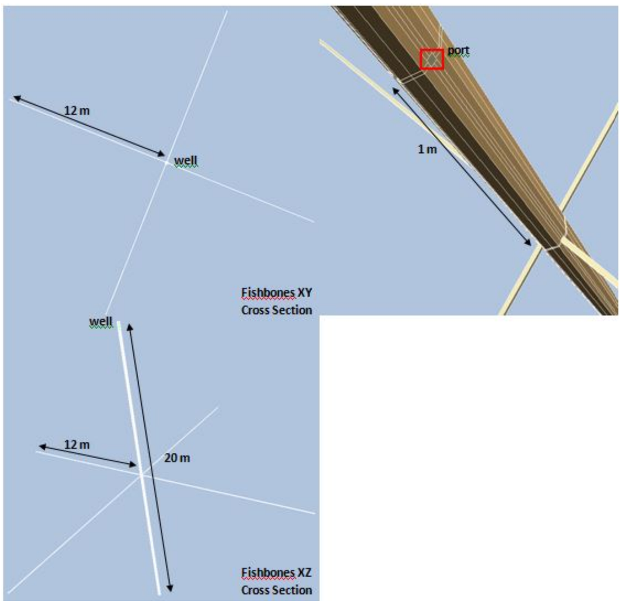

Figure 4.11: Cross Section Fishbone BRILLIANT Case A.1

Table 4.14: Grid Refinement in BRILLIANT Case A.1

No.	Grid Refinement and Fluid Properties in BRILLIANT	Value
1	**OUTER RESERVOIR**	
	model	porosity flow
	shape geometry	block
	nx, Δx	20, 45 m
	ny, Δy	20, 45 m
	nz, Δz	4, 5 m
2	**INVADED RESERVOIR**	
	model	porosity flow
	shape geometry	cylinder outer
	cylinder periphery	8
	nθ, $\Delta\theta$	2, 22.5°
	nr	6
	Δr	2 m
	nz	4
	Δz	5 m
3	**WELL BORE**	
	model	dispersion flow
	shape geometry	cylinder inner
	cylinder periphery	8
	nθ, $\Delta\theta$	2, 22.5°
	nr	1
	Δr	0.2 m
	nz	40
	Δz	0.5 m
4	**WELL BORE ANNULUS**	
	model	dispersion flow
	shape geometry	cylinder outer
	cylinder periphery	8
	nθ, $\Delta\theta$	2, 22.5°
	nr	1
	Δr	0.2 m
	nz	40
	Δz	0.5 m
5	**FISHBONE ANNULUS**	
	model	dispersion flow
	shape geometry	block
	nx	1
	Δx	0.02 m
	ny	8
	Δy	1.5 m
	nz	1
	Δz	0.02 m

Table 4.15: Simulation Parameter in BRILLIANT Case A.1

No.	Parameter	Value	Remarks
1	Max. Timestep	0.005 30 1 60 5 4800 20 86400 600	
2	Courant number	1	
3	Model location [CV]	-450 -450 -20 450 450 0	
4	Well location [CV]	0 0 -20 0 0 0	
5	Boundary condition location [CV]	-well_id/2 -well_id/2 -layer1/40 well_id/2 well_id/2 0	well bore
6	Ref. Point (current model)	0.4669 -1.1153 -9.985	fishbone annulus
7	Ref. point (other model)	400 400 0	outers reservoir
8	Inactivate criteria	1000 Pa	
9	Reactivate criteria	1000 Pa	

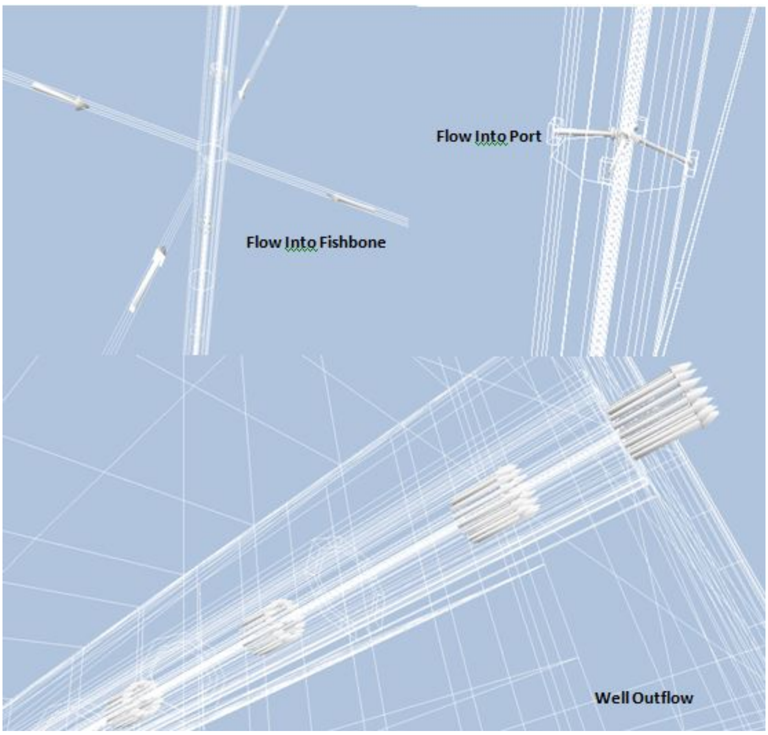

Figure 4.12: Velocity Flow in BRILLIANT Case A.1

4.3.3 BRILLIANT and ECLIPSE comparation for Case A.1

Comparison between BRILLIANT and ECLIPSE simulation in terms of flow rate, cumulative production, and pressure for Case A.1 is showed in **Figure 4.13**.

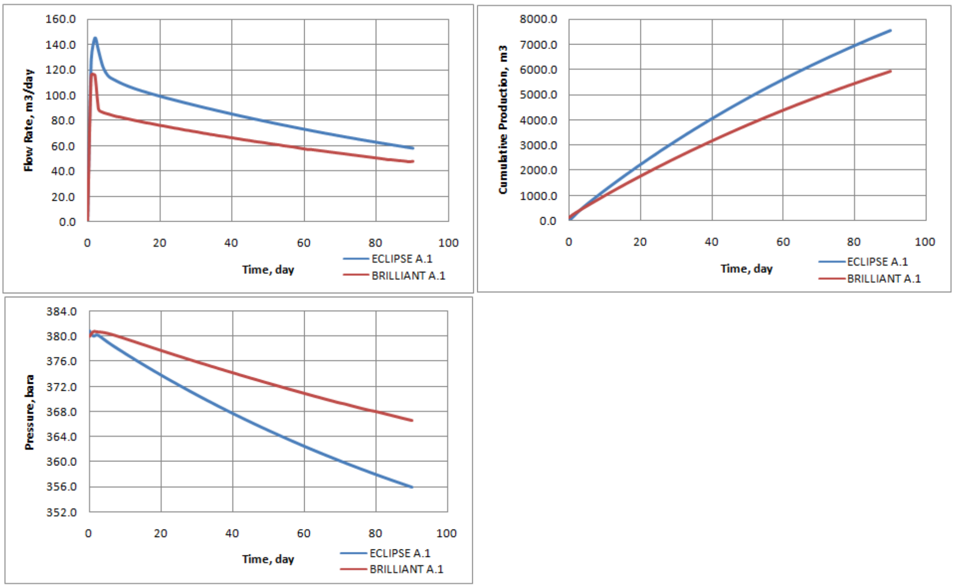

Figure 4.13: Flowrate and Cumulative Production Comparison Case A.1

Figure 4.15 shows that ECLIPSE simulation gives a greater flow rate value by about 20% compared to BRILLIANT simulation. The difference could be caused by ECLIPSE inability to capture detail fishbone flow from annulus to port and towards fishbone needles, neglect the turbulence near well bore due to the high velocity flow, and therefore fail to calculate correct pressure drop near the well bore.

Flow rate in a few first days is very high, however it goes down drastically after day 5 in both simulation. This happens because transient (infinite acting) reservoir phase has been over and flow has reached reservoir boundary. Reservoir pressure depletion causes drastic flow rate decrease in BRILLIANT and ECLIPSE simulation as bottom hole pressure is kept constant.

One of the purposse of the work is to input (upscale) BRILLIANT result into ECLIPSE simulation to ensure accurate flow calculation in the reservoir for fishbone case. Among other methods, it could be done by emulating reservoir properties (permeability) for ECLIPSE

Case A.0 or increase skin factor for ECLIPSE Case A.1. These two methods will be discussed in the next section.

4.3.3.1 Permeability Modification to Mimic Fishbone Stimulation

BRILLIANT could support ECLIPSE inability to capture fishbone flow phenomena in fishbone simulation. The procedure is to use BRILLIANT result as an input to ECLIPSE in order to match well production in fishbone stimulation. One of the methods is to increase permeability value near well bore to match the equivalent conditions in BRILLIANT. After several trial, it is found that permeability value 18 mD could be used in the grid block near well bore for ECLIPSE Case A.0 to match BRILLIANT simulation. Result of simulation after permeability value has been changed is showed in **Figure 4.14**. After permeability is modified, flow rate between ECLIPSE and BRILLIANT is matched within 6.5% and cumulative production is matched within 1.1%.

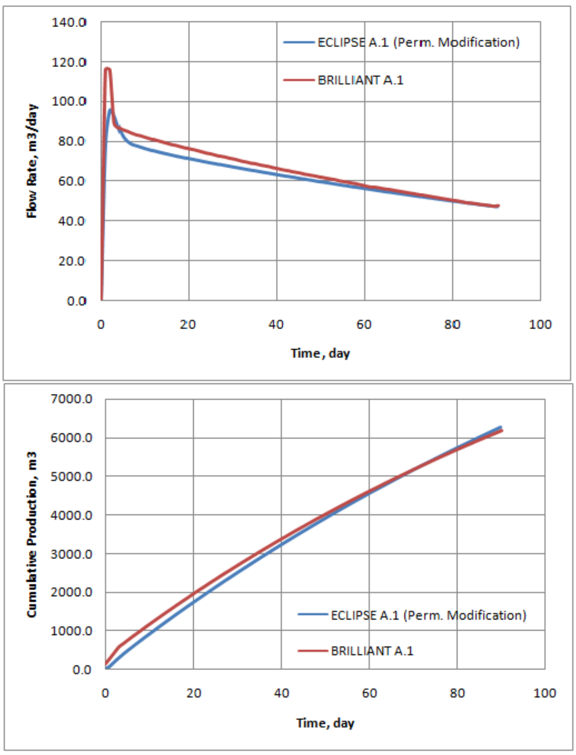

Figure 4.14: Flow Rate and Cumulative Production Comparison in Modified Permeability Case A.1

4.3.3.2 Skin Factor Modification to Mimic Fishbone Stimulation

Another method to mimic fishbone stimulation in ECLIPSE is by increasing skin factor. It is found that by changing skin factor to 6 in ECLIPSE Case A.1 will result in relatively matched flow rate and cumulative production between ECLIPSE and BRILLIANT. Result of change skin factor is showed in **Figure 4.15**. After skin factor is modified, flow rate between ECLIPSE and BRILLIANT is matched within 7.5% and cumulative production is matched within 1.1%.

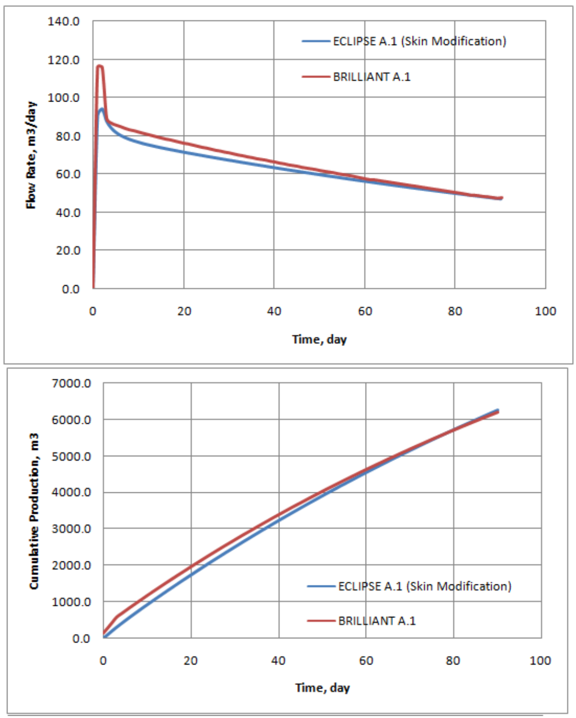

Figure 4.15: Flow Rate and Cumulative Production Comparison in Modified Skin Factor Case A.1

CHAPTER 5

Simulation Study of Fishbone Performance

The following chapter will study and investigate the effectiveness of fishbone performance in various conditions in terms of flow rate and cumulative production. Parameters are furtherly divided into: controllable parameters and uncontrollable parameters. Controllable parameters are the operational parameters of fishbone stimulation itself, including number of fishbone needle, fishbone annulus diameter size, and fishbone length. Uncontrollable parameters are related to reservoir properties, including reservoir thickness and reservoir heterogeneity (vertical and horizontal barrier). The chapter will furtherly compare fishbone and conventional fracturing stimulation performance in terms of flow rate and cumulative production. All simulations are conducted in BRILLIANT software as it has the ability to cope with many kinds of variation. In the end of the chapter, I simulate fishbone in multi-layer reservoir to test BRILLIANT simulator capability in terms of simulation time and simulation result.

5.1 Controllable Parameters Effect

Uncertainties in fishbone performance incorporate in fishbone operation itself. For example whether all the needles are fully extended, especially in a hard formation. Acid amount that reacts with reservoir rock to form fishbone annulus also influences fishbone dimension. Uncertainties in operation determine fishbone dimension and its performance consequently. In below cases, I quantify effect of fishbone dimension to its performance. Variations include number of fishbone needles per liner sub, fishbone annulus diameter size, and fishbone length. All sensitivity cases are compared to fishbone Base Case A.1.

5.1.1 Number of Fishbone Needles

In below section, number of fishbone needles are varied to see the effect to flow rate and cumulative production. I would like to calculate how much increment is given by one fishbone needle compared to zero, two, and four needles. All other parameters remain constant as Base Case A.1. Description of sensitivity case is showed in **Table 5.1**. Simulation result is presented in **Picture 5.1**.

Cumulative production in Case A.2 (no needle) is 35% lower compared to Base case A.1. Flow from fishbone annulus disappears as fishbone needles are removed in Case A.2. This causes flow area in Case A.2 decrease and causes higher pressure drop in vicinity of the well.

Fishbone needles increment from zero needle (Case A.2) to one needle (Case A.3) causes 21% higher in cumulative production. However, needles increment from one (Case A.3) to two needle (Case A.4) only increases total cumulative production 8% higher. Furthermore, needles increment from two needles (Case A.4) to four needles (Base Case A.1) only increases 6% in cumulative production. These results show that significant amount of increased productivity comes mainly from the first needle. Second, third, and fourth needle has a smaller effect in increasing well productivity.

The decrease trend in cumulative production increment might be also related to pressure depletion. Pressure depletion in reservoir causes lower drawdown and lower flow rate in constant bottom hole pressure condition. The phenomena is confirmed by decreased flow rate in Case A.1, A.3, and A.4 in **Figure 5.1** as reservoir pressure depletes. Problem of pressure depletion should be addressed with pressure maintenance project like water or gas injection.

Table 5.1: Sensitivity Case for Fishbone Needle Number

Variable	**Case A.1**	**Case A.2**	**Case A.3**	**Case A.4**
Number of Fishbone Needle Number	4	0	1	2
Cum. Prod. Result to Base Case	0%	-35%	-14%	-6%

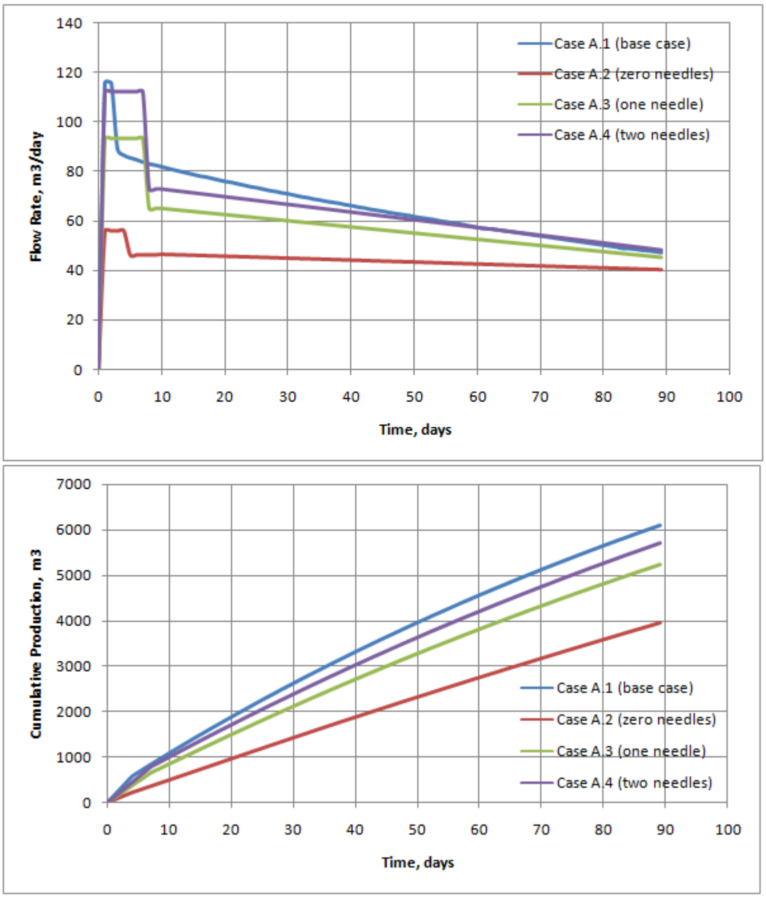

Figure 5.1: Sensitivity Analysis for Parameter Fishbone Needle Number

5.1.2 Fishbone Annulus Diameter Size

Fishbone annulus diameter size is one of the uncertainties in fishbone operation. Reaction between rock and acid will create channel that allows reservoir fluid flow afterwards.

The channel size depends on reaction between rock and acid in the reservoir. Therefore, type of acid, acid concentration, reservoir rock mineral, and temperature will influence the annulus size in fishbone stimulation. Typical fishbone diameter annulus size in fishbone operation is between 0.01 - 0.02 m (FishbonesAS, 2012). In below section, fishbone annulus diameter size is varied to see the effect of flow rate and cumulative production for 0.015, 0.02, and 0.025 m diameter size. Description of sensitivity case is showed in **Table 5.2**. Simulation result is presented in **Picture 5.2**.

Case A.5 result in 5% decrease of total cumulative production by reducing fishbone annulus diameter by 25% (D = 0.015 m). Case A.6 result in 4% increase of total cumulative production by increasing fishbone annulus diameter by 25% (D = 0.025 m). Fishbone annulus diameter size has a relatively small effect for fishbone performance, however correct design of operation condition should be conducted as well.

The percentage of increment in Case A.6 is smaller compared to percentage of decrease in Case A.5 for the same variable change. This is also related to pressure depletion propblem. Problem of pressure depletion should be addressed with pressure maintenance project like water or gas injection.

Table 5.2: Sensitivity Case for Fishbone Needle Number

Variable	Case A.1	Case A.5	Case A.6
Fishbone Annulus Diameter (m)	0.02	0.015	0.025
Cum. Prod. Result to Base Case	0%	-5%	+4%

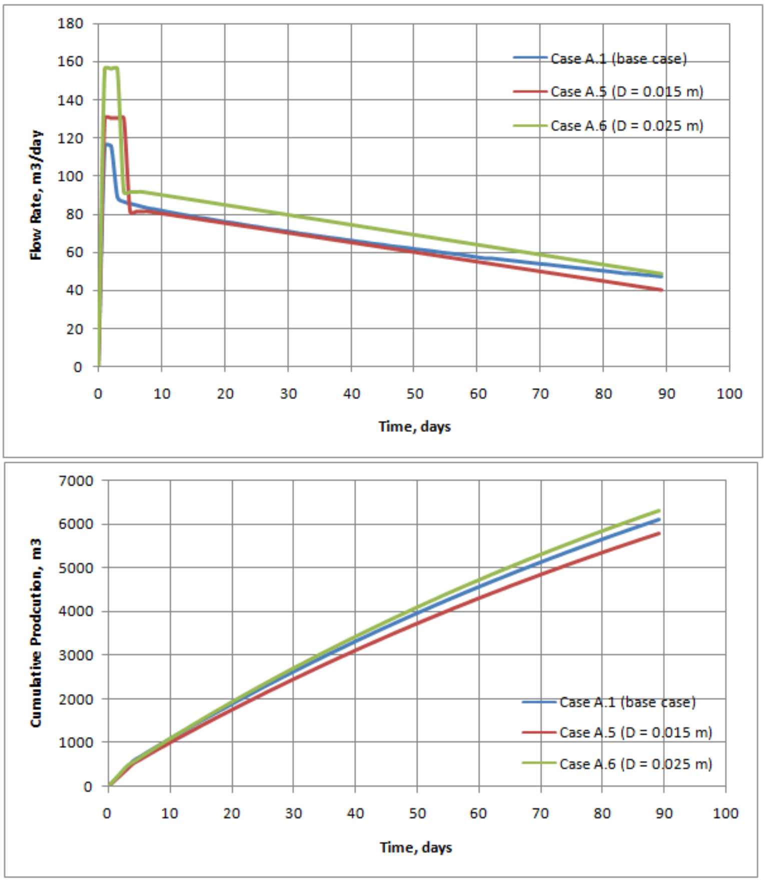

Figure 5.2: Sensitivity Analysis for Parameter Fishbone Annulus Diameter

5.1.3 Fishbone Needles Length

In below section, fishbone needles length is varied to see the effect of flow rate and cumulative production. Length of fishbone is limited to less than 12 m as it is described in fishbone product specification. In reality, fishbone needle might be not fully extended because of the hard rock reservoir or cemented layer. This sensitivity has a purpose to analyze effect of fishbone length to its performance. Fishbone length is varied into 8 and 10 m length. Description of sensitivity case is showed in **Table 5.3**. Simulation result is presented in **Picture 5.3**.

Case A.7 results in 10% decrease of total cumulative production by reducing fishbone needles length by 16% (L = 10 m). Case A.8 results in 13% decrease of total cumulative production by reducing fishbone needle lsength by 32% (L = 8 m). Fishbone needles length has a moderate effect for fishbone performance. Therefore, rock strength in vicinity of the well should be accurately predicted before justifying a fishbone operation.

Table 5.3: Sensitivity Case for Fishbone Needle Number

Variable	Case A.1	Case A.7	Case A.8
Fishbone Length (m)	12	10	8
Cum. Prod. Result to Base Case	0%	-10%	-13%

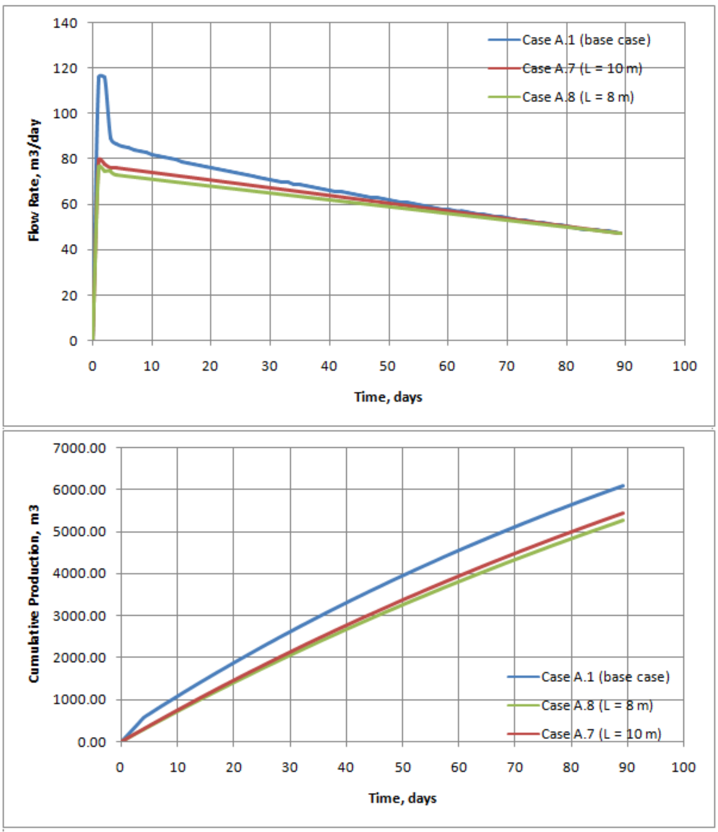

Figure 5.3: Sensitivity Analysis for Parameter Fishbone Length

5.2 Uncontrollable Parameters Effect

Uncertainties in fishbone performance is strongly related to reservoir properties as well. Parameters in reservoir properties that related to rock or fluid properties determine well performance in some extent, and this can not be controlled in fishbone operation. In below cases, I quantify effect of reservoir properties parameter related to fishbone performance. Output of the simulation determine suitable reservoir properties for fishbone operation. Parameters in reservoir properties include reservoir thickness and heterogeneity. Heterogeneity in reservoir is furtherly classified as vertical and horizontal heterogeneity (barrier). All sensitivity cases are compared to fishbone Base Case A.1.

5.2.1 Reservoir Thickness

In below section, reservoir thickness is varied to see the effect of flow rate and aumulative production, by keeping the amount of reservoir fluid constant. Sensitivity for reservoir thickness of 30 and 10 m is conducted. Description of sensitivity case is showed in **Table 5.4**. Simulation result is presented in **Picture 5.4**.

Case A.9 with reservoir thickness is increased 50% (h = 30 m) results in 23% cumulative production increase, while Case A.10 with reservoir thickness is decreased 50% (h = 10 m) results in 15% cumulative production decrease compared to Base Case A.1. Thicker layer is more effective for fishbone stimulation compared to corresponding thinner layer and wider reservoir. Fishbone needles has a limitation in length, as it could only extend up to 12 m. Therefore, wider reservoir with thinner layer has a disadvantage in fishbone operation, as fishbone needles is not capable to reach into deeper reservoir.

Table 5.4: Sensitivity Case for Reservoir Thickness

Variable	Case A.1	Case A.9	Case A.10
Reservoir Thickness (m)	20	30	10
Reservoir Area (m)	900x900	735x735	1273x1273
Initial Fluid Volume (Mm^3)	6.48	6.48	6.48
Cum. Prod. Result to Base Case	0%	+23%	-15%

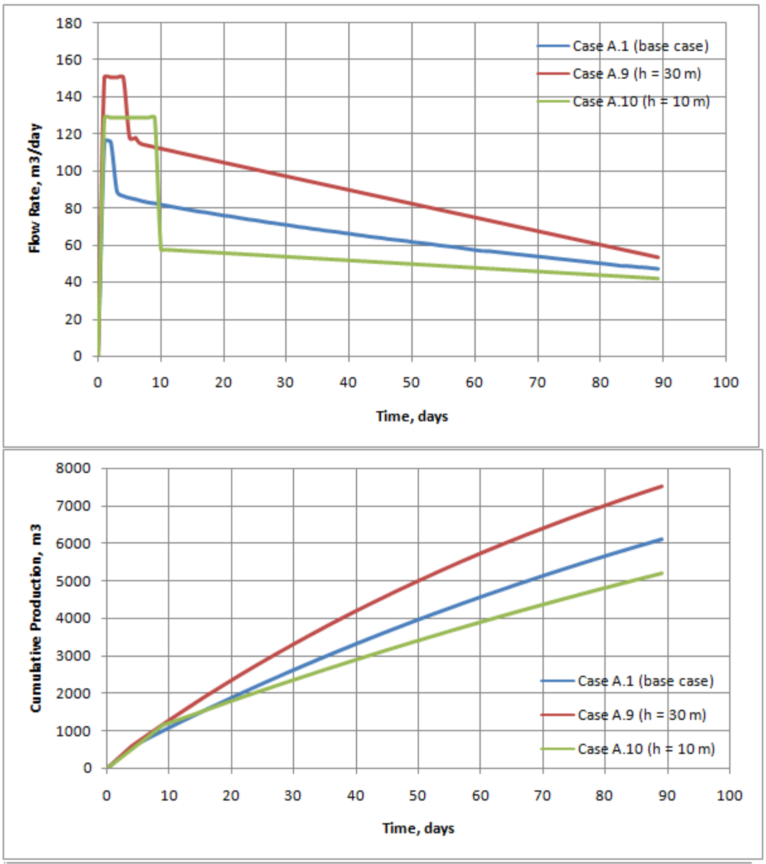

Figure 5.4: Sensitivity Analysis for Parameter Reservoir Thickness

5.2.2 Reservoir Heterogeneity

In below section, reservoir heterogeneity is varied to see the effect of flow rate and cumulative production. Vertical and horizontal heterogeneity are created in reservoir cells around fishbone and act as a barrier (low permeability).

Vertical barrier is created in second and fourth vertical layer, with horizontal and vertical permeability of 1 mD each (Case A.11). Horizontal barrier is created in second, fourth, and sixth horizontal layer around the well, also with horizontal and vertical permeability of 1 mD each (Case A.12). These barriers are created in reservoir cells to analyze effectiveness of fishbone performance in the presence of reservoir heterogeneity. Cross section for vertical and horizontal barrier is presented in **Picture 5.5**. Simulation result is presented in **Picture 5.6**.

Case A.11 (vertical barrier) results in 11% decrease in cumulative production compared to Base Case A.1. This shows that fishbone lateral stimulation is not very effective in the presence of vertical barrier. This result is due to condition that fishbone needles do not connect reservoir in vertical direction effectively. On the other hand, Case A.12 (horizontal barrier) results in only 1% decrease in cumulative production compared to Base Case A.1. This shows that fishbone lateral stimulation effectively connects reservoir in horizontal direction, so that horizontal barrier does not influence fishbone performance significantly. Vertical permeability, k_v and horizontal permeability, k_h ratio is two important parameters that influence fishbone performance. In other words, k_v/k_h value plays an important role to justify effectiveness of fishbone operation in a reservoir. Smaller k_v/k_h value causes less effective fishbone operation compared to bigger k_v/k_h value in a single layer reservoir and vertical well.

Table 5.5: Sensitivity Case for Reservoir Heterogeneity

Variable	**Case A.1**	**Case A.11**	**Case A.12**
Heterogeneity	-	vertical	horizontal
Cum. Prod. Result to Base Case	0%	-11%	-1%

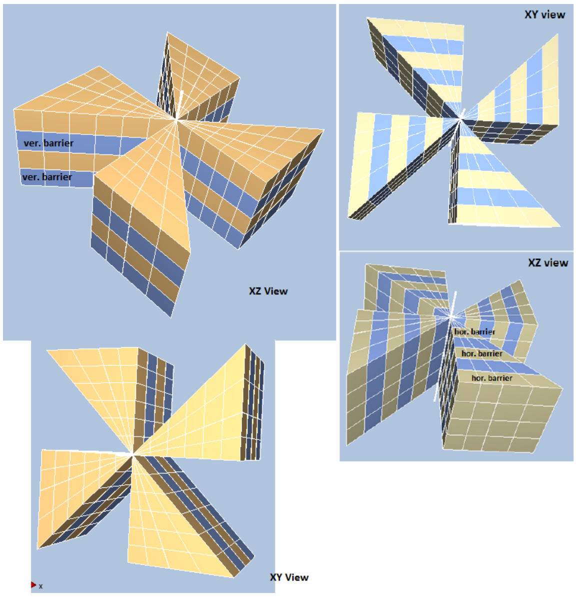

Figure 5.5: Vertical and Horizontal Barrier Cross-Section (Case A.11)

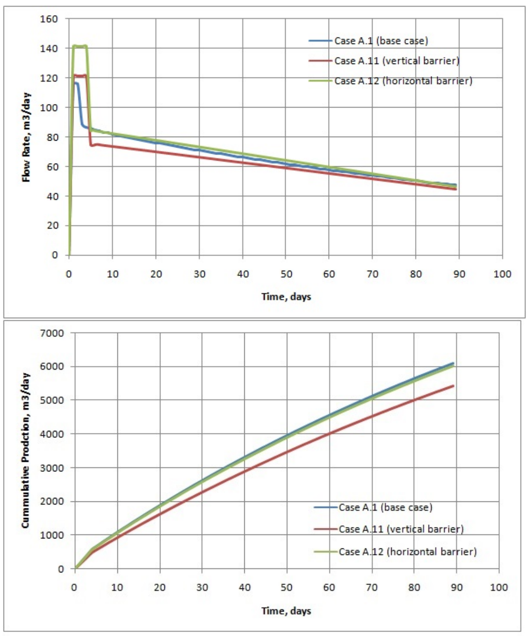

Figure 5.6: Sensitivity Analysis for Parameter Reservoir Heterogeneity

5.3 Comparison of Fishbone and Conventional Fracturing

Hydraulic and acid stimulation are two conventional methods for increasing well performance. Performance increment in acid or hydraulic fracturing is usually quantified with skin factor. In below section, fishbone and conventional fracturing performance is compared in order to select the best options for boosting well performance. Acid/hydraulic fracturing is modeled by increasing equivalent well bore radius using equation below,

$$r_{we} = r_w e^{-S} \tag{5.1}$$

with r_{we} is equivalent well bore radius, r_w is well radius, and S is skin factor.

Hydraulic/acid fracturing is modeled in BRILLIANT by creating an equivalent well bore radius. Calculation from above equation results in equivalent well bore radius 0.40 m and 1.47 m for skin factor -1.05 and -2.35 respectively. Description of sensitivity case is showed in **Table 5.6**. Simulation result is presented in **Picture 5.7**.

Base Case A.1 results in 30% increase in cumulative production compared to Case A.0, however Case A.14 (skin -2.35) results in 47% increase in cumulative production compared to Case A.0. This shows that fishbone Base Case A.1 results in lower well performance compared to conventional fracturing with skin factor -2.35. In other words, hydraulic/acid fracturing with skin factor -2.35 is more effective in increasing well performance compared to fishbone stimulation.

Case A.13 (skin -1.05) represents equivalent skin factor of fishbone stimulation Base Case A.1. Single sub fishbone in 20 m reservoir layer results in skin factor -1.05 based on BRILLIANT simulation. The value is lower than typical skin factor from hydraulic/acid fracturing. A typical skin fracture in a successful fracturing in Ekofisk Field is -4.5 to -5 (Feazel et al., 1990). Reason for this is area created by fishbone annulus is smaller compared to massive small conductive channels in hydraulic/acid fracturing. To achieve the same or more performance, two or more fishbone subs should be extended in a single reservoir layer.

Table 5.6: Sensitivity Case for Fishbone and Conventional Fracturing

Variable	Case A.0	Case A.1	Case A.13	Case A.14
Fishbone	no	yes	no	no
Equivalent Well bore Radius (m)	0.2	0.14	0.40	1.47
Skin Factor (m)	0	N/A	-1.05	-2.35
Cum. Prod. Result to Base Case	-30%	0%	+0.5%	+47%

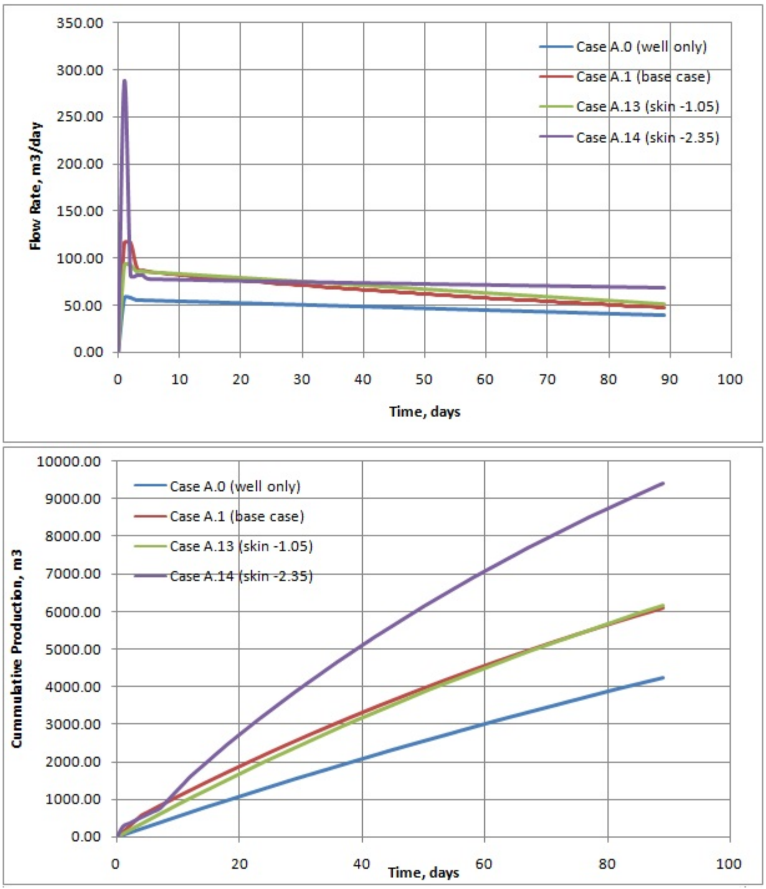

Figure 5.7: Simulation Result with Varied Skin Factor

5.4 BRILLIANT Capability in Multi-Layer Reservoir

In below section, I would like to assess BRILLIANT for simulating fishbone in multilayer reservoir. Multilayer reservoir is closer to reality in oil field operation for fishbone. Procedure to create the model for multi-layer fishbone is conducted by using #**COPY** and #**PASTE** keyword in the previous model. Identical reservoir layer is created by copying previous reservoir section in Base Case A.1.

BRILLIANT is capable in simulating one layer reservoir with simulation runtime 3 hours for 90 days simulation, while two layer reservoir simulation results in 6 hours for 90 days simulation, however BRILLIANT is unsuccessful in simulating three-layer reservoir. Lack of success in three layer reservoir simulation shows that BRILLIANT is still incapable in handling a large number of cells. Description of all case is showed in **Table 5.7**. Cross section for two layer fishbone is presented in **Picture 5.9**. Simulation result is presented in **Picture 5.10**.

Case A.15 (two layer reservoir) results in 52% increase in cumulative production compared to single layer reservoir. The increment does not neccesarily correspond to double (100% increment) production due to increase in friction in a longer well and friction due to bigger flow rate.

Table 5.7: Sensitivity Case for Multi-Layer Reservoir

Variable	**Case A.1**	**Case A.15**	**Case A.16**
Number of Layer	1	2	3
Result	successful	successful	unsuccessful
Run Time (hours)	3	6	N/A

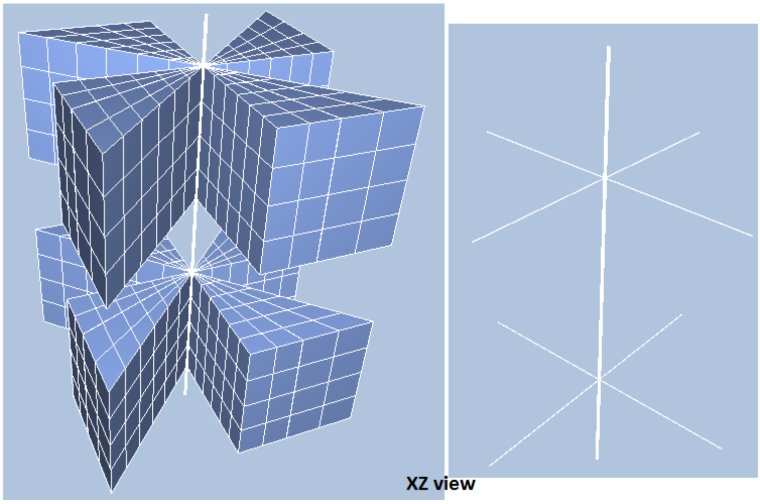

Figure 5.8: Two Layer Reservoir Cross-Section

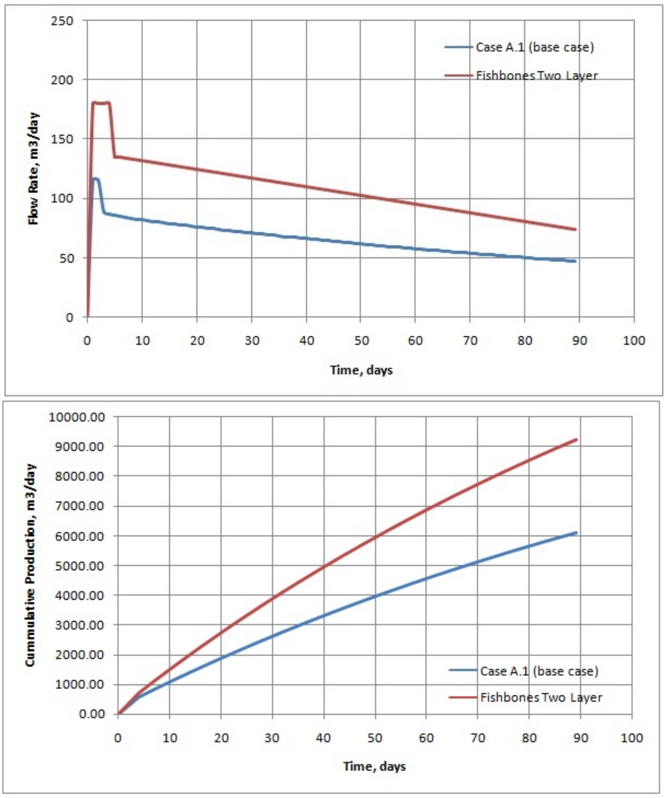

Figure 5.9: Simulation Result in One and Two Layer Reservoir

CHAPTER 6

Discussion Summary

This master thesis has several purposes. The first is to upscale BRILLIANT simulation into ECLIPSE reservoir simulation for fishbone stimulation case. Before upscaling BRILLIANT result, I need to validate BRILLIANT result in a single vertical open hole well. This is done to ensure that calculation algorithm in BRILLIANT for porosity flow (reservoir) and dispersion flow (well) are correct. BRILLIANT and ECLIPSE simulation are compared in a specific Case A.0.

For fishbone case comparison, I made two models, using ECLIPSE and BRILLIANT software. I assumed the result gained from BRILLIANT simulation is correct because BRILLIANT creates two different models (porosity and dispersion) and with its detail gridding and dimension, it takes account of pressure drop near the fishbone annulus, annulus, into fishbone port, and inside well bore. BRILLIANT result is then upscaled as an input into ECLIPSE simulation for the specific fishbone case.

The second purpose is to conduct numerical simulation study for fishbone case. Several parameters are studied in BRILLIANT simulation to see the effect to well performance (in terms of flow rate and cumulative production). The parameters are divided into two categories: controllable parameters and uncontrollable parameters. Controllable parameters include numbers of fishbone needles per sub, fishbone annulus diameter, and fishbone needles length. Uncontrollable parameters include reservoir thickness and vertical/horizontal barrier.

The third purpose is to compare fishbone stimulation and conventional fracturing method such as hydraulic/acid fracturing. Fishbone is provided as an alternative method to conventional fracturing. I investigated result of fishbone stimulation compared to conventional fracturing in terms of well performance enhancement (flow rate and cumulative production). The last purpose is to test BRILLIANT software capability in simulating multi-layer reservoir.

The overall discussion of the aforementioned studies are summarized as follows:

6.1 Upscaling BRILLIANT into ECLIPSE

BRILLIANT and ECLIPSE has their own superiority and drawback in the fishbone simulation work. ECLIPSE as the established reservoir simulation has a capability in doing full field reservoir simulation in longer period of time. ECLIPSE also has a very robust reservoir model to capture a lot of reservoir characteristics that is useful for predicting oil and gas production, such as reservoir heterogeneities and fault models. However, it simplifies a lot of physical phenomena in fluid flow, which makes some assumption that should be taken into account be ignored or neglected. On the other hand, BRILLIANT has an advantage to capture detail phenomena and flow characteristics in the reservoir, but BRILLIANT has a limitation in modeling reservoir properties. Advantages and drawbacks from each simulation software are treated optimally to calculate the most accurate result for fishbones simulation.

Before I do the upscaling process, BRILLIANT simulation is validated with ECLIPSE reservoir simulation to ensure that BRILLIANT calculation algorithm in porosity flow (reservoir) and dispersion flow (well) are correct. Both models are built for a single vertical, open-hole well in a homogeneous reservoir. In ECLIPSE, models are built using Local Grid Refinement (LGR) options, with optimum grid cell size for well connection gained from the last semester project (Appendix C).

Comparison between ECLIPSE and BRILLIANT for Case A.0 results in a good match in terms of flow rate, cumulative production, and pressure. Thus, reservoir simulation result from BRILLIANT result is considered valid. The validity of BRILLIANT software are limited to single phase flow, as multi-phase flow in BRILLIANT is still under development. The further research of multi-phase flow in BRILLIANT is suggested to be carried out in the future.

Afterwards, BRILLIANT and ECLIPSE are compared for fishbone Case A.1 to see effect of flow and pressure drop near well bore, fishbone annulus, and fishbone port opening. ECLIPSE simulation give greater flow rate value by about 20% compared to BRILLIANT simulation. The difference could be caused by ECLIPSE inability to capture detail fishbone flow from annulus to port, neglect the turbulence near well bore due to the high velocity flow, and therefore fail to calculate correct pressure drop near the well bore. BRILLIANT calculation with finer grid block, detail geometry, and several models will result in more accurate simulation result for such a complex system like fishbone.

Different result between BRILLIANT and ECLIPSE suggests an improvement in ECLIPSE simulation for fishbone case. Thus, BRILLIANT could be used as an input for ECLIPSE fishbone simulation. Input from BRILLIANT result is used to calculate skin modifier or permeability modifier in ECLIPSE simulation. For Case A.1, permeability modification of 18 mD near well bore grid in ECLIPSE simulation will match to BRILLIANT simulation. After permeability is modified, flow rate and cumulative production between ECLIPSE and BRILLIANT is matched within 6.5% difference in flow rate and 1.1% in cumulative production.

6.2 Numerical Simulation Study in BRILLIANT

Several simulation models are run to quantify the effect to fishbone performance to evaluate specific parameters in field conditions. The parameters are classified into two parts: controllable and uncontrollable parameters. Controllable parameters are related with fishbone dimensions, such as number of fishbone needles number, fishbone annulus size, and fishbone needles length. All simulations are conducted in BRILLIANT software as the softwre has ability to cope with many kinds of variation.

There are several operational constraints that limit fishbones operation. These parameters are used as boundaries for the sensitivity calculation. First limitation is the maximum length for each fishbone needle. Each fishbone needle length is limited to 12 m. Fishbone needles length is limited by fishbone sub length and surface force power to extract the needles. Second limitation is maximum fishbone needles number for each liner sub. Maximum number of fishbone needle for each liner sub is 4. Third limitation is the size of fishbone annulus. Reaction between rock and acid in fishbone annulus will create fishbone annulus, channels between fishbone needle and formation that allow reservoir fluid to flow afterwards. Typical fishbone diameter annulus size in fishbone operation is between 0.01 - 0.02 m (FishbonesAS, 2012). This value is limited to the maximum reaction between reservoir rock and acid, which is also a function of acid concentration and acid flow rate.

Increment of fishbone needles number, fishbone annulus size, and length will increase well productivity and vice versa. However, these parameters have different magnitude effects for well performance. Fishbone needles increment from zero to one needles has the biggest effect to increase well productivity, while fishbone annulus size has the smallest effect to increase well productivity. Fishbone needles length has a moderate effect for fishbone performance, therefore rock strength in vicinity of the well should be accurately predicted before justifying a fishbone operation.

Uncertainties in fishbone performance are strongly related to reservoir properties as well. Parameters in reservoir properties that related to rock or fluid properties determine well performance in some extent, and this could not be controlled in fishbone operation. Output of the simulation determine suitable reservoir properties for fishbone operation. Parameters in reservoir properties include reservoir thickness and heterogeneity. Heterogeneity in reservoir is furtherly classified as vertical and horizontal heterogeneity (barrier).

Simulation suggests that fishbone is more effective in thicker reservoir in the equivalent reservoir volume. For a vertical well, thicker layer is more effective for fishbone stimulation compared to corresponding thinner layer and wider reservoir. Fishbone needles has a limitation in length, as it only could extend to 12 m. Therefore, wider reservoir with thinner layer has a disadvantage in fishbone operation, as fishbone needles are not capable to reach further rock body.

Fishbone performance decreases slightly in the presence of vertical barrier around fishbone annulus. This shows that fishbone lateral stimulation is not very effective in the presence of vertical barrier. This result is due to condition that fishbone needles do not connect reservoir in vertical direction effectively. On the other hand, fishbone performance has a minor effect in the presence of horizontal barrier. This result divulges that fishbone operation is not affected by horizontal barrier, as it will connect the reservoir horizontally. In other words, k_v/k_h value plays an important role to justify effectiveness of fishbone operation in reservoir. Smaller k_v/k_h value causes less effective fishbone operation compared to bigger k_v/k_h value in a single layer reservoir and vertical well.

6.3 Fishbone vs Conventional Fracturing

Performance increment in acid or hydraulic fracturing is usually quantified with skin factor. Fishbone and conventional fracturing performance is compared for selecting the best option for boosting well performance. Hydraulic/acid fracturing is modeled in BRILLIANT by creating an equivalent well bore radius after stimulation. Calculation results in the equivalent well bore radius of 0.40 m and 1.47 m for skin factor -1.05 and -2.35 respectively.

Conventional fracturing with skin factor -2.35 has a 47% higher cumulative production compared to fishbone stimulation. Simulation for gaining equivalent fishbone skin factor is also conducted. Simulation result shows that fishbone is equivalent with skin factor -1.05 for fishbone base case (Case A.1). Reason for this is that area created by fishbone annulus is still smaller compared to massive small conductive channels in hydraulic/acid fracturing. To achieve the same or more performance, two or more fishbones subs should be extended in a single reservoir layer.

6.4 Multi-Layered Reservoir in BRILLIANT

BRILLIANT is capable in simulating one layer reservoir with simulation runtime 3 hours for 90 days simulation, while two-layer reservoir simulation results in 6 hours for 90 days simulation. However, BRILLIANT is unsuccessful in simulating three layer reservoir. Three layer reservoir unsuccesful simulation shows that BRILLIANT is still incapable in handling a large number of cells.

CHAPTER 7

Conclusion

Conclusion for this master thesis are:

1. BRILLIANT and ECLIPSE comparison for a single open hole vertical well (Case A.0) results in a good match and BRILLIANT is considered valid for single phase reservoir simulation.

2. BRILLIANT and ECLIPSE comparison for fishbones case (Case A.1) results in 20% difference, that could be caused by different gridding size and dispersion model difference between ECLIPSE and BRILLIANT.

3. I could utilize BRILLIANT simulation result to be upscaled into ECLIPSE simulation as a permeability modifier or skin modifier. This upscaling is purposed to model ECLIPSE simulation accurately for fishbones stimulation. For Case A.1, permeability near well bore is modified into 18 mD to match BRILLIANT fishbone case.

4. Sensitivity analysis is done for controllable parameters, which directly related to fishbone geometry (fishbone operation itself), including number of needles, annulus diameter, and needles length. Fishbone needle increment from zero to one needle

has the biggest effect to increase well productivity, while fishbone annulus size has the smallest effect to increase well productivity.

5. Sensitivity analysis is done for uncontrollable parameters, which directly related to reservoir properties, including reservoir thickness and reservoir heterogeneity. Fishbone is more effective in thicker reservoir in the equivalent reservoir volume. Fishbone performance decreases slightly in the presence of vertical barrier around fishbone annulus. However, the performance is not affected by horizontal barrier, as fishbone will connect the reservoir horizontally.

6. Conventional fracturing with skin factor -2.35 has a 47% higher cumulative production compared to fishbone stimulation.

7. Simulation result shows that fishbone is equivalent with skin factor -1.05 for fishbone base case (Case A.0). It is then suggested to increase number of fishbone needles or sub to increase well performance.

8. BRILLIANT is capable in simulating one layer reservoir with simulation runtime 3 hours for 90 days simulation, while two layer reservoir simulation results in 6 hours for 90 days simulation, however BRILLIANT is unsuccessful in simulating three layer reservoir.

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Appendix A - ECLIPSE Code for Case A.0

```
-- ===========================================
-- LAURA MARIA PRISKILA
-- THESIS COMPARATION
-- ===========================================
RUNSPEC
-- ================================================

TITLE
COMPARATION BRILLIANT AND ECLIPSE (HOLE)

DIMENS
9 9 4 /

WATER

TABDIMS
1 1 15 15 1 15 /

WELLDIMS
2 200 1 2 /

LGR
-- LGRNO MAXNOCELLS
1 800 /

-- FRICTION
-- 1 /

START
1 'JAN' 2013 /

NSTACK
25 /

FMTOUT
FMTIN
UNIFOUT
```

```
UNIFIN

GRID
-- =============================================

DXV
200 100 60 60 60 60 60 100 200 /

DYV
200 100 60 60 60 60 60 100 200 /

DZ
81*5 81*5 81*5 81*5 /

PERMX
324*9.87 /

PERMY
324*9.87 /

PERMZ
324*9.87 /

PORO
324*0.4 /

EQUALS
'TOPS' 3535.0 1 9 1 9 1 1 /
/

CARFIN
-- NAME I1-I2 J1-J2 K1-K2 NX NY NZ
'LGR1' 5 5 5 5 1 4 5 5 4 /

HXFIN
16.25 12.5 1.5 12.5 16.25 /

HYFIN
16.25 12.5 1.5 12.5 16.25 /

HZFIN
5 5 5 5 /

ENDFIN
```

```
PROPS
-- ================================================

PVTW
-- PREF BW CW VW VISCOSIBILITY
1.014 1.0 3.8E-5 0.556 0 /

ROCK
-- PREF CR
1.014 0 /

DENSITY
-- OIL WATER GAS
722.2 997.35 1.12 /

PMAX
500 /

SOLUTION
-- ================================================

EQUIL
--DEP PRES DWOC PCWOC DGOC PCGOC RSVD RVVD FIPC
3537 380.0 3535 0.0 3100 0.0 1 0 0 /

RSVD
-- DEP RS
3535 250.77
3635 250.77 /

RPTSOL
1  11*0  /

SUMMARY
-- ================================================

FOPR
FGPR
FWPR
FOPT
FGPT
FWPT
FWCT
FOE
FGOR
```

```
LWBHP
'LGR1' 'PROD' /
/

LCPR
'LGR1' 'PROD' 3 2 2 /
/

FPR
FWIR
FWIT
RUNSUM

SCHEDULE
-- =============================================
TUNING
1  1  /
1.0 0.5 1.0E-6 /
/

NEXTSTEP
1 /
/

RPTSCHED
 1 1 1 1 1 0 2 1 2 0
 2 2 0 0 2 /

WELSPECL
-- NAME GROUP LGR I J DBH PHASE
'PROD' 'G' 'LGR1' 3 3 3538 'WATER' /
/

-- WELSPECS
-- NAME GROUP I J DBH PHASE
-- 'PROD' 'G' 3 5 1091 'OIL' /
-- /

COMPDATL
-- NAME LOCAL GRID I J K1 K2 OP/SH SATTAB CONFACT DIAM KH S D DIRN
'PROD' 'LGR1' 3 3 1 4 'OPEN' 2* 0.2 3* 'Z' / FISHBONES Z
/

-- COMPDAT
-- NAME I J K1 K2 OP/SH SATTAB CONFACT
```

```
-- 'PROD' 3 5 1 6 'OPEN' /
-- /

WCONPROD
-- NAME OP/SH CTLMODE ORAT WRAT GRAT LRAT RESV BHP
'PROD' 'OPEN' 'BHP' 5* 330 /
/

TSTEP
90*1 /
/
RPTSCHED
 1 1 1 1 1 0 2 1 2 0
 2 2 0 0 2 /

END
```

Appendix B - BRILLIANT Code for Case A.0

```
ADMIN FILE

#GRIDFILE geometry.brl
#SCENARIOFILE scenario.brl
#CAPTUREFILE  capture.brl
#GRAPHICFILE  Hole11

#MAXTIME 7776000 //s
#MAX_TIMESTEP 0.005 30 1 60 5 4800 20 86400 600//s 2 0.1 10 1.e5
#OUTPUT_FREQUENCE 86400 //s

#COURANT_NUMBER 1 //10 1e20

#TEST_TERMOPROP
#CHECK_AREA_ERROR true //false

GEOMETRY FILE

$BrilliantFormat 1

$MODEL PorosityFlow por.brl
#NAME Reservoir
#MATERIAL H2O 1.0
#PHASE_TYPE Liquid

$MODEL Dispersion disp.brl
#NAME Well
#MATERIAL H2O 1.0
#INITIAL_CONDITIONS Well_init
#PHASE_TYPE Liquid

@READFILE input.brl

#CURRENT_MODEL_AREA Reservoir
#SET_PART_NAME InvadedReservoir
#INITIAL_CONDITIONS Reservoir_init
```

```
#TRANSFORM %DISPLACE 0 0 =-layer1;
#CYLINDER_SQUER_SIZE 0.1
#CYLINDER_CENTER 1
#CYLINDER_PERIPHERY 8
#CYLINDER 5 1 nz o
well_id 0 well_leng 0 0
well_id 0 0 0
{//extension of the annulus
=-stim; =-stim; 0
=stim; =stim; 0
}
#TRANSFORM_END

#SET_PART_NAME OuterReservoir
#INITIAL_CONDITIONS Reservoir_init
#TRANSFORM
#BLOCK nx ny nz
=-resx; =-resx; =-layer1;
=-stim; =stim; 0
#BLOCK nx ny nz
=-stim; =-resx; =-layer1;
=resx; =-stim; 0
#BLOCK nx ny nz
=stim; =-stim; =-layer1;
=resx; =resx; 0
#BLOCK nx ny nz
=-resx; =stim; =-layer1;
=stim; =resx; 0
#TRANSFORM_END

#SET_PART_NAME BaseReservoir
#INITIAL_CONDITIONS Base_init
#TRANSFORM
#BLOCK 1 1 1
=-resx; =-resx; -20.1
=resx; =resx; =-layer1;
#TRANSFORM_END

#CURRENT_MODEL_AREA Well
#TRANSFORM %DISPLACE 0 0 =-layer1;
#CYLINDER_SQUER_SIZE 0.1
#CYLINDER_CENTER 1
#CYLINDER_PERIPHERY 8
#CYLINDER 1 2 40 i
well_id 0 well_leng 0 0
```

```
well_id 0 0 0
#TRANSFORM_END

$BOUNDARYCONDITIONS
#CURRENT_MODEL_AREA Well
#PRESSURE Pborehole
//Location of the boundary condition is in
the upper side of the well (last control volume)
=-well_id/2; =-well_id/2; =-layer1/40;
=well_id/2; =well_id/2; 0
```

SCENARIO FILE

```
Brl 1

@DEFINE
P_res_init 38000000 //Pa
T_res_init 323 //K
perm_init 9.87e-15 //m2
por_init 0.4
P_bhp 33000000 //Pa, very big because
the application always crash quickly
Pbase 38000000
permbase_init 9.87e-50 //m2
porbase_init 0.000001

#Reservoir_init
Temperature T_res_init
Pressure P_res_init
Darcy perm_init perm_init perm_init
Porosity por_init

#Well_init
Temperature T_res_init
Pressure P_res_init
Vx-velocity 0
Vy-velocity 0
Vz-velocity 0

#Pborehole
>Pressure P_res_init
0.5 P_bhp

#Base_init
Temperature T_res_init
```

```
Pressure Pbase
Darcy permbase_init permbase_init permbase_init
Porosity porbase_init porbase_init porbase_init

#Pbase
Pressure Pbase

POROSITY MODEL

/* File for parameter
modification to simulation model <PorosityFlow>.*/

#Radiation_include false
#Radiation_calc_frequence 1
#Radiation_beams_Azimuth 12
#Radiation_beams_Polar 4
#ThermoProp_model sw38_h2o
#Strength_include false
#Gravity_enabled true
#Gravity_direction 0 0 -1
#Apply_Pressure_Gradient true
#Allow_Phase_Change true
#Differencing_scheme UPWIND
#Artificial_viscosity 0
#Integration_period 1e+015
#Inactive_period 1e+015 // [sec]
The maximum time for a model to be inactive
#Inactive_criteria 0
// [Pa/sec] Criteria for
turning the model off.
 Has to differ from 0 to
turn on automatic inactivation
#Ignition_time 0
#SPLIT_CV false
#Flow_Inactive false
#MixedMultiphaseState false
#DensityBasedThermo false
#Ref_point_current_model 0 0 0 // a specified
 ref point within the geometry
#Ref_point_other_model 0 0 0 // a specified
 ref point within the geometry
#Reactivate_criteria -4.8367e-026
// [Pa] The maximum delta pressure you can accept in
 reference point 2 for an inactive model
#Output_interpolated_velocities false
```

```
 // Can reduce checkerboard spatial oscillations
#ContinueOnThermoCrash false
 // Continuing run with old state if ThermoProp fails
#TimeStepWhenActivated -1
// The initial time step when the model becomes active
#Split_debounce_steps 5
#Join_concentration_difference 0.05
#Split_concentration_difference 0.1
#Split_concentration_material C1
#Split_minimum_volume 0.001
#Join_maximal_volume 0.03
#Nonlinear_strength true

#Relaxation_factor
/* Variable-name   Relaxation-factor   Active
   (Information)       (Modify)       (Modify) */
Pressure                  1             true
Enthalpy                  1             true
Density                   0.1           false
EddyViscosity             0.3           false
H2O                       1             false

#Store_results
/* Variable-name       Store      Variable-type
   (Information)      (Modify)    (Information) */
Vx-velocity             true      Dependent variable
Vy-velocity             true      Dependent variable
Vz-velocity             true      Dependent variable
Vx-velocity_(interpolated) false     Dependent variable
Vy-velocity_(interpolated) false     Dependent variable
Vz-velocity_(interpolated) false     Dependent variable
Pressure                true         Solved variable
PressureCorrection      true      Dependent variable
EddyDisipation          false     Dependent variable
KineticEnergy           false     Dependent variable
Enthalpy                false        Solved variable
Temperature             true      Dependent variable
Density                 true      Dependent variable
EddyViscosity           false     Dependent variable
DisipationTerm          false     Dependent variable
HeatTransferCoef        false     Dependent variable
ConvHeat                false     Dependent variable
DiKi                    false     Dependent variable
FlowFlux                false     Dependent variable
Viscosity               false     Dependent variable
```

```
Static_temperature      false     Dependent variable
Stagnation_pressure     false     Dependent variable
MixLength               false     Dependent variable
WallFunk                false     Dependent variable
ContinuityError         false     Dependent variable
ValveReleaseRate        false     Dependent variable
ValveInletRate          false     Dependent variable
VaporVFr                false     Dependent variable
SolidVFr                false     Dependent variable
Absorption              false     Dependent variable
Emissivity              false     Dependent variable
RadSinkSource           false     Dependent variable
NetRadiation            false     Dependent variable
EmittedRadiation        false     Dependent variable
ExposedRadiation        false     Dependent variable
H2O                     true         Solved variable
```

```
DISPERSION MODEL

/* File for parameter modification to
simulation model <Dispersion>.*/

#Radiation_include false
#Radiation_calc_frequence 1
#Radiation_beams_Azimuth 12
#Radiation_beams_Polar 4
#ThermoProp_model sw38_h2o
#Strength_include false
#Gravity_enabled true
#Gravity_direction 0 0 -1
#Apply_Pressure_Gradient true
#Allow_Phase_Change true
#Differencing_scheme UPWIND
#Artificial_viscosity 0
#Integration_period 1e+015
#Inactive_period 9e+007
// [sec] The maximum time for a model to be inactive
#Inactive_criteria 1000
// [Pa/sec] Criteria for turning the model off. Has to differ
from 0 to turn on automatic inactivation
#Ignition_time 0
#SPLIT_CV false
#Flow_Inactive false
#MixedMultiphaseState false
#DensityBasedThermo false
```

```
#Ref_point_current_model 0 0 0
// a specified ref point within the geometry
#Ref_point_other_model -0.039 0.119 -10.524
// a specified ref point within the geometry
#Reactivate_criteria 200000
// [Pa] The maximum delta pressure you can accept
in reference point 2 for an inactive model
#Output_interpolated_velocities false
// Can reduce checkerboard spatial oscillations
#ContinueOnThermoCrash false
 // Continuing run with old state if ThermoProp fails
#TimeStepWhenActivated -1
// The initial time step when the model becomes active
#Split_debounce_steps 5
#Join_concentration_difference 0.05
#Split_concentration_difference 0.1
#Split_concentration_material C1
#Split_minimum_volume 0.001
#Join_maximal_volume 0.03

#Relaxation_factor
/* Variable-name   Relaxation-factor   Active
   (Information)       (Modify)       (Modify) */
Vx-velocity               0.7           true
Vy-velocity               0.7           true
Vz-velocity               0.7           true
PressureCorrection        0.3           true
EddyDisipation            0.8           true
KineticEnergy             0.8           true
Enthalpy                  1             true
Density                   0.1           false
EddyViscosity             0.3           false
H2O                       1             false

#Store_results
/* Variable-name       Store      Variable-type
   (Information)      (Modify)    (Information) */
Vx-velocity             true         Solved variable
Vy-velocity             true         Solved variable
Vz-velocity             true         Solved variable
Vx-velocity_(interpolated) false     Dependent variable
Vy-velocity_(interpolated) false     Dependent variable
Vz-velocity_(interpolated) false     Dependent variable
Pressure                true      Dependent variable
PressureCorrection      true         Solved variable
```

```
EddyDisipation          false       Solved variable
KineticEnergy           false       Solved variable
Enthalpy                true        Solved variable
Temperature             true     Dependent variable
Density                 true     Dependent variable
EddyViscosity           false    Dependent variable
DisipationTerm          false    Dependent variable
HeatTransferCoef        false    Dependent variable
ConvHeat                false    Dependent variable
DiKi                    false    Dependent variable
FlowFlux                true     Dependent variable
Viscosity               true     Dependent variable
Static_temperature      false    Dependent variable
Stagnation_pressure     false    Dependent variable
MixLength               false    Dependent variable
WallFunk                false    Dependent variable
ContinuityError         false    Dependent variable
ValveReleaseRate        false    Dependent variable
ValveInletRate          false    Dependent variable
VaporVFr                false    Dependent variable
SolidVFr                false    Dependent variable
Absorption              false    Dependent variable
Emissivity              false    Dependent variable
RadSinkSource           false    Dependent variable
NetRadiation            false    Dependent variable
EmittedRadiation        false    Dependent variable
ExposedRadiation        false    Dependent variable
H2O                     true        Solved variable

.
```

Appendix C - ECLIPSE LGR Optimization

Guideline for grid refinement in X and Y direction is having maximum grid size less than or equal of fishbones length needles. By doing this, fishbones small geometry can be captured. However, unnecessary refined grid could increase running time and enlarge the file size. Pressure profile near the wellbore could be a good parameter to assess the quality of refinement. Optimization should be done in choosing suitable size of grid blocks near wellbore and fishbones needle. The idea is to refine grid blocks size to a value so that pressure profile as a function of distance does not change anymore. In total, four cases are run to find optimum grid block size in X, Y, and Z direction. ECLIPSE simulation is done for Base Case A.0, Case F.1, Case F.2, and Case F.3. Description for each case is presented in picture and table below.

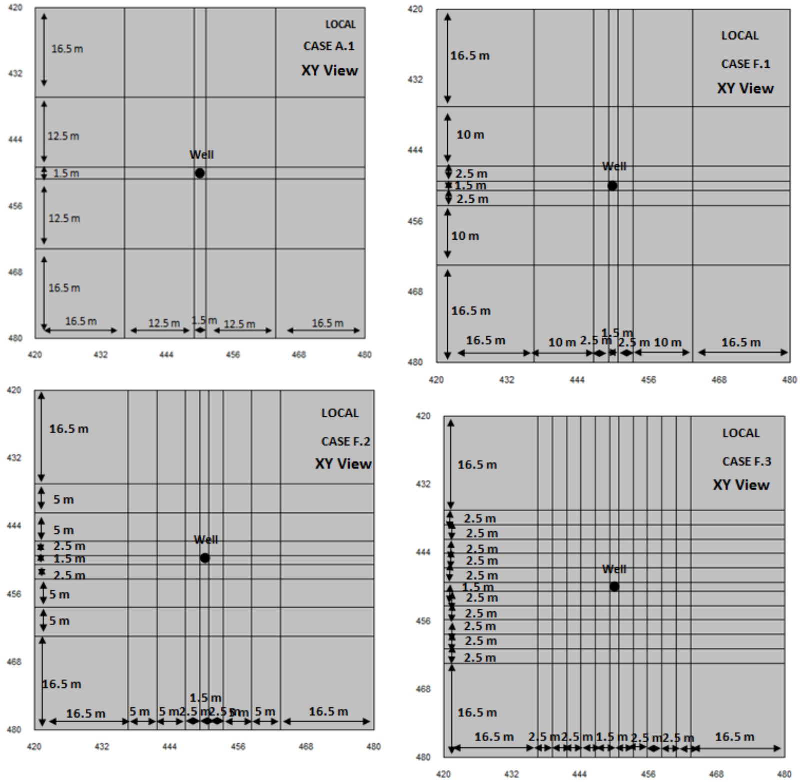

Figure 7.1: ECLIPSE LGR Optimization Case

Table 7.1: Local Grid Blocks Number in All Case

No.	Case	LGR Grid Blocks
1	Base Case A.0	100
2	Case F.1	196
3	Case F.2	324
4	Case F.3	676

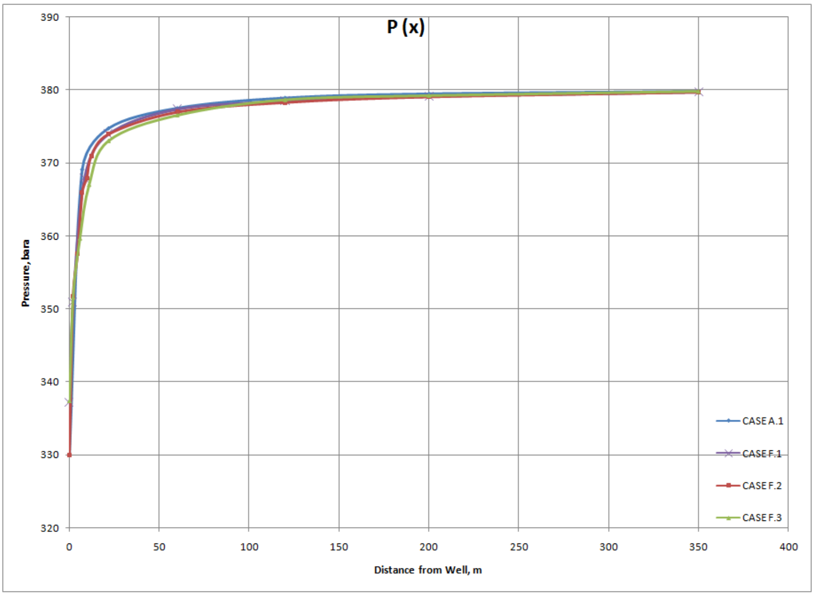

Figure 7.2: ECLIPSE Pressure Distance Profile in X Direction DAY 1

Result shows that grid blocks coarsening and refining does not make a lot of difference in pressure profile. This makes further grid refinement is not necessary. Base Case A.0 with 100 grid blocks is good enough to create a fishbone simulation.

Appendix D - Compressibility Calculation in BRILLIANT

Compressibility calculation is inputted in BRILLIANT automatically by inputting the fluid package. Since the fluid package for CASE A.0 is water, compressibility is calculated by density change as a function of pressure (constant temperature), by the formula,

$$c_f = \frac{1}{\rho}(\frac{\delta(1/\rho)}{\delta P}) \tag{7.1}$$

with c_f is fluid compressibility, ρ is density, and P is pressure. BRILLIANT density as a function of pressure is presented in picture below,

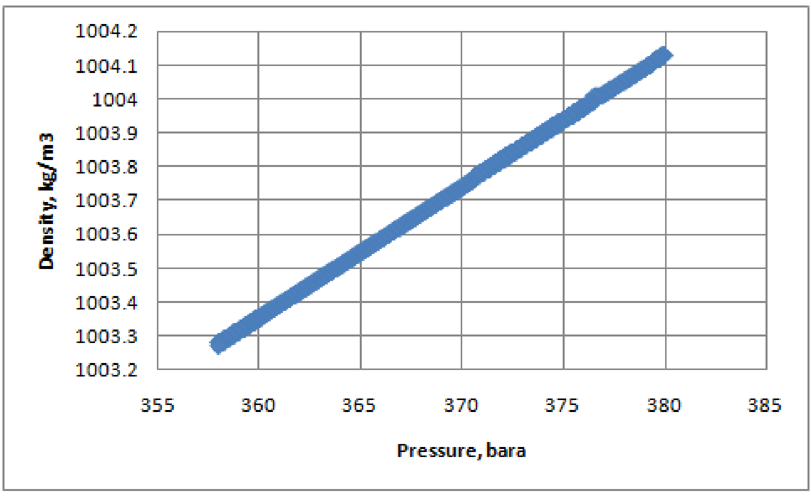

Figure 7.3: Density as a function of Pressure

After calculation with **Equation 6.1**, I obtain constant compressibility value of 3.87E-5 1/bar. Result of the calculation will be inputted to ECLIPSE simulation Case A.0 in order to obtain the same compressibility value.