Simulation and Scale-up Studies of Reservoir-analog Models from Miocene Carbonate Outcrops in Southeast Spain

By

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Abstract

The La Molata and Agua Amarga outcrops in Southeast Spain provide an unparalleled opportunity to study very fine-scale carbonate exposures which can be used as analogs to some deep and shallow-water carbonate systems around the world. On one hand, two carbonate units in La Molata (TCC and DS3) are examined through engineering designs to gain a better understanding of fluid flows in the system and what is the optimal scenario to recover the most from similarly heterogeneous carbonate reservoirs. Terminal Carbonate Complex (TCC) simulation results show that production well on the updip side of the model is more effective than when it is on the lower ground, the impact of sequence boundaries on recovery is limited, full completion is not required to improve production, and 5-spot patterns recover better than 9-spot patterns. Findings on Reefal Platform System (DS3) indicate that oil is trapped in the facies associated with low permeability, Scatter permeability has little effect on recovery of the system, and vertical wells with added laterals will recover more in the presence of erosion surfaces. On the other hand, the Agua Amarga project scales up previously built facies and examines the resulting connected volumes in comparison to the initial volumes. What it finds is that reservoir volumes will break down, reduce in size or be lost rather than combining into one large volume. This project answers the question whether the volumes will all merge into one and shows that facies scale-up is not a good practice for building the simulation model.

Acknowledgement

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Greg Benson from ExxonMobil spent the time and effort to build the detailed geologic grids and static properties of La Molata and I acknowledge his work. I am also thankful for Mark Ballard who worked hard to setup the workstation and server systems in support of this project.

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To my wife Linh Phan for her continuous support and encouragement throughout my studies,

And the rest of the Nguyen's family I have been so blessed to be born into and grow up with

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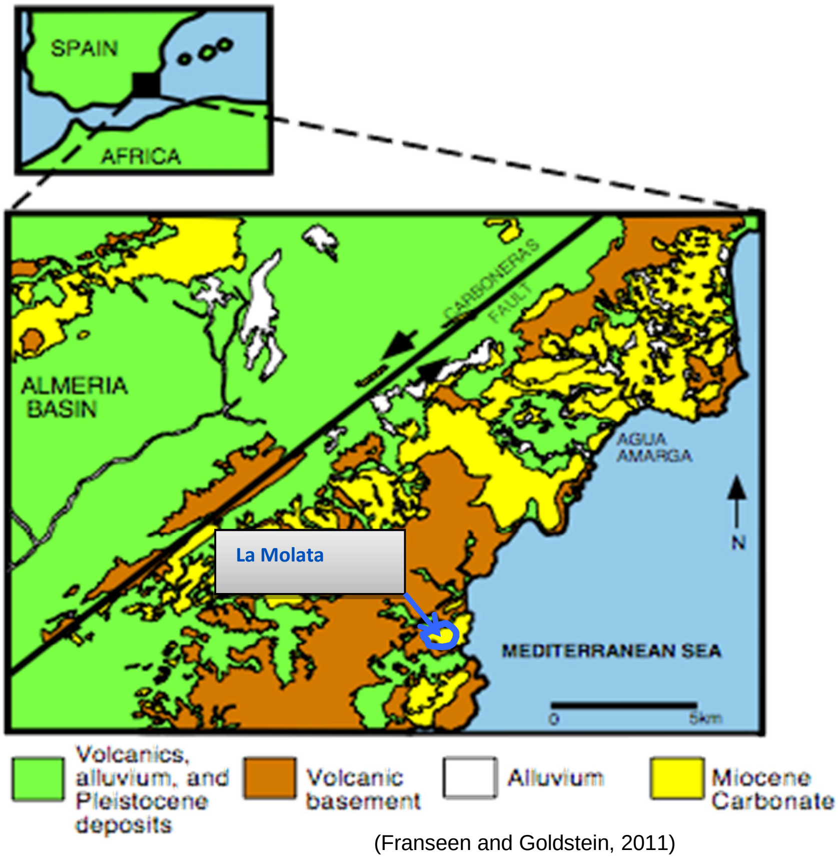
Chapter 1: Overview of Outcrop Models

Introduction

This chapter is aimed to provide the background of two reservoir-analog model projects based on Southeast Spain outcrops. The first project, La Molata model, explores various diagenetic scenarios and engineering designs to experiment them with development schemes for hydrocarbon recovery processes. The second project, Agua Amarga model, performs a scale-up study for facies and their connected volumes and examines their connectivity afterwards. These two projects are different areas of outcrop study in Southeast Spain.

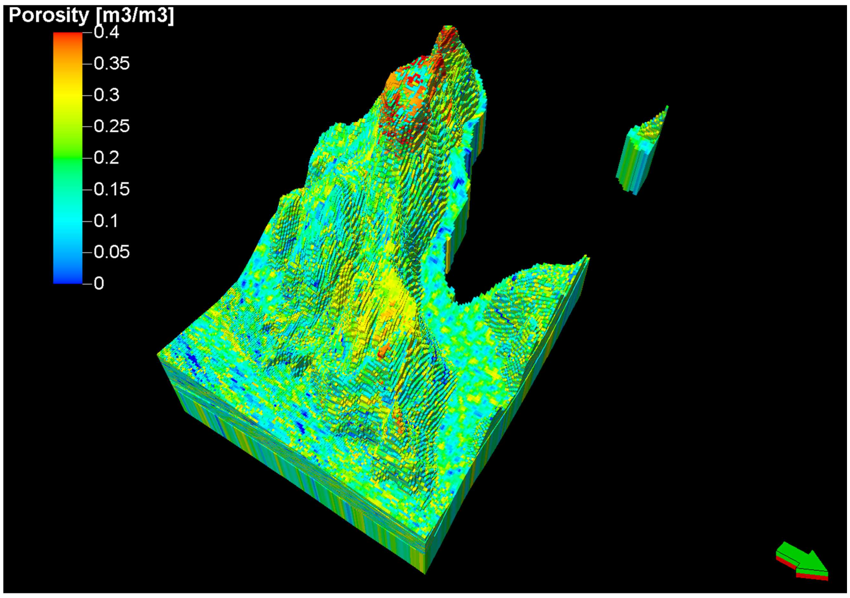
1.1. La Molata Overview

The La Molata field provides an excellent opportunity to study outcrop exposures in the coastal areas of Southeast Spain (Figure 1-1). Extensive field work, data collection and integration have been done by geologists from the University of Kansas and ExxonMobil in an industry-academic consortium to create a 3D reservoir analog model in Petrel. This thesis will discuss the flow simulation work that follows reservoir characterization and static model construction in order to answer some of the questions being asked, mainly 'what if' it was a subsurface reservoir. La Molata is made up of the following four distinct units including TCC, DS3, DS2 and DS1 that have been characterized by Goldstein *et al.*, 2011

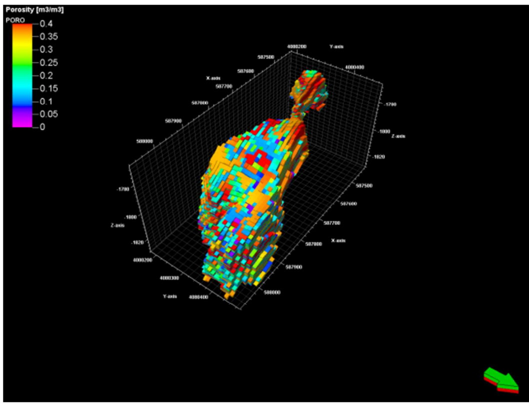


(Franseen and Goldstein, 2011)

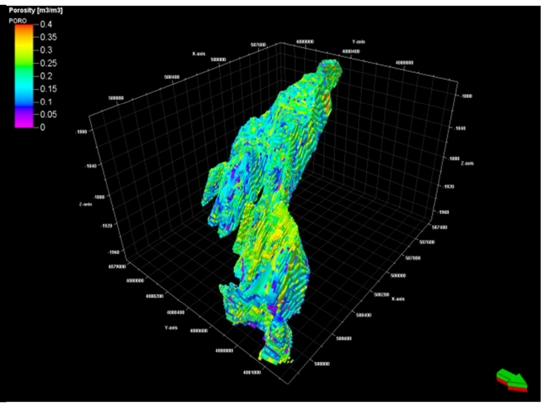
Figure 1-1: The La Molata Field Location and Regional Geology



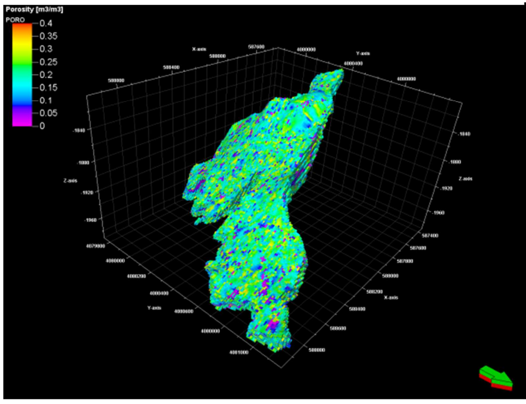
(a) La Molata



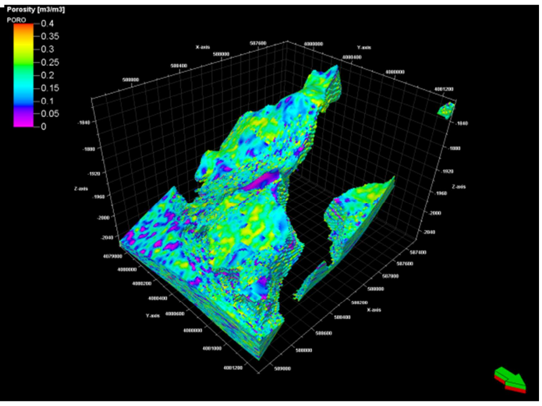
(b) TCC



(c) DS3



(c) DS2



(e) DS1

Figure 1-2: Porosity of La Molata and the four separate units TCC, DS3, DS2 and DS1

The Heterozoan System (DS1A, DS1B) is an analog to ancient heterozoan reservoir systems including Perla giant gas field, Mississippian reservoirs in the Midcontinent USA, and new discoveries in Southeast Asia. DS1 consists of stratigraphic units that onlap against sloping topography on volcanic basement. Each of the stratigraphic units includes a fining upward cycle. The base of each cycle is dominated by bioclastic packstones with potential reservoir porosity (Franseen et al. 2011).

The Reef Complex System (DS2, DS3) in Figure 1-2c and 1-2d is an analog for ancient carbonate-rimmed basins with or without basinal evaporites. It is a direct analog for important Miocene reservoirs such as those in the Middle East, Southeast Asia, Central and South America. DS3 consists of aggrading and prograding reef and forereef slope wedges that alternate with other facies including volcaniclastic conglomerates. These reef and forereef systems can be evaluated as primary reservoir targets. DS2 (Figure 1-2c) consists of two stratigraphic units of breccia associated with grainy carbonate facies. The two units are highly heterogeneous in nature and separated by chalky carbonates with lower permeability (Franseen et al. 2011).

The Terminal Carbonate Complex (TCC) in Figure 1-2b is an analog to oolite and microbialite reservoirs worldwide, including the Jurassic in the Middle East and USA, the Mississippian in the USA, and Cretaceous of offshore Brazil. TCC consists of four sequences that alternate between oolite and microbialite (Lipinski 2009).

1.2. Agua Amarga Overview

Agua Amarga basin in SE Spain provides excellent detailed outcrop exposures for reservoir-analog study of deepwater carbonate depositional environments. Previous work done by Dvoretsky *et al.* placed an emphasis on part of the basin stratigraphy which includes "sediment gravity flow deposits interstratified with fine-grained hemipelagic-pelagic deposits". This is an unique opportunity to examine fine scale field observation which most subsurface reservoir models fail to attain due to a lack of data acquisition. In addition, research in modeling of outcrop reservoirs will provide a case study of static grid coarsening and recovery mechanisms in new carbonate field exploration.

Field data acquisition and interpretation were done in previous study by Dvoretsky *et al.* 2012. Among their most significant findings are focused-flow and dispersed-flow systems that lead to very distinct reservoir properties. While the former tends to have sediment-gravity flows funnel from a broader platform into a narrow channel generating high reservoir-to-baffle facies ratios, the latter features flows from "a short linear dimension of carbonate platform margin" (Dvoretsky *et al.* 2012) and subsequently accumulates high baffle volumes and lower amounts of reservoir facies (Figure 1-3).

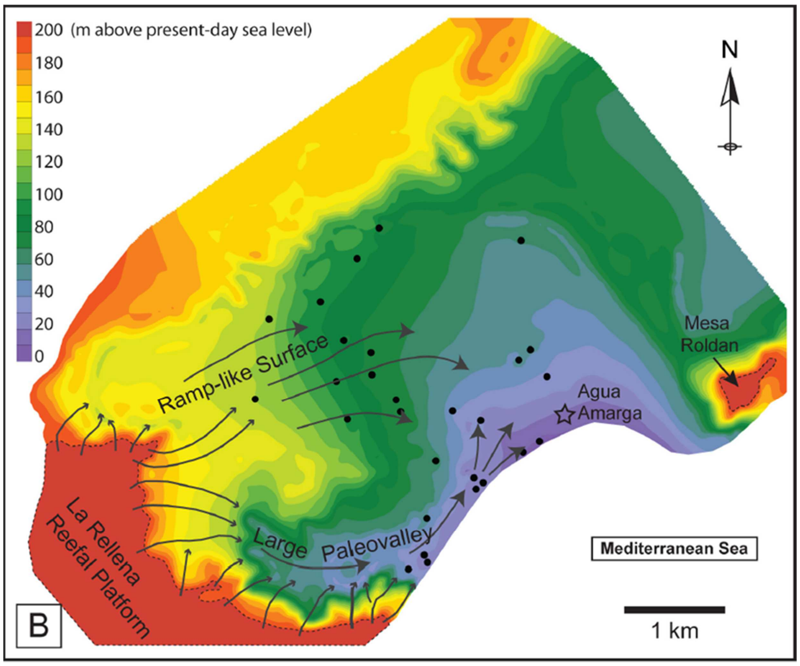


Figure 1-3: Focused-flow and Dispersed-flow Systems (Goldstein *et al.* 2012)

On top of collecting all the measured sections, photomosaics and core plugs and integrating them into Petra, construction of the 3D Petrel model was carried out by Dvoretsky *et al.* which consists of facies property and connected volumes. "The connected volume property was used to query the facies model to better understand the distribution of connected geomodel cells with the same facies or group of facies" (Dvoretsky *et al.* 2012). The goal of this study is to investigate the effect of conventional scale up methods on retaining the geology features and development of static reservoir model.

Chapter 2: La Molata Simulation Study

Introduction

This chapter covers the work done in La Molata project, mainly in two units: TCC and DS3. These units are experimented with diagentic scenarios and various engineering designs to learn more about the hydrocarbon recovery processes in these carbonate systems. Questions for each unit are also addressed in this chapter regarding what would be the optimal way to produce out of the reservoir-analog models. DS2 and DS1 units are briefly examined with vertical well patterns to provide a preliminary assessment of recovery in these systems.

2.1. Simulation Models

The static mega-model La Molata poses a challenge to flow simulation as it contains more than 80 million grid blocks with a lateral 10x10(m) resolution. Not only will this make simulation computationally expensive, even impossible, but also extremely difficult to converge to a reliable result. Therefore it has given rise to the need of building individual simulation grids that allow the study of each separate unit. Also since this is a reservoir-analog study, each unit is assumed to be submerged 2000m from where it is to represents a subsurface black oil formation. The process of building simulation grids for each unit involves initializing a simulation case where (1) unimportant cells are made inactive (those that can cause convergence problems like having a negative porosity or are not supposed to be in the model when it was created) and (2) the entire unit is shifted downward 2000m to be a reservoir analog. Then the grid exported from this initialization is loaded back into the project and only porosity and permeability are included as reservoir properties.

Using this approach La Molata model was split up into 4 units (TCC, DS3, DS2 and DS1) with a significantly lower amount of grid cells vital to simulation study of each unit. Figure 1-2 displays the initial geologic facies model with filters that hide redundant cells versus the simulation grid porosity after pre-processing without the redundant cells, since only porosity and permeability can be the output for initialization. In addition to that, the amount of grid cells for each model is presented in Table 2-1 to demonstrate how much the model has been downsized. This plays a significant role in simulation because a mega model with 85 million cells can be computationally challenging. From Table 2-1 TCC has less than 300 times the number of active cells its initial model had, which saves computation time running on simulations. On the other hand, DS3 is more than 100 times smaller and this has tremendously helped with computation resources as DS3 is the largest unit in La Molata. Similarly, DS2 and DS1 are about 10 times less of what they were at the beginning. As the grids are properly prepared, fluid and rock models specified by ExxonMobil are implemented in this study.

Units	Geologic Model (Cells)	Reservoir Model (Cells)	Reduction (Times)
TCC	10,330,400	32,780	315.1
DS3	65,564,000	502,088	130.6
DS2	3,552,000	337,469	10.5
DS1	5,712,800	739,427	7.7

Table 2-1: Number of cells in La Molata Model Before and After pre-processing

2.1.1. Rock & Fluid Properties

Guidance from ExxonMobil suggested the project starts with simplicity first and adds complexity later. For example, a single set of displacement properties may be used at the beginning and then multiple properties will be assigned based on grouping when a better understanding of the flow behaviors is obtained.

2.1.1.1. Diagenetic Scenarios

In order to understand the petrophysical properties of this model, it is important to take into consideration the diagenetic processes affecting porosity and permeability. From Benson *et al.* (2014), major diagenetic products include dolomitization and meteoric calcite cementation which are measured both in the field and laboratory and used to derive porosity-permeability scenarios. Based on the previous study, dolomitization would increase porosity and permeability while calcite cementation generally reduced porosity and permeability. La Molata modeling effort is part of a larger industry-academic alliance where several academic institutions construct outcrop geological models in the SE Spain areas. However porosity and permeability measurements of La Molata significantly differ from those of other outcrops and therefore to make useful comparison of simulation results among many outcrop-based models, it is vital to standardize porosity and permeability values assigned to each model within the consortium. The purpose is to help flow simulation focus mainly on the effects of stratigraphic architecture, sedimentary fabrics and patterns of early diagenesis (Benson *et al.* 2014).

Among the institutions that participated in the consortium with ExxonMobil, a consistent rock property calculation scheme called Standard Property Calculator was developed and used, where the initial geologic models include only compaction and pre-burial diagenetic effects that universally occur and later diagenetic effects were overlain on the initial properties as “Scenarios” that was varied for evaluation of impact on fluid flow (Benson *et al.* 2010). The scenarios applied in this study are summarized in Table 2-2. The porosity and permeability were estimated by standard property calculator with various scenarios. The original scenario assumes a system containing original depositional mineralogy and buried under 2000 meter subsurface. The dolomite scenario assumes 100% replacement of calcite with dolomite. The original plus calcite cement scenario imposes porosity and permeability degradation as a function of cell location within defined intervals. The dolomite plus calcite cement scenario imposes porosity and permeability degradation as a function of cell location within the defined cementation intervals. The variable dolomite scenario, likely a most representative of subsurface reservoir scenario, imposes weight average of two previous scenarios using grain fraction dolomite and grain fraction calcite as defined by contour maps. The rank transformed variable dolomite scenario uses rank transform of variable dolomite scenario porosity with the core plug porosity-permeability transform and scatter, which preserves diagenetic patterns while honoring core plug poro-perm statistics.

Scenario	Assumptions
Original	Original depositional mineralogy and 2000 meter burial
Dolomite	100% replacement of calcite with dolomite and 2000 meter burial
Original plus calcite cement	Imposes porosity and permeability degradation as a function of cell location within defined intervals
Dolomite plus calcite cement	Imposes porosity and permeability degradation as a function of cell location within the defined cementation intervals
Variable Dolomite	Weight average of previous two scenarios using grain fraction dolomite and grain fraction calcite as defined by contour maps. (most representative of subsurface reservoir)
Rank Transformed	Uses Rank Transform of Variable Dolomite scenario porosity, then uses the core plug porosity-permeability transform and scatter. (Preserves diagenetic patterns while honoring core plug Poro-Perm statistics)

Table 2-2: Porosity and Permeability Scenarios for La Molata model

The porosity and permeability modeling workflows employed by ExxonMobil and KU geologists also involve creating permeability with scatter properties in addition to the regular permeability without scatter. This is done through transforming the porosity into $\log_{10}$Perm (with scatter) and then populating $\log_{10}$Perm (no scatter) using property calculator.

The result is permeability with and without scatter property for each of the six diagenetic scenarios. Figure 2-1 depicts the result of scatter being incorporated into porosity-permeability relationships to give a more realistic permeability variation. Porosity-Permeability regressions in Figure 2-2 project the central tendency of permeability but it is also important to include the random noise typically observed in reality.

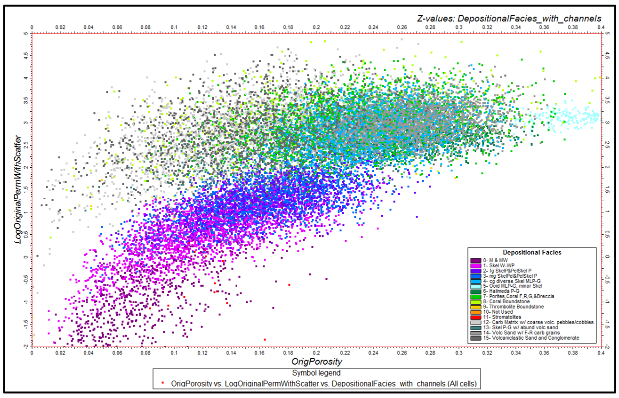


Figure 2-1: Log10Perm versus Porosity Transform (Scatter)

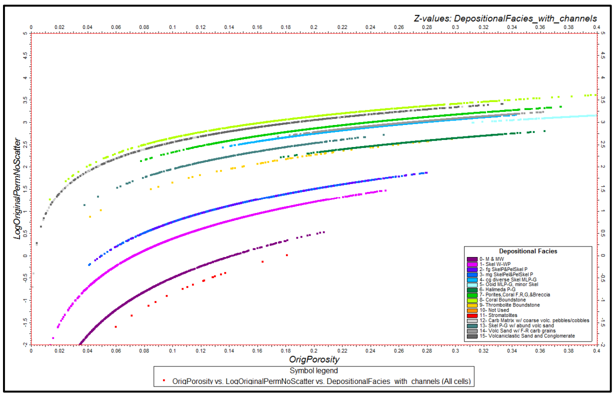


Figure 2-2: Log10Perm versus Porosity Transform (No Scatter)

2.1.1.2. Black Oil Model

A black oil fluid model is implemented in this study for water flooding simulation. Oil and water properties include viscosities and densities which are defined based on mobility ratios of the displacing phase and the fluid being displaced. The reservoir model is assumed to have no gas cap with reservoir pressure at 3000psia and bubble point pressure at 2200psia. The reservoir temperature is 250^{o}F and uniform rock compressibility is assumed to be 5 x 10^{-6}psi. Based on the guideline proposed by ExxonMobil Upstream Research Company (EMURC), the fluid properties are defined and summarized in Table 2-3. The proposed oil viscosity is either 0.52cp or 4 cp, water viscosity is 0.36 cp, oil and water density is 0.85 and 0.95gm/cc respectively. As a result, the mobility ratio between water and oil becomes 0.94 for the favorable case and 7.2 for unfavorable fluid mobility (Assuming Krw = 0.65 at Sw = 0.1 and Kro = 1.0 at Sw = 0.85). Mobility ratios are derived using $M=(K_{rw}/\mu_w)/(K_{ro}/\mu_o)$

	Fluid Mobility		Units
	Favorable	Unfavorable	
	M<1	M>1	
Oil Viscosity (μ_o)	0.52	4	cp
Oil Density	0.85	0.85	g/cm3
Water Viscosity (μ_w)	0.36	0.36	cp
Water Density	0.95	0.95	g/cm3

Table 2-3: Input Parameters of Favorable and Unfavorable Fluid Mobility Ratios.

2.1.1.3. Relative Permeability and Capillary Pressure

Relative permeability and capillary pressure curves derived from EMURC proposed approach are used for initialization of fluid distribution and flow calculation during the fluid production. In addition to drainage relative permeability and capillary curve, three sets of imbibition relative permeability and associated capillary curves are used for description of multiphase flow in each cell, where each set of curves represents multiphase flow in cells with permeability of value ranging from less than 10mD, between 10 and 100mD and above 100mD.

2.1.1.3.1. Drainage Process

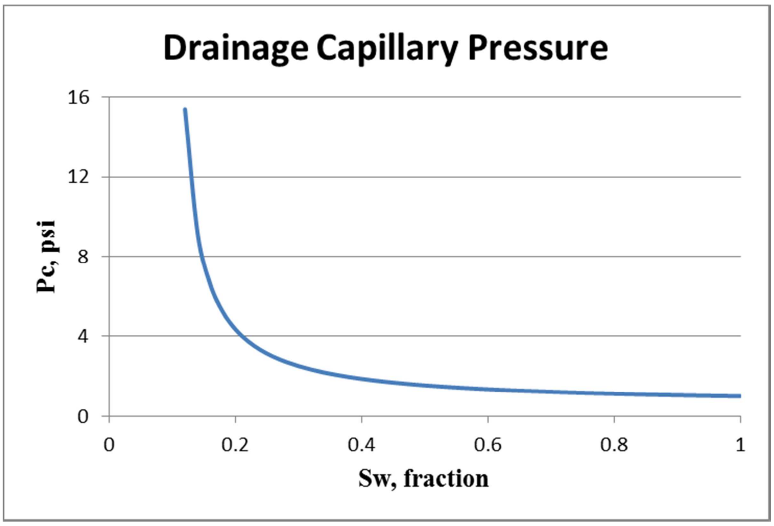


Figure 2-3: Drainage Capillary Pressure

Capillary pressure:

$$Pc = Pc_{th} + \left(\frac{1-S_{wn}}{1+aS_{wn}}\right)(P_{max} - P_{cth}) \qquad (2\text{-}1)$$

Where:

- "a" is a shape factor related to permeability and is 120
- P_{cth} is threshold capillary pressure P_{cth} = 1.0psia and P_{max} = 55psia
- S_{wn} is normalized water saturation: $S_{wn} = (S_w-S_{wir})/(1-S_{wir})$ with S_{wir} = 0.1

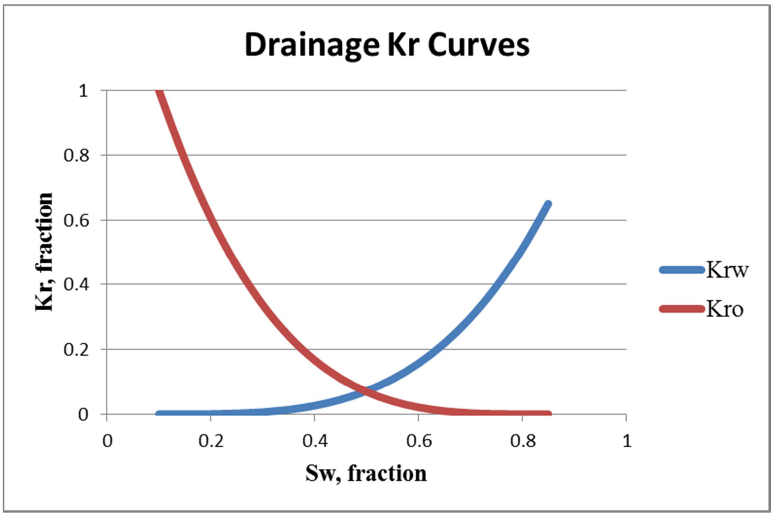


Figure 2-4: Drainage Relative Permeability

Corey Equations are used to define relative permeability

$$k_{rw} = k_{rwro}(\frac{S_w - S_{wi}}{1 - S_{wi} - S_{orw}})^m \quad (2\text{-}2)$$

$$k_{ro} = (\frac{1 - S_w - S_{orw}}{1 - S_{wi} - S_{orw}})^n \quad (2\text{-}3)$$

Which:

- Oil corey (m) = 3.5
- Water corey (n) = 3.5
- K_{rwro} = 0.65
- S_{wi} = 0.1
- S_{orw} = 0.15

2.1.1.3.2. Imbibition Process

Capillary pressure:

$$P_c = Pc_{cross} + \frac{a}{\tan(S_{wn} * \pi)} \quad (2\text{-}4)$$

Where:

- $S_{wn} = (S_w - S_{wir})/(1-S_{wir})$ with $S_{wir} = 0.1$
- $Pc_{(cross)} = -1$ (psi)
- a = 2 and $S_{orw} = 0.15$

To increase complexity and test multiple relative permeability scenarios at a time, three ranges of permeability consisting of low (less than 100mD), moderate (10 to 100mD) and high (higher than 100mD) values are defined. Three sets of imbibition relative permeability based on the above permeability range are determined from the Corey equations (2-2) and (2-3) earlier using the parameters shown in Table 2-4 as well as the drainage curve calculation.

	Drainage	K =< 10 mD	K = 10-100 mD	K >= 100mD
Corey Oil (m)	2	3	3.5	4
Corey Water (n)	7	4	3.5	3
krw max	1.0	0.5	0.65	0.75
Swir	0.1	0.2	0.1	0.08
Sorw	0.0	0.2	0.15	0.12

Table 2-4: Input Parameters for Relative Permeability Corey Equations

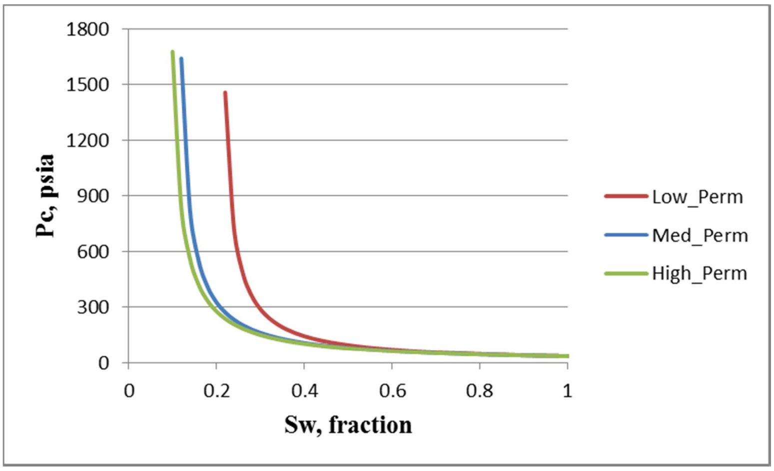


Figure 2-5: Imbibition Capillary Pressure

These curves are assigned during displacement to examine flow behavior and recovery efficiency among different scienarios. Similarly three capillary pressure curves associated with relative permeability curves based on permeability range are derived from the capillary pressure equation (2-4) using parameters from Table 2-5.

	K =< 10 mD	K = 10-100 mD	K >= 100mD
$Pc_{(cross)}$ (psi)	-1	-1	-1
a	2	2	2
Swi	0.2	0.1	0.08
Sorw	0.2	0.15	0.12

Table 2-5: Input Parameters for Imbibition Capillary Pressure

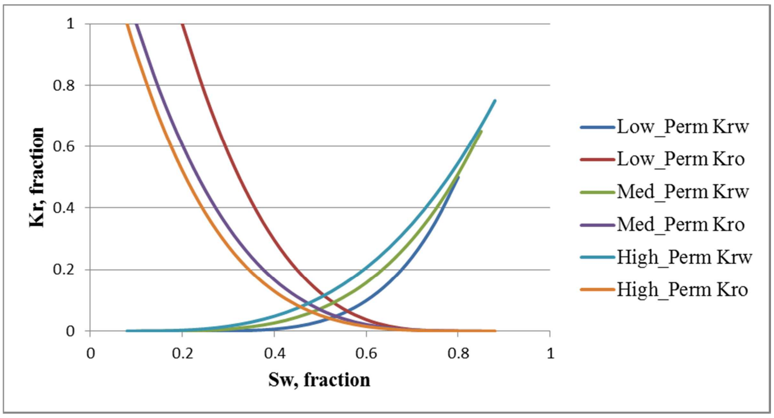


Figure 2-6: Imbibition Relative Permeability

2.1.2. Study Objectives

There are three major objectives for this research project which include:

(1) Construct reservoir model from La Molata reservoir analog model

(2) Conduct reservoir simulation with experimental engineering design

(3) Test hypotheses for each reservoir system and investigate effect of reservoir type (heterozoan, breccia, reefal platform, oolite-microbialite) on the hydrocarbon recovery process

More specific questions have been asked for each unit of La Molata and they are mainly concerned with what would be the optimal well design to recover most from certain carbonate systems. These following are questions to target each unit in examining the effect of reservoir heterogeneity on the recovery process.

TCC: What would be the effect of sequence boundaries in producing the reservoir from the uppermost cycle in the most updip position?

DS3: For the reefal platform system, how efficient would a vertical well drilled up-dip be able to drain the reservoir? How much oil would be left behind because of progradation and lateral pinchouts of reefs? Would a horizontal well be required and should it be along strike (to intersect the along strike discontinuity of reef wedges) or down-dip to intersect the maximum number of progrades?

DS2: Given the heterogeneity of the Megabreccia reservoir system, is it a reservoir? Is vertical or horizontal well required? Would the horizontal well be drilled downdip or along strike?

DS1: Given the nature of onlapping heterozoan cycles, will a vertical well drilled into the proximal point of onlap effectively produce the entire section? Should a well be drilled on downslope? What is the best strategy to place injectors and producers along with the depth of injection during a waterflood practice?

In addition, upscaling is also applied on initial TCC and DS3 grid systems. Through lateral and vertical coarsening, multiple algorithms and sampling methods are tested to preserve pore volume and replicate displacement processes from the initial model. The goal is to come up with a workflow for reservoir engineers to upscale the model as needed.

2.2. Terminal Carbonate Complex (TCC)

This section discusses the simulation work that has been done on the uppermost Terminal Carbonate Complex unit of La Molata model. This includes:

- Experiment different rock and fluid properties to correlate with geologic scenarios

- Scale-up the fine grid blocks for less computational resources in flow simulation

As the smallest and least complex unit of the four (TCC, DS3, DS2, DS1), TCC is a simple reservoir analog model as a startup for testing in answering the question:” How would sequence boundaries affect producing the reservoir from the uppermost cycle in the most up-dip position?” and then exploring grid coarsening methods to answer what would be a good practice to build simulation grid cells while retaining reservoir heterogeneity.

2.2.1. Engineering Design

The simulations start with TCC unit consisting of original porosity and permeability with no scatter, favorable fluid mobility ratio (M<1), one single set of relative permeability and capillary pressure curves for drainage process derived from Equations (2-1), (2-2) and (2-3), rock compaction from correlation, and development strategy with a producer on the down-dip side and injector on the up-dip (Figure 2-7). This is considered the base case though sometimes a “base case” may only mean original porosity and permeability with no scatter. There is also a reverse version where injection comes from down-dip to up-dip later on when the effect of producer locations is considered. Furthermore, flow simulation is carried out in a period of 5 years for most cases. Report steps are set up on a one-month basis within the first 3 years. After that simulation will output the results every 6 months (twice a year).

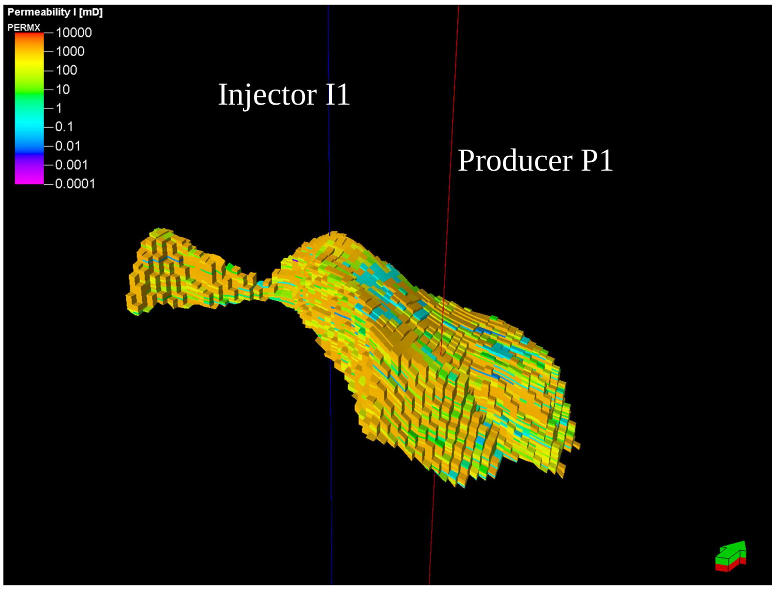


Figure 2-7: Well Locations for the Base Case

2.2.1.1. Simulation Input

This part of study experiments the impact of each individual set of input parameters: porosity and permeability, fluid mobility ratios, relative permeability and capillary pressure. The configurations and assumptions made in this research are in line with ExxonMobil guidelines for all members of the industry-academic consortium to have standardized fluid properties with other institutions. Also to make useful comparison among cases with each parameter, simulation runs in each study are assigned the same development strategy and will be specified accordingly.

2.2.1.1.1. Diagenetic Scenarios

Multiple sets of porosity and permeability from the static model are the main interest of this study and pose a question: what would be the recovery of those scenarios and how do they compare to one another? To address that question, six cases from Table 2-1 have been examined with flow simulation using identical input and well parameters used in the base case (except for porosity and permeability). These well parameters include the two wells being 200m away from one another with injector rate control at 629bbl/day (100m3/day) and producer BHP control at 2900psi (200bar).

Figure 2-8 presents oil recovery (y axis) versus time (x axis) and the impact of various geologic settings on displacement of oil in the TCC model. Six diagenetic scenarios were examined. The injector injected water at a constant rate of 629 bbl/day (100 m3/day) and producer produced at a constant bottomhole pressure of 2900psi (200bar). The oil recovery at the end of five years water injection varies from 0.32 to 0.42. The rank transformed scenario has the lowest recovery and the behavior is much different from the other settings as it has a much earlier water breakthrough (bend of recovery curve) compared to other scenarios.

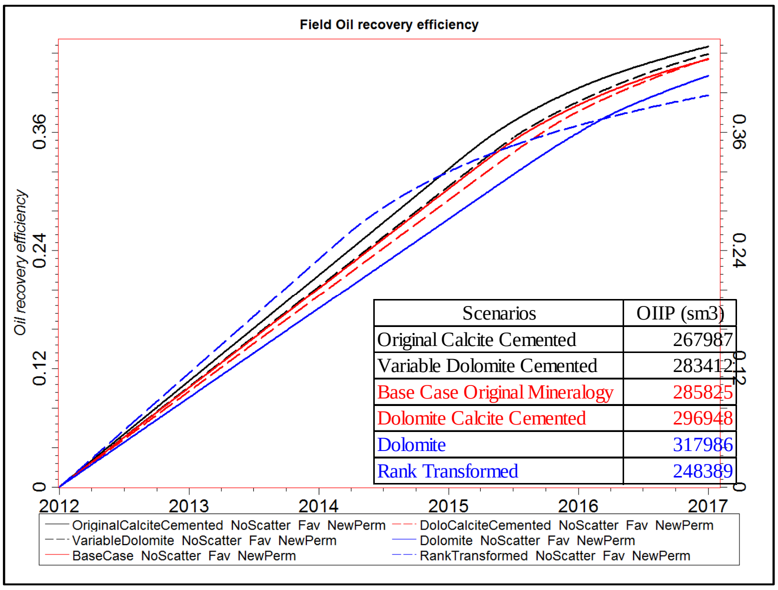


Figure 2-8: Recovery of Six Diagenetic Scenarios

Due to time and scope constraints, simulation runs were focused on scenarios that best represent the outcrop data and assumptions made in line with geology study. Base Case Original Mineralogy is the simplest scenario for the project to begin with. Variable Dolomite Cemented represents a combination of two other scenarios: Original Calcite Cemented and

Dolomite Calcite Cemented. Rank Transformed is made to both preserve diagenetic patterns and take into account core plug porosity-permeability statistics. The following discussions will be focused on these three cases in the flow simulation as they are more representative of the subsurface reservoir.

2.2.1.1.2. No Scatter & Scatter Permeability

Two permeability populated options, No Scatter and Scatter, are implemented in each of the six diagenetic porosity-permeability scenarios. No Scatter, or regular, permeability is derived from Standard Property Calculator which is a proprietary core-plug database from two carbonate fields in the Middle East. While the transform from this database provides the central tendency of porosity-permeability relationships, it fails to acknowledge the noise around porosity-permeability regression. The purpose of Scatter is to have a more realistic permeability variation typically observed in the field. It is not always known what the exact distribution is; however there are usually noise and abnormality that would need to be taken into consideration. In this part the effect of adding Scatter (noise) to regular permeability on recovery is being examined.

Figure 2-9 displays the simulation results of Scatter (solid lines) versus No Scatter (dashed lines) among Base Case, Rank Transformed and Variable Dolomite. Red, blue and black colors in Figure 2-9 represent the three geologic scenarios respectively. Well configurations include the reverse case with producer on the higher ground under BHP control at 2900 psi (200bar) and injection well on the down-dip side pumping 669bbl/day (100m3/day). Scatter means more heterogeneity in the permeability distribution and consequently leads to less recovery as seen in Figure 2-9 due to the reservoir being more complex. However there is not much difference in flow behaviors between Scatter and No Scatter to an extent that necessitates choosing one over another.

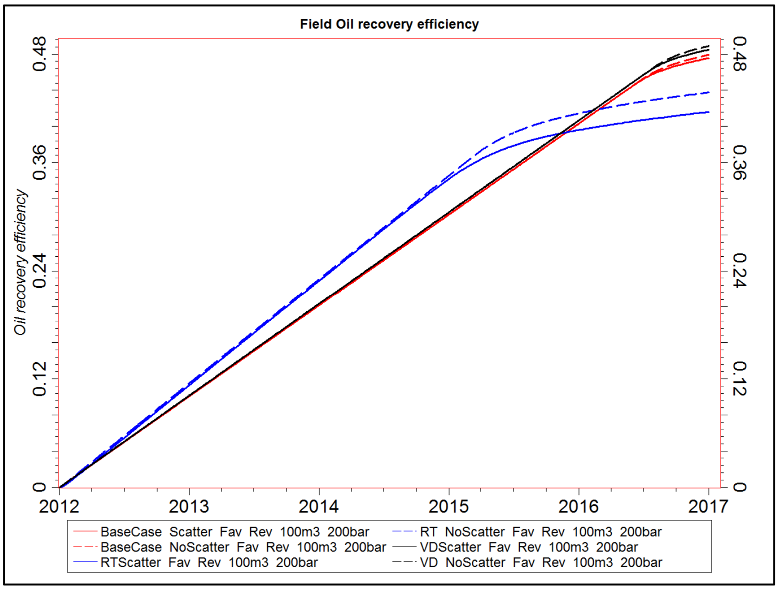


Figure 2-9: Recovery of Two Permeability Options (Scatter versus No Scatter)

2.2.1.1.3. Fluid Mobility Ratios and Crossflow

Two fluid mobility ratios are employed in this project to postulate the favorable and unfavorable relationships between displacing fluid and the fluid being displaced. Details of these two ratios are presented in Table 2-3 and as a result, the mobility ratio between water and oil becomes 0.94 for the favorable ratios and 7.2 for unfavorable fluid mobility ratios (Assuming Krw=0.65 and Kro=1.0).

Figure 2-10 depicts the correlation between recovery and fluid mobility ratios in the case of original porosity and permeability with no scatter. Well settings of this study include a 5-spot pattern with the production well under BHP control at 200bar and four other injectors with injection rate of 629bbl/day (100m3/day) each. There are two groups of favorable (solid line) and unfavorable (dashed line) mobility scenarios. A significant gap between favorable (~40%) and unfavorable (~24%) case recovery factors indicates areal displacement is important during recovery. Mobility ratio therefore is a significant factor. Fluid mobility ratio would have a range of roughly 16% OIIP unrecovered if this reservoir were to be produced with unfavorable displacing fluid ratios. This is due to the fact that unfavorable mobility creates a non-uniform displacement front where fingering is more likely to occur, hence lead to earlier water breakthrough. Once the production well starts producing water, recovery slows down because of oil production rate decline.

In addition, the ratio of vertical to horizontal permeability is also being tested and presented in Figure 2-10. Red color represents the case where vertical permeability equals to permeability in the horizontal direction (Kvh=1), which is chosen to be the standard practice in La Molata project (for simplicity). Black and blue lines mean the ratios are respectively 0.1 and 0.01. Though varying Kvh ratios slightly decreases recovery, the effect is much less pronounced compared to fluid mobility. However since vertical permeability typically is not equal to horizontal permeability in most reservoirs, Kvh as 0.1 or 0.01 would likely represent a more real-life formation.

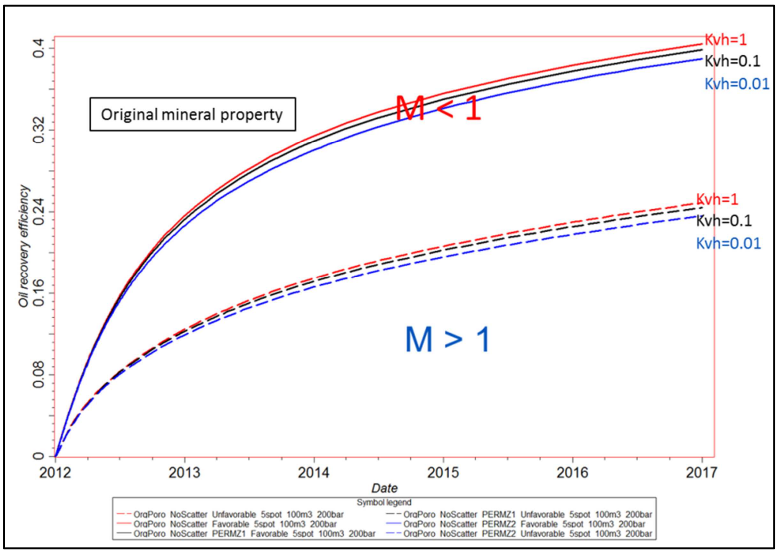


Figure 2-10: Recovery between Mobility Ratios and Kvh

2.2.1.1.4. Relative Permeability and Capillary Pressure

The idea of relative permeability (Kr) and capillary pressure (Pc) was guided to be simple at first and to add complexity as appropriate. To begin with, a single set of drainage (initialization) Kr and Pc curves is applied on the original mineralogy base case. Simulation runs are carried out with only drainage curves. Then imbibition process is set up in addition to drainage: three groups of properties are assigned based on permeability range (Tables 2-4 and 2-5) for flow simulation.

Figure 2-11 presents the recovery of single property curves versus multiple curves based on grouping for the base case. Solid lines represent favorable fluid mobility and dashed lines mean unfavorable mobility. A common theme is observed with both mobility ratios: the recovery of multiple curves is almost identical to high permeability case. This points out the fact that a large portion of original base case permeability is greater than 100mD (Figure 2-11) and therefore is given the corresponding relative permeability. Since Kr assigned to high permeability has lower Swi and Sorw (Table 2-4), it allows more oil to be mobile and be displaced by water resulting in higher recovery for cases with high relative permeability.

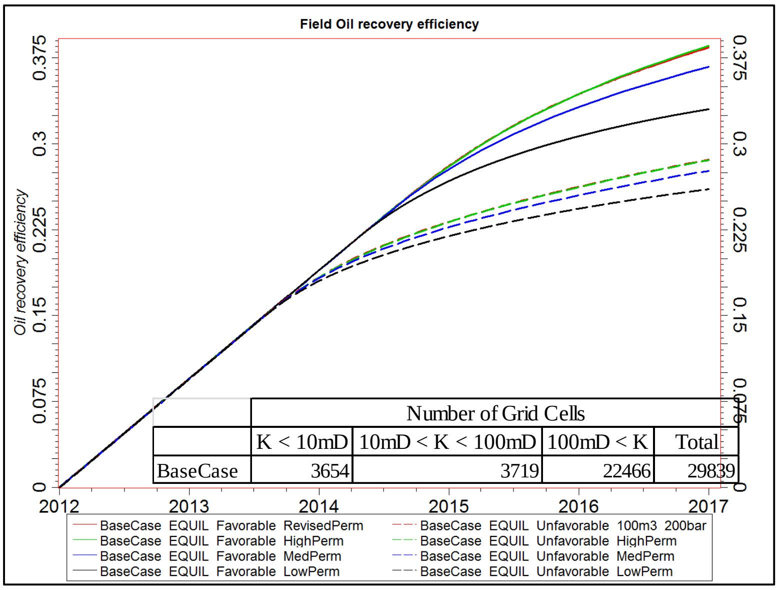


Figure 2-11: Recovery of Multiple Imbibition Curves on Base Case

Figure 2-12 displays the effect of multiple Kr and Pc curves on Rank Transformed and Variable Dolomite, which shows a similar pattern except for Rank Transformed. Solid lines are recovery efficiencies of Variable Dolomite cases with and without imbibition process. The results show that except for when the low-perm curves are used for imbibition, other cases have almost identical recovery. This implies medium and high Kr curves do not have much impact on the recovery of Variable Dolomite compared to multiple curves for imbibition process. Similarly, the effect of Kr and Pc curves is insignificant for Rank Transformed (about 2% difference).

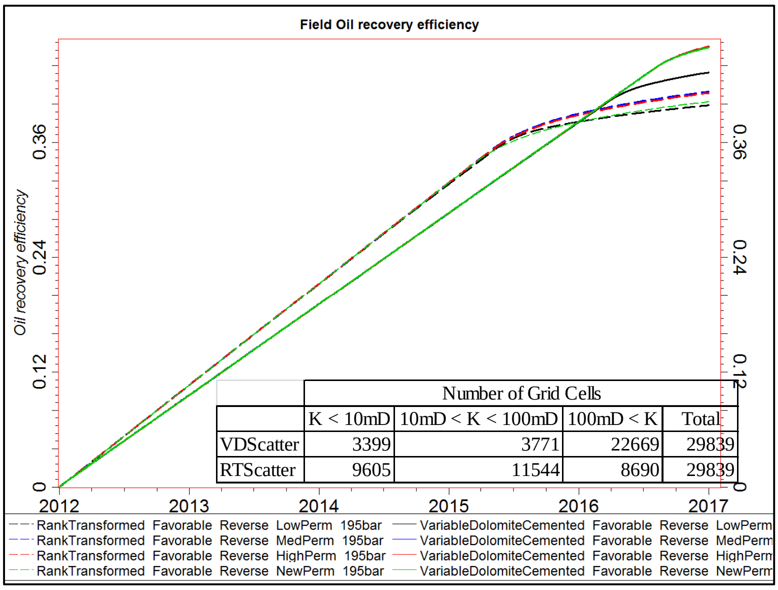


Figure 2-12: Recovery of Multiple Imbibition Curves on

Rank Transformed and Variable Dolomite

2.2.1.2. Development Strategy

Apart from simulation input, development strategy is the process of identifying well completions, locations and patterns for waterflood study. Each parameter is being examined to test and correlate the effect of various carbonate systems on recovery processes and find out the answer to the questions asked by geologists as they constructed the static model.

2.2.1.2.1. Producer Locations

One of the important questions is where to produce oil from in the model. Two producer locations have been selected to address this question: one being on the lower end, or down-dip, and the other on the higher ground, or up-dip, of TCC unit (Figure 2-13).

Figure 2-13 illustrates water saturation after 2 years and a half of injection into the reservoir. Gravity will pull water down in an inclined displacing front and the oil on the upper portion remains trapped. Meanwhile when water is injected from down-dip, gravity (with cross flow) forms a more stabilized front in which water displaces oil more uniformly towards the producer. Once water breakthrough occurs, production rate dramatically plummets due to water production.

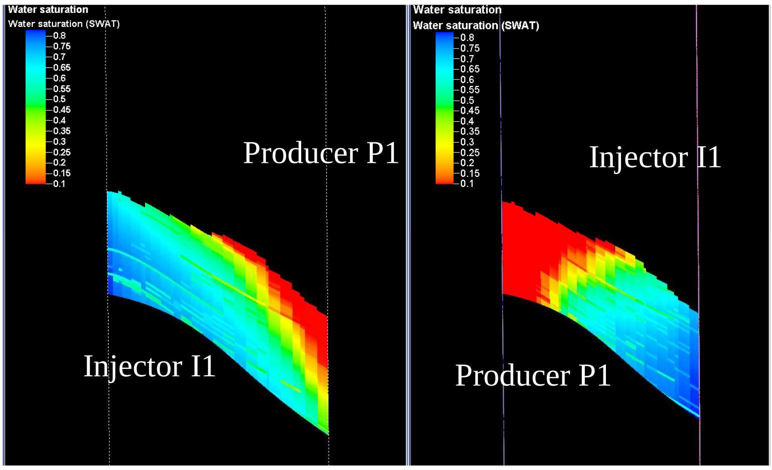


Figure 2-13: Water Saturation at 2.5 Years for Two Well Locations

Figure 2-14 shows that producer on the higher ground would recover more oil with water injection from lower ground. It points out there is roughly 16% OIIP unrecovered when mobility control is favorable between two locations (solid lines) and 12% when mobility is unfavorable (dashed lines). The effect of sequence boundaries as barriers during recovery process is discussed later in the conclusion.

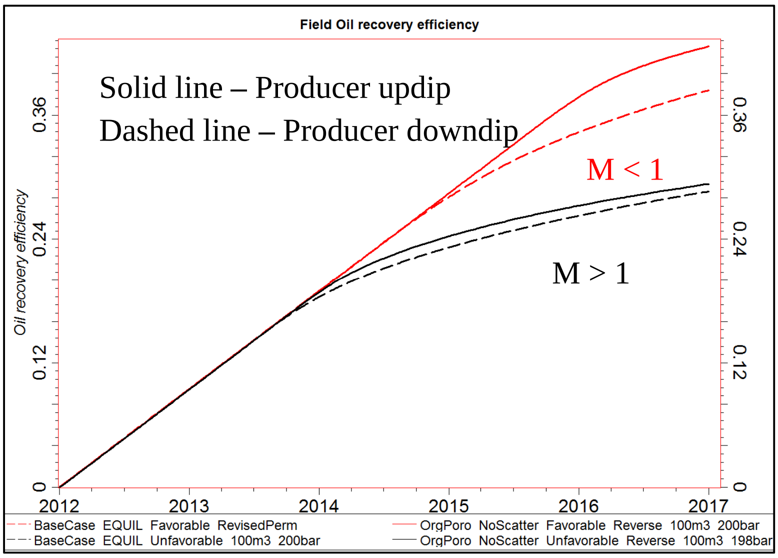


Figure 2-14: Recovery of Two Producer Locations

2.2.1.2.2. Well Completions

Thus far only full-interval completion is considered for waterflood which covers a thickness of 30m. In practice most wells are completed to produce from certain pay zones. As this is a reservoir-analog study, the purpose is to replicate that design and explore various completion scenarios to see what works best. This study features the producer on the up-dip side and injector on the lower end of TCC unit.

Figure 2-15 demonstrates the effect of several completion intervals on recovery efficiency with Kvh being 0.1. The blue lines (solid and dashed) present the cases when the injector is completed at the bottom and the producer at both top and bottom. Meanwhile, the black lines (solid and dashed) are when the injector is completed at the top. The only solid red line in Figure 2-15 is recovery from the base case where both wells have full completion. The part being shown in Figure 2-15 is a very small time period within the last 6 months of simulation (the earlier part is almost identical among cases). Variation in recovery of different completions therefore is only about 2% additional recovery from the case with producer completed on top and injector on the bottom compared to full completion. This suggests that full range completion is not required to displace oil and completion intervals do not play a significant role in the recovery process in this case.

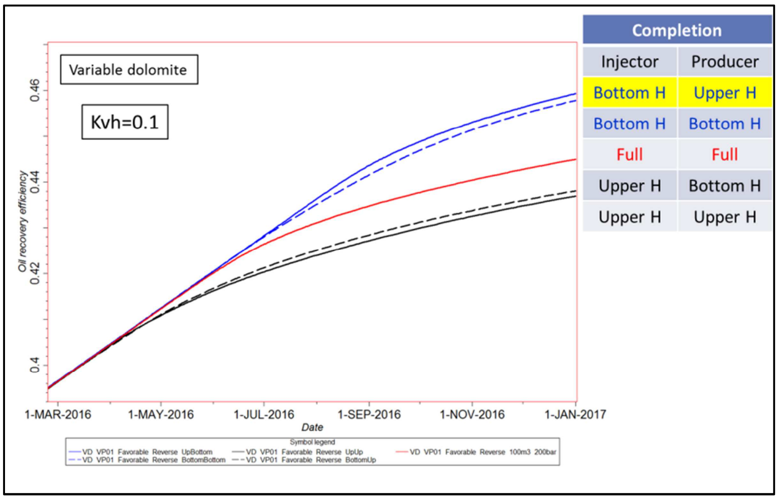


Figure 2-15: Recovery of Various Completion Intervals

2.2.1.2.3. Well Patterns

This section discusses the use of common practice well patterns instead of a single injector and producer system. To assess economic viability, one needs to also consider recovery in terms of PV injected among these scenarios and seek the most optimized setup for their waterflood. There are 4 well patterns being examined including regular 5-spot, 9-spot, and inverted 5-spot, 9-spot. Figure 2-16 displays the recovery of two injection patterns (regular 5-spot and 9-spot) in two fluid mobility ratios with respect to PV injected. Red lines are recovery factors of 5-spot while black lines are those of 9-spot pattern. The solid lines represent favorable fluid mobility ratios and dashed lines display unfavorable mobility ratios. As shown in the figure, though 5-spot and 9-spot appear to recover about the same amount of oil in the end of simulation, water injection for each case is remarkably different. It is learned from Figure 2-16 that at 2.5 PV injected, 5-spot has already recovered more than 30%, an amount that takes 9-spot more than 5 PV injected to produce.

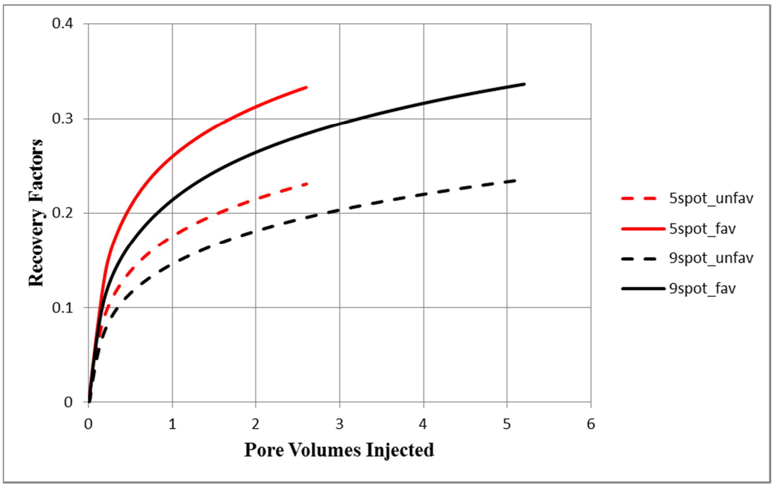


Figure 2-16: Recovery of 5-spot and 9-spot versus Pore Volume

Based on Figure 2-17, the highest recovery is 5-spot inverted (25%) with favorable fluid mobility ratios while the lowest is 9-spot injection (15%) with unfavorable mobility ratios. Figure 2-17 also indicates with the same amount of PV injected more production is gained with inverted 5-spot compared to inverted 9-spot pattern. Since TCC is a small unit, the benefit of increasing number of wells and volume of water is not obvious. Therefore it makes more economic sense to invest in inverted 5-spot design in terms of cost-effectiveness.

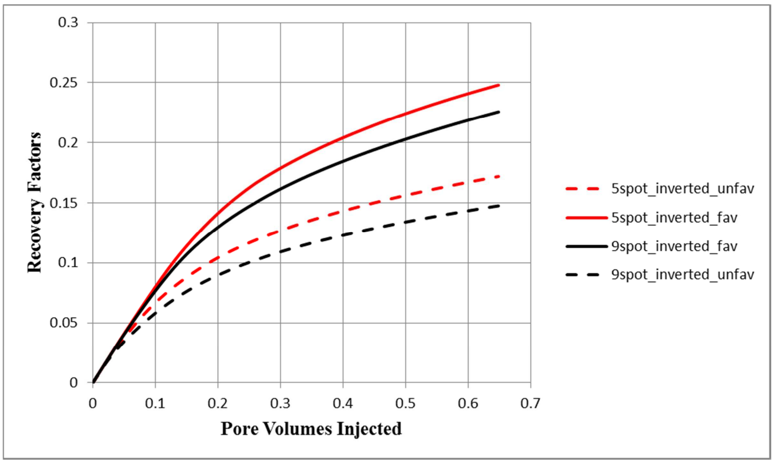


Figure 2-17: Recovery of Inverted 5-spot and 9-spot versus PV

2.2.1.2.4. Streamline Simulation

TCC unit is experimented with streamline simulation to reduce computation time and/or help guide the upscaling process. This is a preparation step for streamline study in DS3 which will take place later in the project. Streamline simulation is compared with black oil simulation for verification purposes. In this study the producer is on the up-dip under BHP control at 2828psi (195bar) and the injection well on the lower ground injecting 629bbl/day (100m3/d).

Figure 2-18 displays the comparison between black oil with drainage relative permeability curves and streamline simulation (imbibition relative permeability curve input not available). Simulation results show almost identical recovery with favorable mobility ratio, though their breakthrough timing is slightly different. Unfavorable mobility ratio displays slight difference in recovery factors (about 4%) between the two simulators. This suggests that streamline can be used to save simulation time with larger models which will be discussed later in DS3 study.

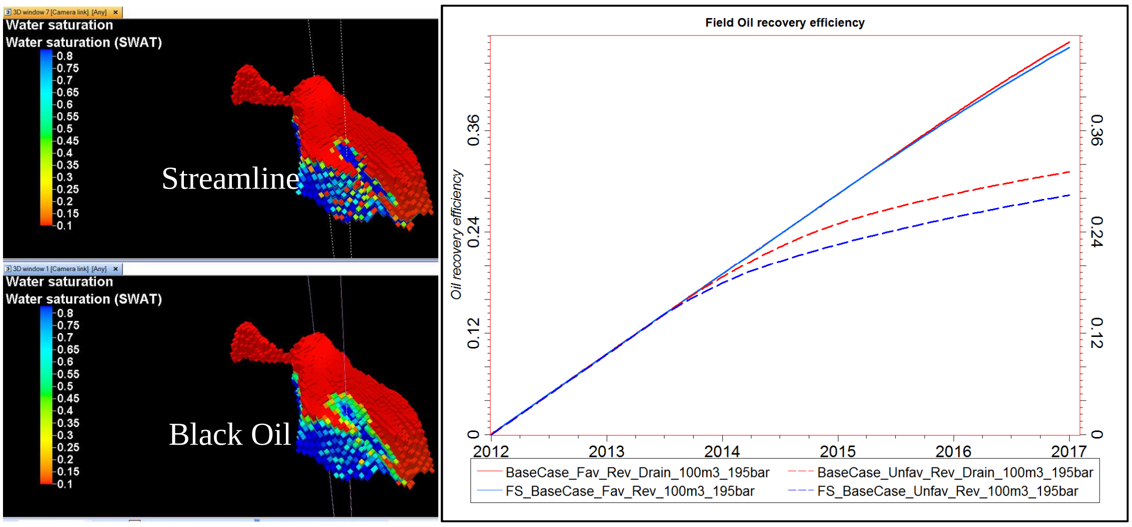


Figure 2-18: Streamline Simulation versus Black Oil Simulation

2.2.2. Simulation Gridding

TCC unit has a 10x10(m) lateral grid resolution and cell thickness of 0.5m. It is roughly 300m in width and 600m in length with 29831 active cells in the model. The simulation gridding process, or coarsening, seeks to reduce computational time while maintaining reservoir heterogeneity and consists of two separate steps: 'Scale up structure' and 'Scale up properties'.

Figure 2-19 describes the two steps of 'Scale up structure' including lateral and vertical coarsening. Lateral coarsening defines new grid resolution in the X and Y directions. In this figure the initial resolution is 10x10(m) and has been scaled up to 20x20(m). This alone would increase the cell volume by a factor of 4. After that, vertical resolution needs to be taken care of by relayering the zone in between a top and bottom horizon. TCC layers are created with a uniform thickness of 0.5(m) starting from base and will be coarsened up by increasing the thickness to multiple levels and compare performance with initial cases.

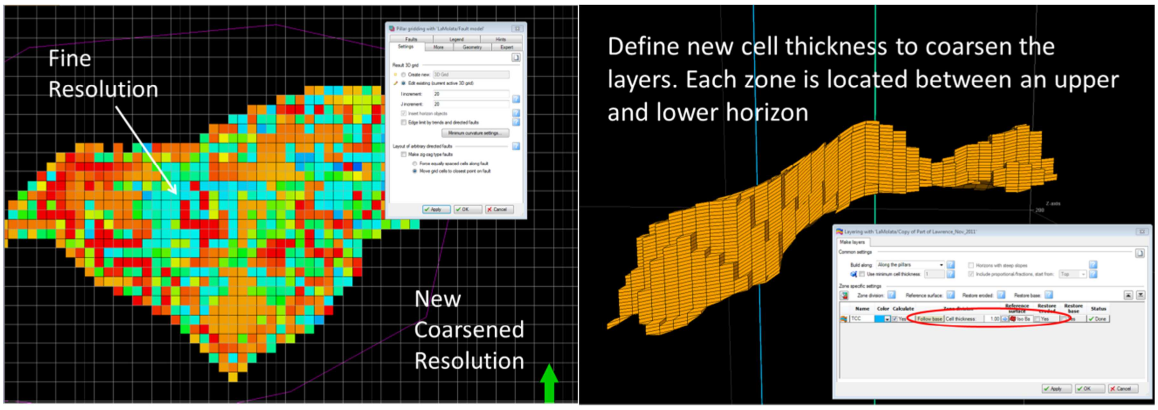


Figure 2-19: ‘Scale up structure’ includes lateral and vertical upcaling

A significantly important step after structure being coarsened, ‘Scale up properties’ (property sampling methods) will determine if the new cases are able to represent original fine grid performance. Figure 2-20 describes available sampling methods for continuous properties and what they are about during the process. Most commonly arithmetic averaging will be used for porosity sampling and harmonic averaging for permeability upscaling. However in this study, more attention is given to the Power method which generalizes other methods by taking in an exponential parameter. For instance, when that parameter goes to negative infinity the method tends toward minimum, -1 is equivalent to harmonic, 1 is equivalent to arithmetic, 2 is equivalent to Root Mean Square (RMS) and infinity would tend to maximum. Power averaging allows flexibility to work around preset methods offered in the software package and fine tune properties when they need to be matched with the original case.

Arithmetic	$P = \frac{\sum_i w_i p_i}{\sum_i w_i}$	Typically used for additive properties such as porosity, saturation and net-to-gross. Volume weighting will produce a more appropriate arithmetic mean when input values have variable presence within the resulting cell. A property such as oil saturation, for which the value is only meaningful in relation other properties, should be weighted by the properties it depends on, i.e. porosity and net-to-gross. This will ensure that the hydrocarbon pore volume remains constant when upscaling.
Harmonic	$P = \frac{\sum_i w_i}{\sum_i \frac{w_i}{p_i}}$	Gives the exact effective permeability vertically if the reservoir is layered with constant permeability in each layer. The harmonic mean works well with log normal distributions. It is used for permeability because it is sensitive to lower values. The method is not defined for negative values.
Geometric	$P = \exp\left(\frac{\sum_i w_i \log(p_i)}{\sum_i w_i}\right)$	Normally a good estimate for permeability if it has no spatial correlation and is log normally distributed. The geometric mean is sensitive to lower values, which will have a greater influence of results. The method is not defined for negative values.
Root mean squared	$P = \sqrt{\frac{\sum_i w_i p_i^2}{\sum_i w_i}}$	Will set a bias towards higher values.
Minimum		Selects the lowest value from all the original cells that contribute to an upscaled cell.
Maximum		Selects the highest value from the original cells that contribute to an upscaled cell.
Power	$P = \sqrt[x]{\frac{\sum_i w_i p_i^x}{\sum_i w_i}}$	This method generalizes several of the above methods by accepting an exponent parameter; a value of 1 is equivalent to arithmetic averaging, a value of 2 is equivalent to RMS, and a value of -1 is equivalent to harmonic. The exponent can be negative and/or fractional, but not zero. In theory, as the exponent tends to 0, the power average tends to the geometric average. Similarly, as the exponent tends to infinity, the power average tends to the maximum, and to minus infinity to the minimum. In this sense, each of the above methods have an "equivalent exponent" which indicates the methods' relative biases toward higher or lower values, i.e. generally, minimum < harmonic < geometric < arithmetic < RMS < maximum.

Figure 2-20: Available Sampling Methods in Petrel

2.2.2.1. Lateral Coarsening

Figure 2-21 displays the calculated pore volumes with multiple porosity sampling methods (permeability sampling method is fixed with Power 3 in this case) and their recovery factors versus the base case (red line). Since porosity has a direct impact on pore volume, varying it will help match the recovery before breakthrough occurs. The blue dashed line represents the matching case with porosity sampled using Power 3 method (0.6% PV error) which gives a stronger preference towards higher values. Most other methods result in higher recovery because of lower pore volume from sampling as presented in the table of Figure 2-21. Multiple attempts have been made to figure out the best case that resembles original base case the most and it turns out, in contrast of common practice, arithmetic averaging is not what should be applied on porosity. In the end, Power 3 averaging is used for porosity and harmonic averaging for permeability since they match initial model performance.

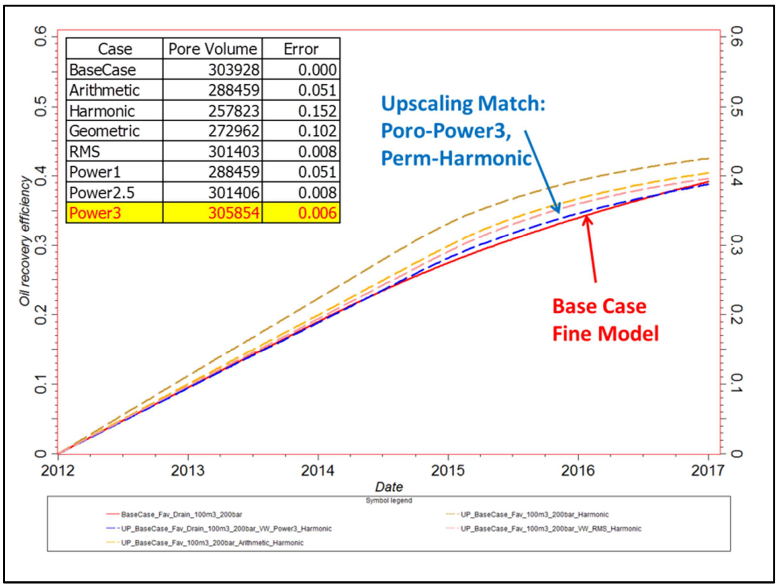


Figure 2-21: Matching Porosity with Power 3 Sampling Method

Figure 2-22, on the other hand, describes the matching process of permeability after breakthrough. Different permeability sampling methods are attempted and porosity sampling remains to be Power 3 as discussed earlier. Varying permeability sampling mainly has an impact on recovery after breakthrough. The harmonic method gives a good match (1% recovery error) because it gives more preference toward lower permeability values and therefore better retains these values to account for permeability variation. Power method with -2 or -3 as exponential parameter is not a good choice since it is in too much favor of lower values and therefore does not provide an inadequate fit.

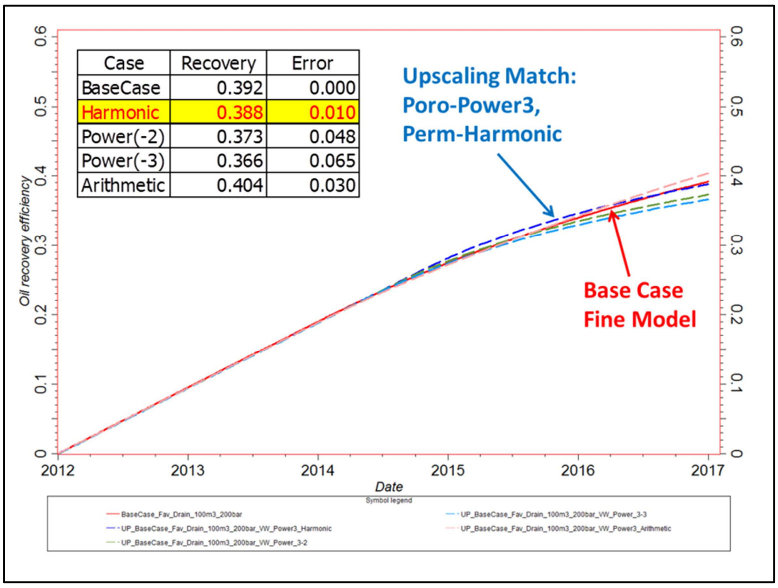


Figure 2-22: Matching Permeability with Harmonic Sampling Method

2.2.2.2. Vertical Coarsening

Thus far mainly coarsening up in the lateral direction has been done on TCC model and there is a need to explore and generate a workflow through which engineers can take advantage in their effort to build simulation grid cells. This study aims to find out how much reservoir complexity can be lost and to what extent geomodel cells can be scaled up so that they both represent rock properties and reduce computation time. The initial model layer thickness is 0.5(m) proportionally in one zone. It will be coarsened to 1, 2 and 4(m) as Figure 2-23 shows a cross section of their permeability variation in different resolutions. Note that the property is sampled from 5x5(m) grid using Volume Weighted algorithm and Power 3 sampling method from previous cases of lateral coarsening. From Figure 2-23, it is learned that very thin barriers from the initial grid gradually merge into larger grids and increase permeability in the affected area. This will have an impact on the waterflood recovery processes later on when the scaled up grids are simulated for validation.

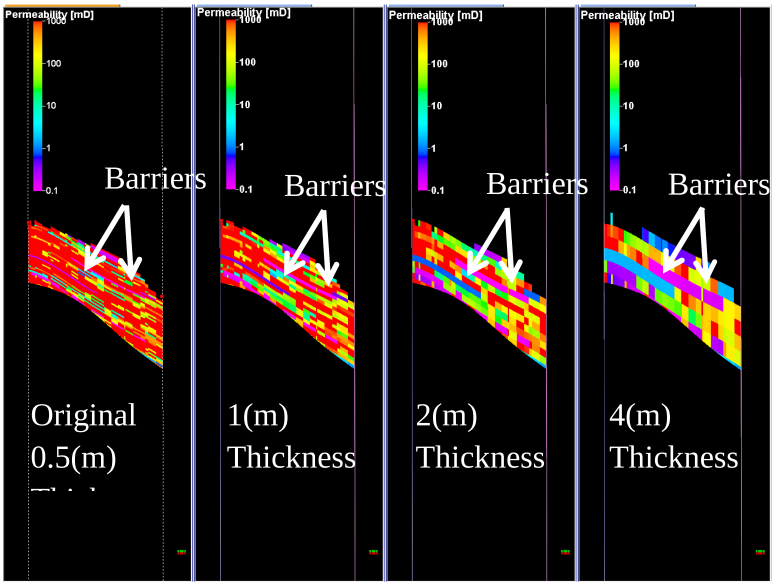


Figure 2-23: Change of Permeability Variation using Power 3 Sampling Method

Flow simulation for each case then follows to observe behaviors in each resolution. Early breakthrough occurs with scaled up models in Figure 2-24 because there was a lower permeability area consisting of thin barriers in between the two injection and production wells. After layer thickness is increased these barriers have been averaged with higher permeability cells from above and beneath (Figure 2-23), therefore resulting in them to become much less effective which is not true in reality. Water front observation shows that there is minimal movement in the barrier layers of the initial model whilst water approaches the production well relatively quickly in scaled up models, specifically in areas where there were low-permeability layers (Figure 2-24).

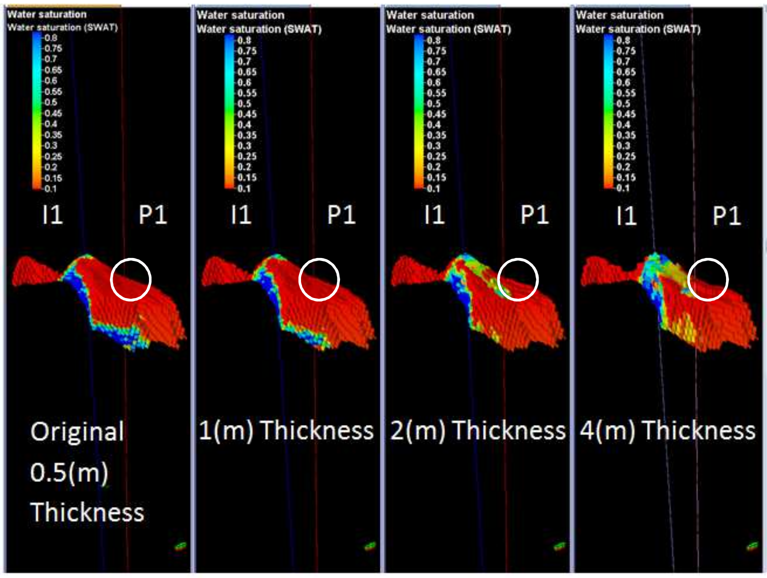


Figure 2-24: Water Saturation of Scaled Up Models after 5 years

As simulation results indicate water breakthrough take place earlier in the scaled up models, it is important to find a better way to sample permeability into the new grids to match initial flow behaviors. By attempting various methods of sampling properties, the recovery and watercut of scaled up grids have been matched with that of the initial model in Figure 2-25. For all three thickness cases, matching porosity method is arithmetic averaging while permeability sampling methods vary. Cases with 1 and 2(m) thickness are matched by harmonic averaging (Power with -1) and the case with 4(m) thickness is matched by Power 3 averaging. The best match with original model (red lines) is 2(m) thickness (black lines) and the recovery factors of the two cases are almost identical. There is a slight difference between 0.5(m) thickness and 4(m) thickness which is understandable since the cells have increased significantly in size. The time of water breakthrough is similar among 4 cases and the movement path is displayed in Figure 2-20. An apparent improvement is observed in Figure 2-26 compared to Figure 2-24 after porosity and permeability are sampled using better methods.

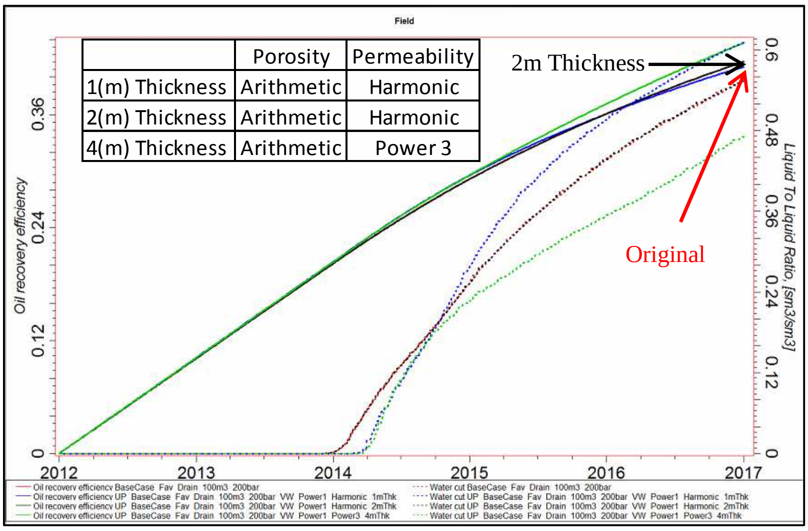


Figure 2-25: Sampling Methods for Porosity and Permeability to match Recovery and Watercut

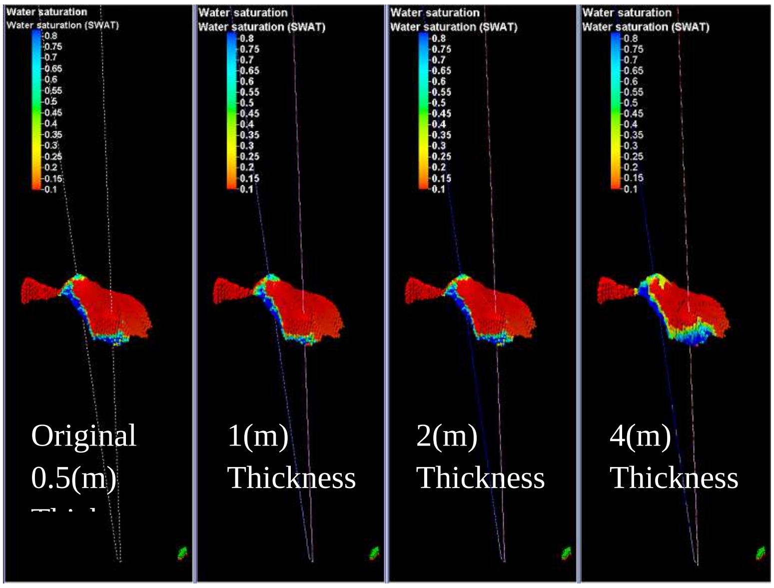


Figure 2-26: Water Saturation after Porosity and Permeability are matched

2.3. Reefal Platform System (DS3)

While TCC is the uppermost, smallest and least complex unit of La Molata, lying right underneath it is the largest and most heterogeneous unit DS3 which covers an area of roughly 2.5 km^2. Therefore TCC study has laid out the stepping stone to further examine DS3 with greater complexity. Not only being larger in size, DS3 is an interesting unit because it is made up of zones that allow no flow communication between them. This poses a challenge and plays an extremely important role in the displacement process. More 'tailored to the zones' well design is required to tap into each connected volume separated by erosion surfaces. Streamline simulation takes place in a large portion of DS3 work. Again the first step is to experiment with engineering designs and rock & fluid properties to respond to these sample questions:

- For the reefal platform system, how efficient would a vertical well drilled up-dip be able to drain the reservoir?
- How much oil would be left behind because of progradation and lateral pinchouts of reefs?
- Would a horizontal well be required and should it be along strike (to intersect the along strike discontinuity of reef wedges) or down-dip to intersect the maximum number of progrades?

Secondly, upscaling is done on the model to find out how to best enlarge fine grid cells without losing too much of heterogeneity. The new grids are then validated with simulation results from the initial model. Simulation gridding includes lateral and vertical coarsening as well as matching the sampled porosity and permeability to match initial model performance.

2.3.1. Engineering Design

In order to address the questions given to DS3, it is important to identify where the facies associated with high permeability are in DS3 and conduct a preliminary study. Figure

2-27 displays the entire DS3 model with the West portion highlighted showing light green Coral Boundstone concentrations. Coral Boundstone forms the progradation and lateral pinchouts of reefs on the updip side of DS3. The area around these reefs is the main focus of study is of reservoir quality.

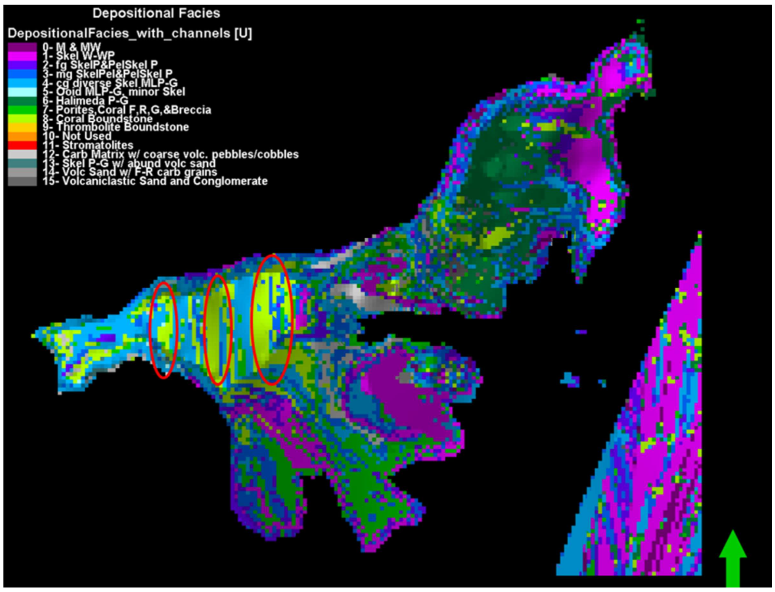


Figure 2-27: Facies Distribution of DS3

Then a simulation case is setup with three pairs of injector and producer along the strikes as shown in Figure 2-28. Each injector is approximately 100m away from its producer and a pressure gradient of 0.12bar/m is specified in between the two wells for development strategy. Variable Dolomite (Scatter) with favorable mobility ratios is implemented in this scenario. The purpose is to perform a waterflood study and understand where and how much oil would be trapped and if there is discontinuity within the reefs.

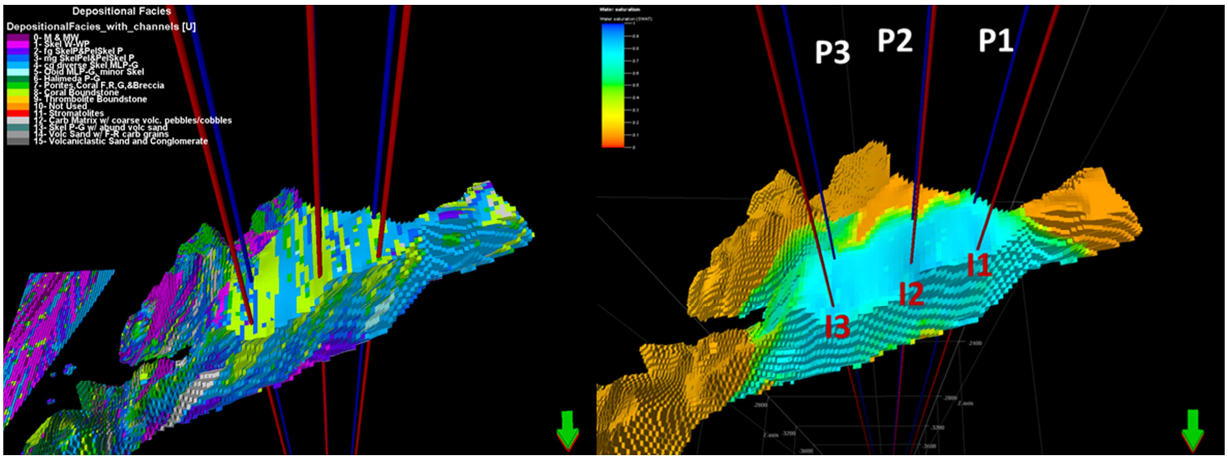


Figure 2-28: Three Injector & Producer Pairs along Strikes

Figure 2-29: Oil saturation after 5 years of injection shows that the majority of oil left behind is trapped in those facies with lower permeability including Mudstone and muddy wackestone, Skeletal wackestone and packstone, Fine-grained skeletal packstone and Medium-grained skeletal/peloidal packstone and peloidal/skeletal packstone (Benson et al, 2014). Beside residual oil saturation, complex reservoir heterogeneity is also a substantial factor in keeping waterflood from recovering the entire oil volume in place.

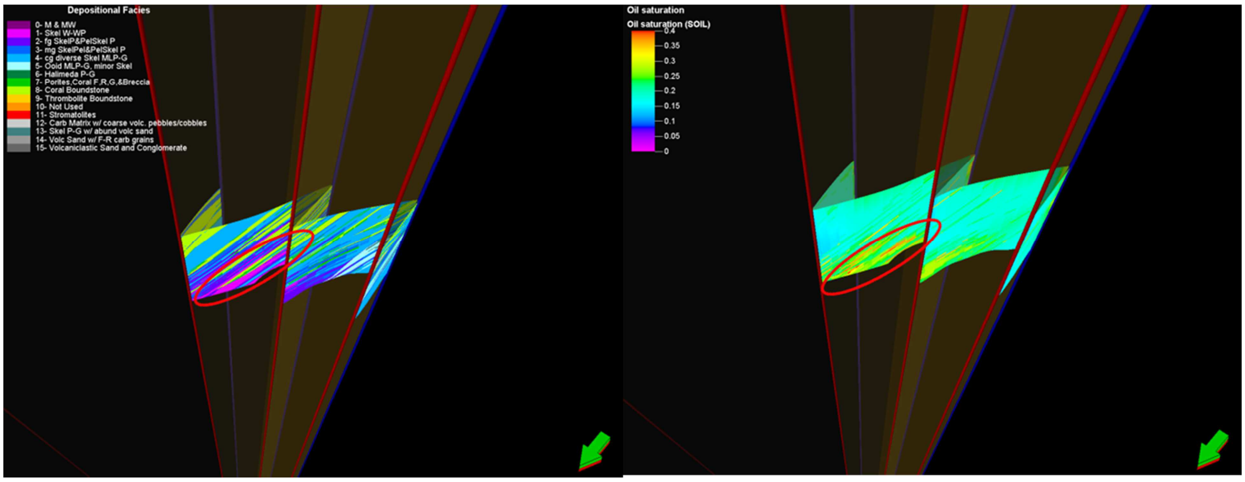


Figure 2-29: Oil left behind after 5 years of simulation (Facies and Oil Saturation)

Another development scenario is with three vertical wells on the updip having extended laterals going downdip to intersect all the inclined progrades. Each vertical well has two laterals and the production well is in the middle of the other two. Production well is under BHP control of 190bar while injection wells are under BHP control of 197 bar. Multiple imbibition curves and favorable mobility ratios are implemented for Variable Dolomite (Scatter).

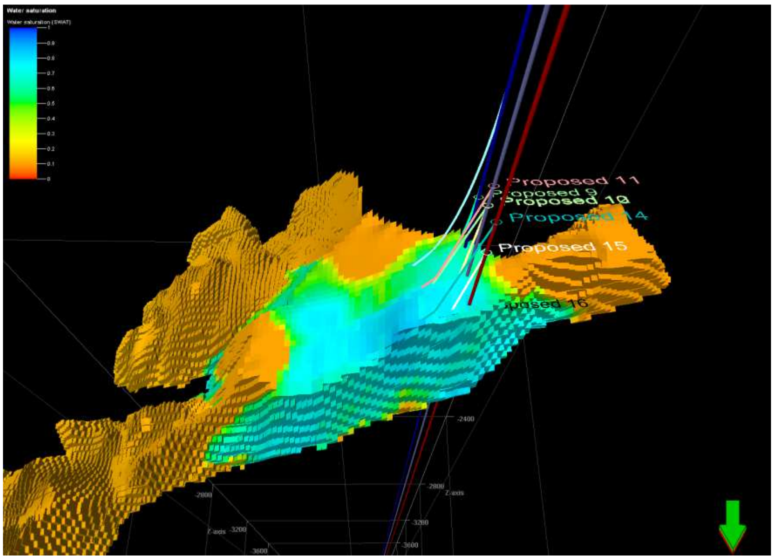


Figure 2-30: Fish bone lateral design for oil displacement

Figure 2-31: Simulation results show that low permeability strongly correlates to the oil trapped in reservoir rocks. Most of the unproduced oil lies at the bottom where there are less flow conductive facies with water tends to go through higher permeability channels and leaves out oil in lower permeability areas. This could be improved by increasing the displacing fluid viscosity and stabilizing displacement front using polymer. Another possibility is to flood into the low permeability areas first while plugging other high permeability ones allowing oil to be recovered from low permeability areas.

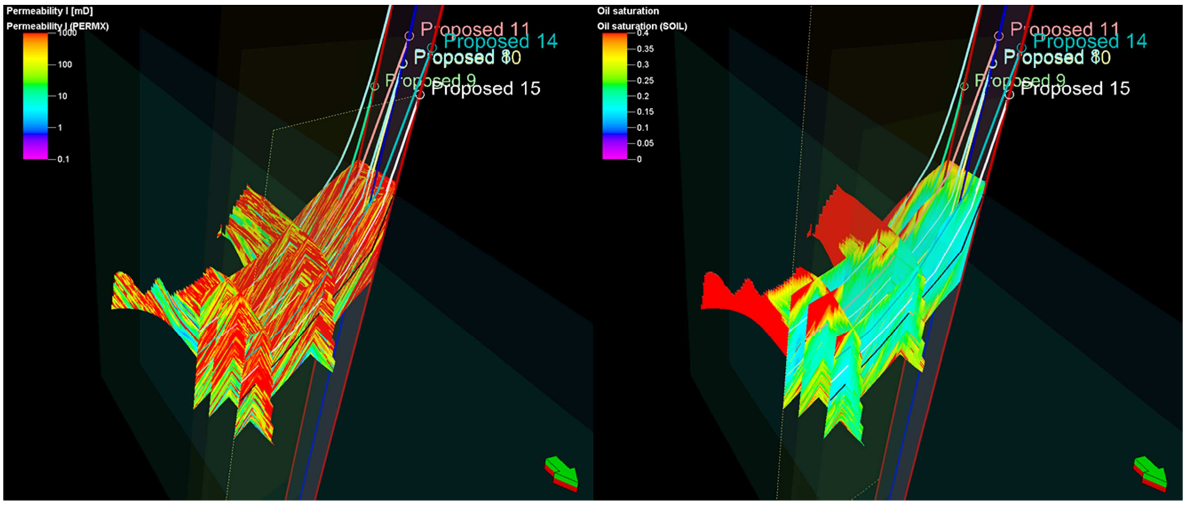


Figure 2-31: Permeability and Oil Saturation after 5 years of simulation

It is obvious that DS3 is a large-scale model and there is a need to narrow down the study area. Instead of looking at one large model, simulation will focus on the updip part where permeability is most likely favorable for fluid flow. Therefore a smaller version of DS3 has been extracted as shown in Figure 2-32.

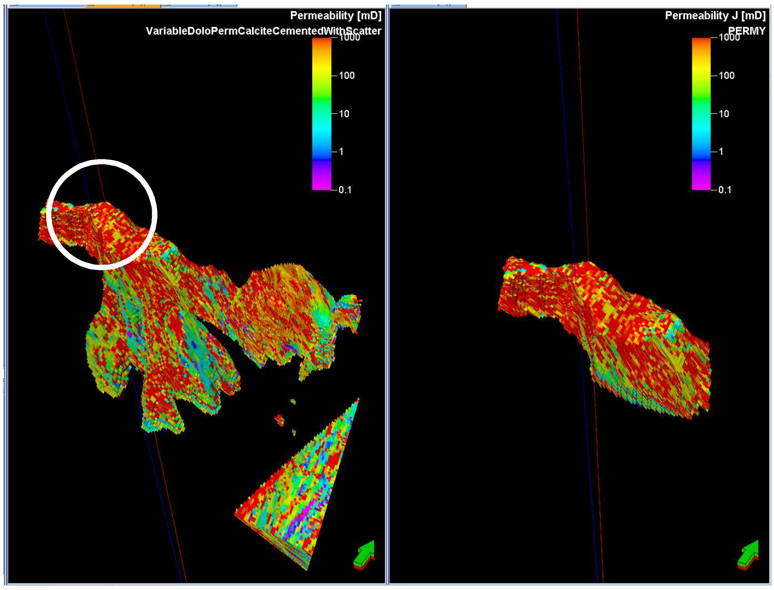


Figure 2-32: Permeability of DS3 and the Study Area

2.3.1.1. Simulation Input

Following the study of TCC unit, DS3 is mainly examined through the three diagenetic scenarios: Base Case Original Mineralogy, Rank Transformed and Variable Dolomite for comparison. Permeability populated options are incorporated into the model for their effect on recovery. After that, fluid mobility ratios are studied for flow simulation with this carbonate reefal system.

2.3.1.1.1. Diagenetic Scenarios

In this study, simulations are performed to examine the effect of various diagenetic models on recovery of DS3 reefal platform system including Base Case (blue), Rank Transformed (black), and Variable Dolomite (red). There are I1 (injector) and P1 (producer) shown in Figure 2-32 for the injection scheme. Injection rate is at 62900bbl/day (10,000m3/d) and production well BHP control is 190bar. Favorable mobility ratios are implemented for all three cases for comparison purposes. This well setting is to address the question how efficient would a well drilled updip be in draining the reservoir. Figure 2-33 shows the most difference is between Variable Dolomite and Rank Transformed (~10%). This is explained by the majority (77%) of Variable Dolomite grid cells having permeability higher than 100mD. Meanwhile Rank Transformed has roughly 40% of its cells in the range from 100mD and above. Base Case has 61% of the cells with permeability higher than 100mD. Given that the three cases have approximately the same amount of grid blocks, Variable Dolomite therefore has the highest permeability, resulting in the most recovery. Assuming favorable mobility ratios and pressure support, up to 65% recovery can be achieved with one production well and one injection well drilled along strike on the updip of DS3. Permeability with Scatter (dashed lines) has also been experimented and shows insignificant difference from non-Scatter cases.

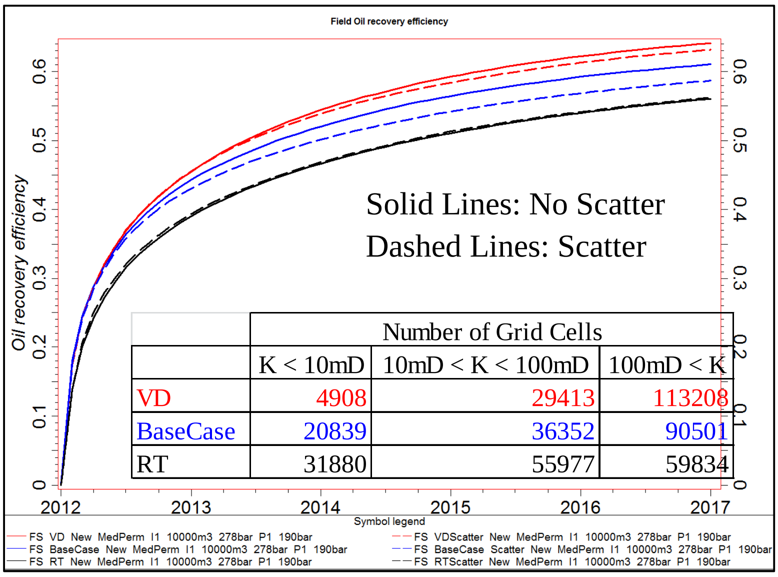


Figure 2-33: Recovery of Three Main Diagenetic Scenarios

2.3.1.1.3. Fluid Mobility Ratios

Favorable and unfavorable mobility ratios have been proven to play a significant role in the hydrocarbon recovery of TCC unit. The study of DS3 also shows that areal displacement is the key to more oil recovery out of the rocks in the area around I1 and P1. Figure 2-34 reveals that if mobility ratios were not favorable, an amount of roughly 17% recovery would be left behind. Variable Dolomite unfavorable (red dashed lines) yields 48% as compared to 65% of favorable mobility ratios. Similarly unfavorable Base Case recovers 46% as to 61% of favorable mobility ratios. Lastly, Rank Transformed case has roughly 19% oil left behind if mobility ratios were unfavorable.

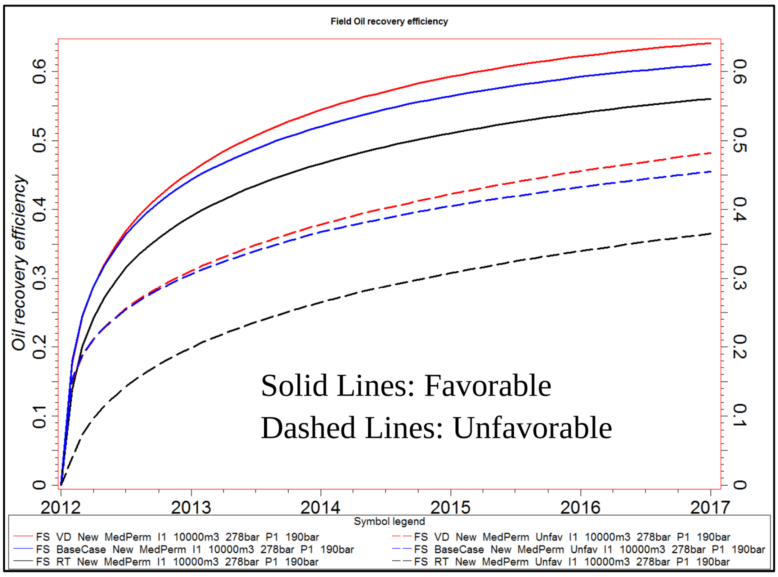


Figure 2-34: Recovery between Mobility Ratios

2.3.1.2. Erosion Surfaces

In order to well represent the geometry of layers in the model, DS3 was constructed using different coordinate systems to resemble the layer orientation observed in the field (Benson *et al.* 2014). This method of having separate coordinate systems creates a problem with the streamline simulator: it does not automatically recognize non-neighbor connections and then assumes there are surfaces through which there is no flow communication as shown in Figure 2-35. The following simulations are done under this assumption: what if there were erosion surfaces in this reservoir-analog formation? What could be learned from that? This part of study examines the scenario where flow is allowed within each zone but not in between and the optimal approach to produce from such a reservoir.

The DS3 updip area is divided into smaller zones (Figure 2-35) by horizons or unconformities across the sector and since these zones are non-communicating with one another, a vertical well will most likely fail to recover the whole sector. The sector somewhat is similar to TCC on a larger and more complicated scale. Two porosity-permeability scenarios generated from the facies model will be employed for flow simulation: Variable Dolomite and Rank Transformed. The former is characterized as being highly permeable and relatively less complex whereas the latter has lower permeability and more heterogeneity. Their Dystra-Parsons coefficients are low compared to most real reservoirs which fall into the range from 0.7 to 0.9. This could be explained that much more detailed information is available for an outcrop analog model, zone permeability and thickness have been averaged out during calculation. Variable Dolomite models also have smaller pore volume (1.43x10^6 m3) than those with Rank Transformed properties (1.74x10^6 m3).

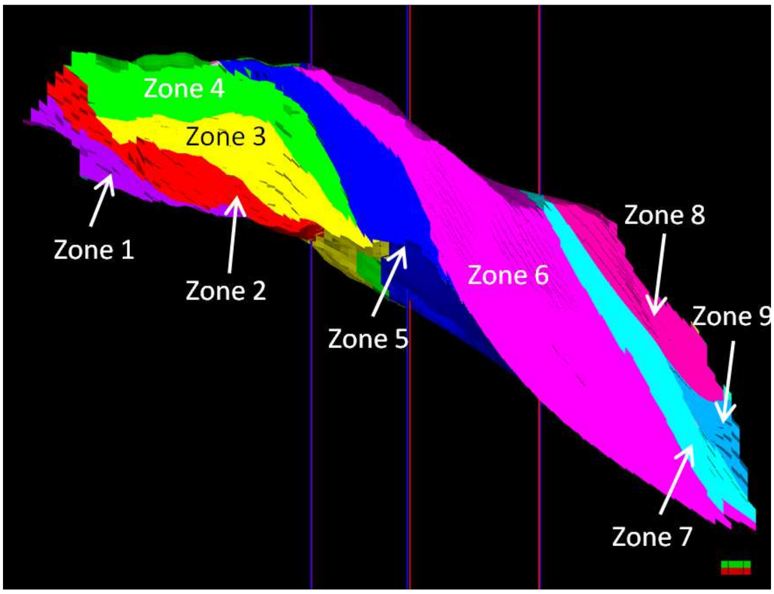


Figure 2-35: Connected volumes showing zones which are non-communicating (South view)

A well design study was carried out to determine optimal locations and completion intervals to achieve the best recovery possible. Previous simulation cases considered wells completed for the whole reservoir thickness which is approximately 40m. Alternative completion schemes were also examined using one pair of vertical injector and producer to examine an area of interest based on facies distribution. These areas are along strikes which are believed to be more permeable for fluid flow. Figure 2-37 presents a top view of the well locations for 3 pairs and where they intersect the more permeable facies, particularly (6) Halimeda P-G, (7) Porites Coral & Breccia and (8) Coral Boundstone. These facies and their distribution are one of the most important factors in determining well locations.

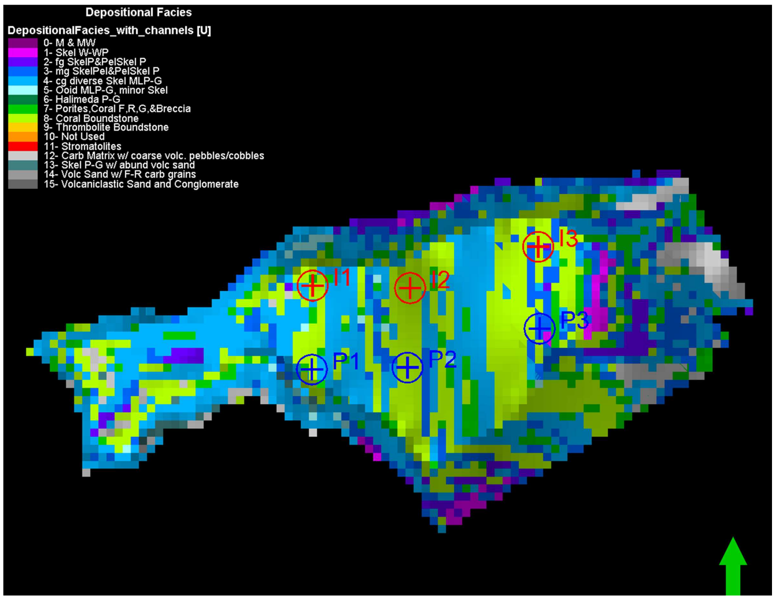


Figure 2-36: Well Locations in DS3 (Top view)

Well design:

Half completion intervals: each of these pairs includes four cases with varying top and bottom perforation intervals to see the effects different completion scenarios have on the recovery efficiency given geology features of the sector model.

Pair1 (I1 vs P1)

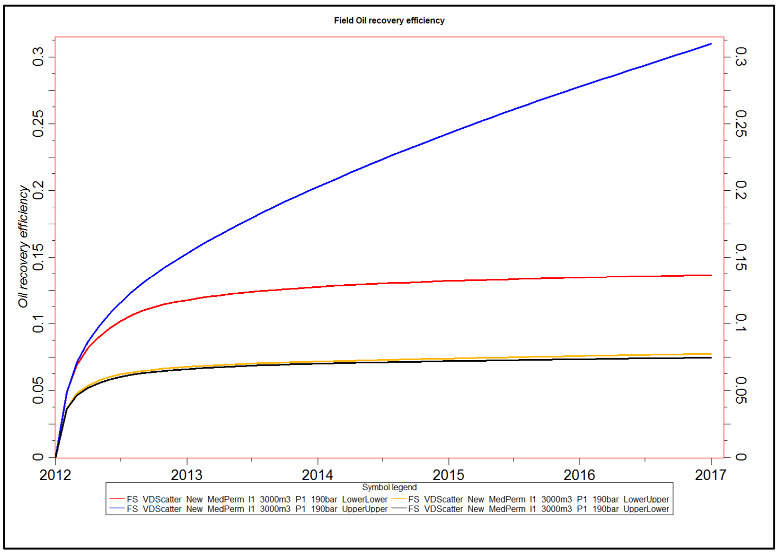


Figure 2-37: Recovery Efficiency of Pair1 Half Completion Intervals

Figure 2-37 shows the case with upper-completed injector and upper-completed producer recovers the most oil (30%), twice as much as the second best recovery (15%) with lower-completed wells. From Figure 2-38 showing the best recovery case after 5 years it is learned that I1 upper completion encompasses a combination of zones 4, 5, 6 and water injection helps sweep more oil to P1 upper completion. What about lower production intervals? From Figure 2-38 it can also be observed that no production from Zones 5 or 6 would be coming should there be such a completion setup. The other 2 cases have their completions in less significant zones thus waterflood only sweeps through a smaller portion of the reservoir. Figure 2-39 shows the corresponding zones 4, 5 and 6 where water is moving in the case of upper-completed wells. North view is used because the water front is not well seen from a South perspective. Water movement is contained within the zones it is injected to which explains why one case is more efficient than another.

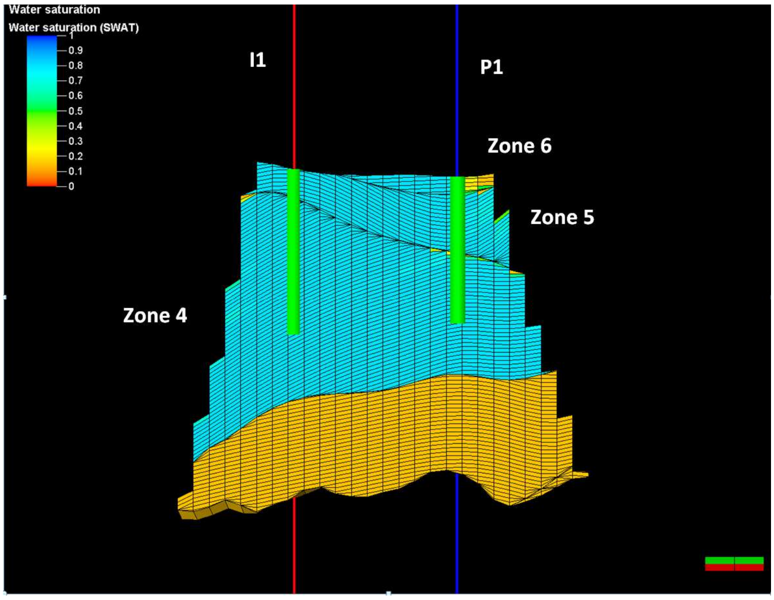


Figure 2-38: Cross section of Pair1 UpperUpper Completion after 5 years (East view)

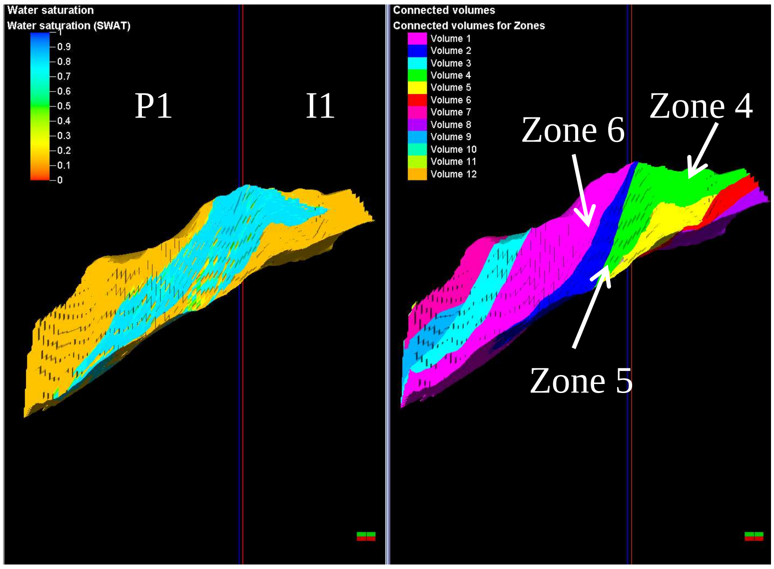


Figure 2-39: Water Saturation of Pair1 UpperUpper Completion after 5 years (North view)

And thus how do these half completion cases compare to full completion? Figure 2-40 presents recovery efficiencies in terms of pore volume injected and it clearly shows that full completion recovers the best amount of oil at 4 pore volumes injected. The area around Pair1 is made up of multiple zones and the wells intersect zones 3, 4, 5 and 6 which mean more volume has been swept than if only certain intervals were completed due to the non-communicating zones. The figure also suggests in an ideal case when full completion is possible one can expect up to 50% recovery with 4 PV of water injection with current favorable rock and fluid properties.

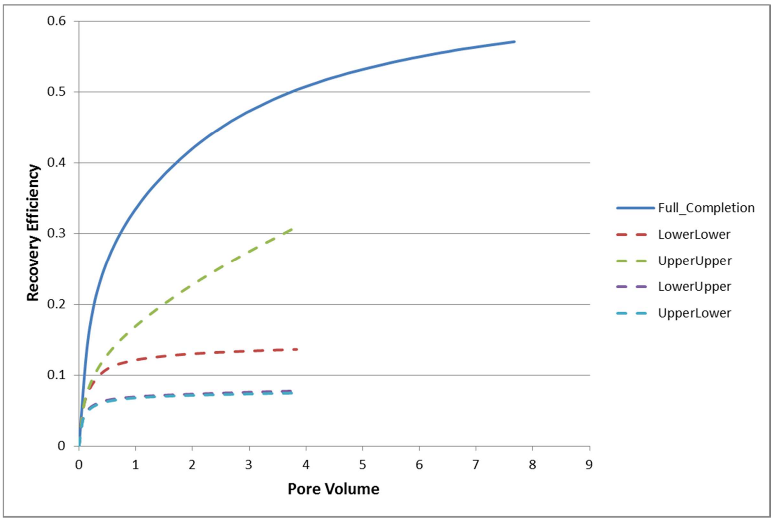


Figure 2-40: Pair1 Full completion and Half Completion.

Pair2 (I2 vs P2):

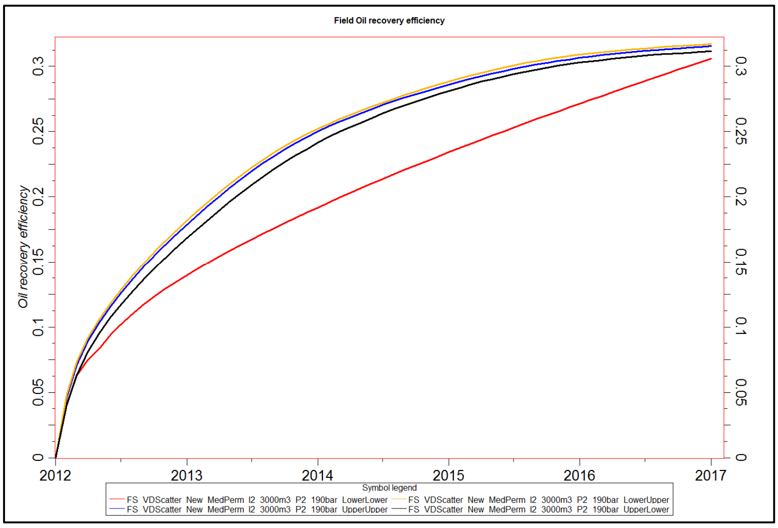


Figure 2-41: Recovery efficiency of Pair2 half completion intervals

Figure 2-41 presents the recovery of four Pair2 completion cases under identical amount of water injection. At a glance, all cases seem to recover roughly the same (30%)

after 5 years of injection. This is due to the fact that I2 and P2 are placed into zones 5 and 6 which make up a significant portion of the area around wells. Water can only move within zones 5 and 6 therefore the swept volume is almost identical for 4 cases. Eventually it reached the point where all the oil in that same volume is recovered resulting in similar simulation results given an injection rate of 37739bbl/day (3000m3/day). A variation in a case where wells are lower-completed being less productive could be that since both wells are operating in the depth in between zones 5 and 6 (Figure 2-42) thus water has a harder time moving from/to wells. The other 3 cases have water flow and/or oil recovered in zone 6 only and they exhibit very similar recovery patterns as a result.

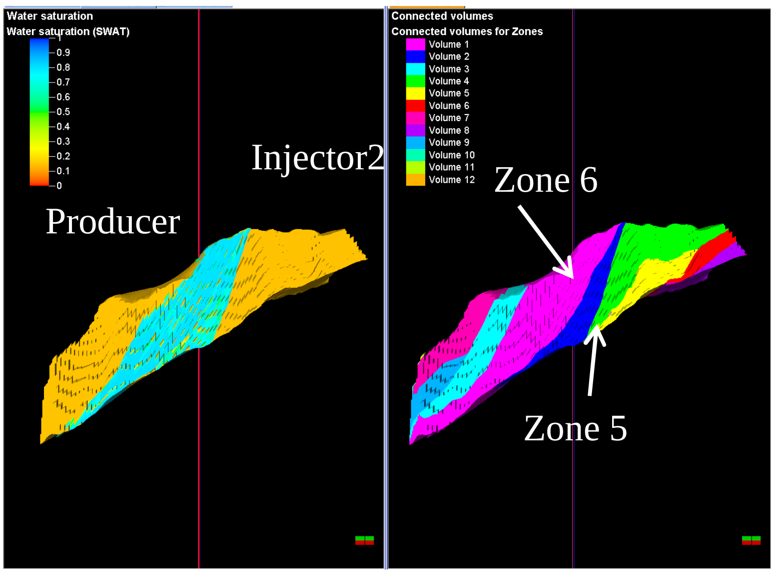


Figure 2-42: Water saturation of Pair2 LowerLower completions in Zones 5 and 6 (North view)

Again it is important to see how half completion intervals compare to full completion which is shown in Figure 2-43. Apparently the full completion case can recover from both Zones 5 and 6 at a rate of 37739bbl/day (6000m3/d). From Figure 2-43 it is observed that at 4 pore volumes injected the full completion case has already reached 37% recovery which is higher than half completion cases. Though this is common, the additional recovered amount is less significant than Pair1 because the area around Pair2 is less complex therefore the completion intervals do not greatly reduce production in this case.

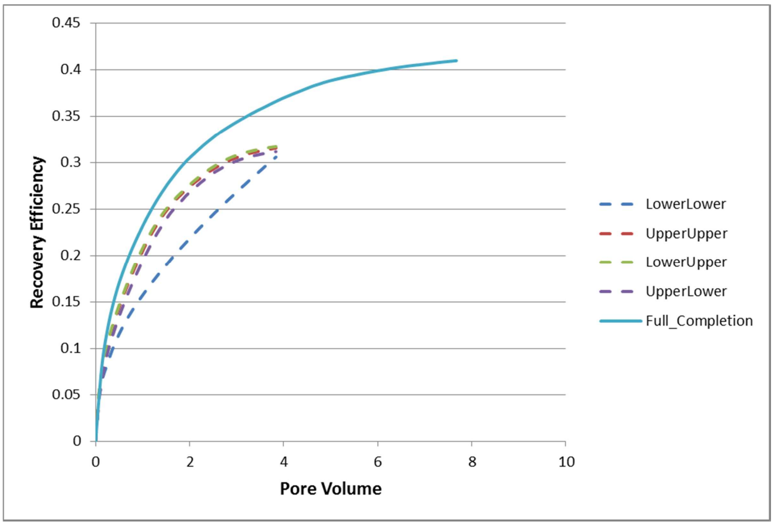


Figure 2-43: Pair2 Full Completion and Half Completion.

Pair3 (I3 versus P3):

Figure 2-44 displays the recovery of Pair3 half completion cases which are all in the 30-ish (%). The highest case (38%) is with upper-completed wells and recovers more because its completions intersect Zones 6 and 7. As for UpperLower completion, the production intervals are only in Zone 6 making it not able to recover from Zone 7. In fact the wells also come into contact with Zone 5 but it is negligible to take into account. The other three cases recover from Zone 6 and therefore have very similar recovery patterns.

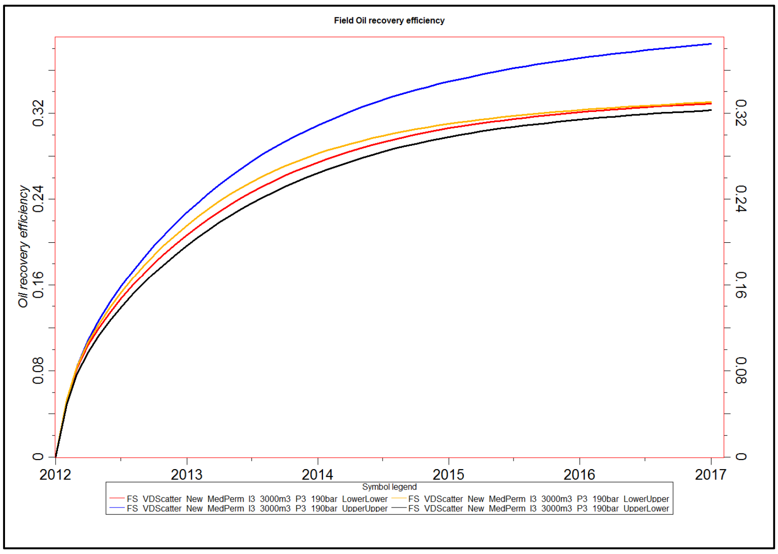


Figure 2-44: Recovery efficiency of Pair3 half completion intervals

Figure 2-45 displays the water front of Pair3 UpperUpper completions (solid blue line) that sweeps through Zones 6 and 7 of the sector model. This explains why this case recovers more oil than the others thanks to the right completion intervals. At this point it gives a new idea of how to best produce this sector model: an injection well does not have to be completed for the full interval but should intersect as many zone interfaces as possible since it will allow water injection to sweep through the most of oil while reducing the costs of completion. Likewise, a production well should intersect the same zones as the injector does and be completed accordingly to receive the oil swept from waterflood. The area around Pair1 makes a great candidate for this purpose should a vertical exploration well be drilled into this section of the reservoir.

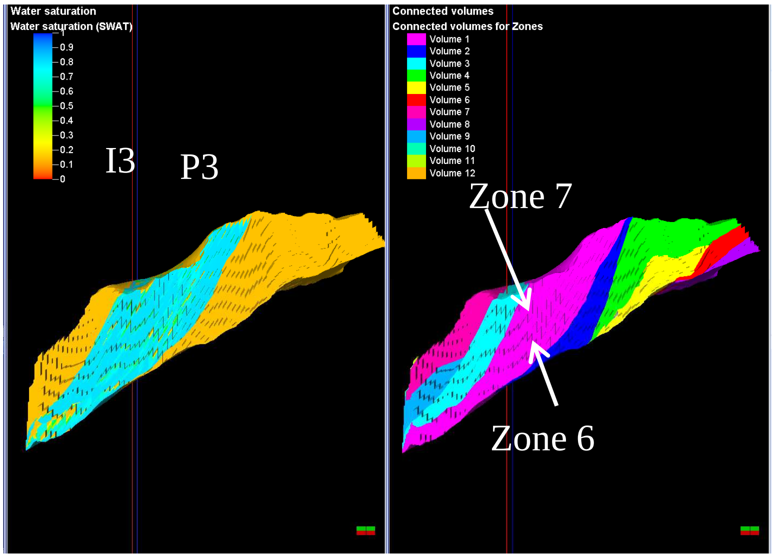


Figure 2-45: Water saturation of Pair3 UpperUpper completions in Zones 6 and 7 (North view)

Pair3 full completion does not perform any better than the UpperUpper completion case (Figure 2-46) because they basically produce from the same zones 6 and 7. At 4 pore volumes injected the full completion case fails to deliver more compared to Pair1 and Pair2. Therefore it may not be a good idea to do full completion in this area. Completion intervals that cross both Zones 6 and 7 should work just as well as a full completion well.

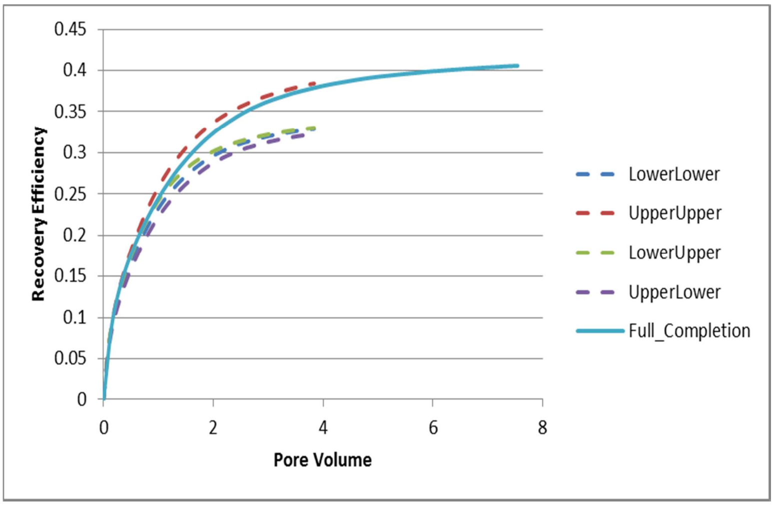


Figure 2-46: Pair3 Full Completion and Half Completion

To explore the other well design for waterflooding on this sector of reservoir, water injection with vertical wells, horizontal wells and vertical wells with lateral completion were examined. Figure 2-47 shows an example of lateral well design to penetrate zones 3 through 8.

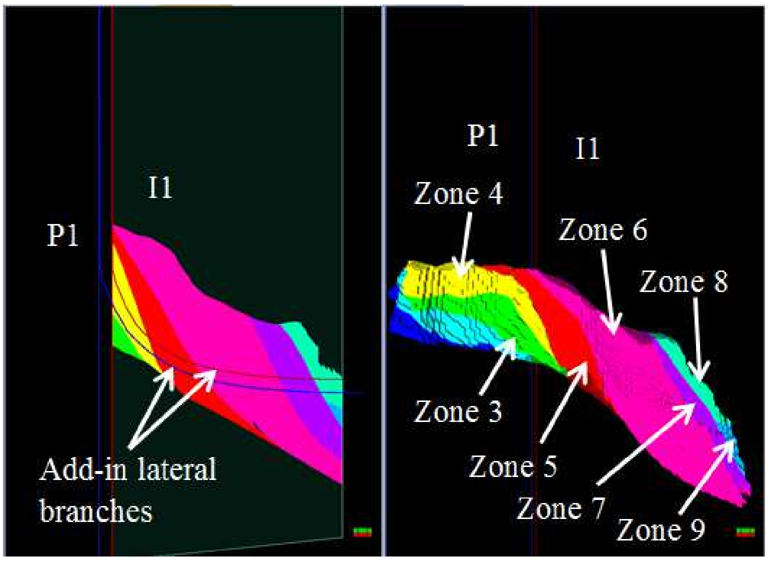


Figure 2-47: Add-in lateral designs for I1 and P1 to gain production from more zones

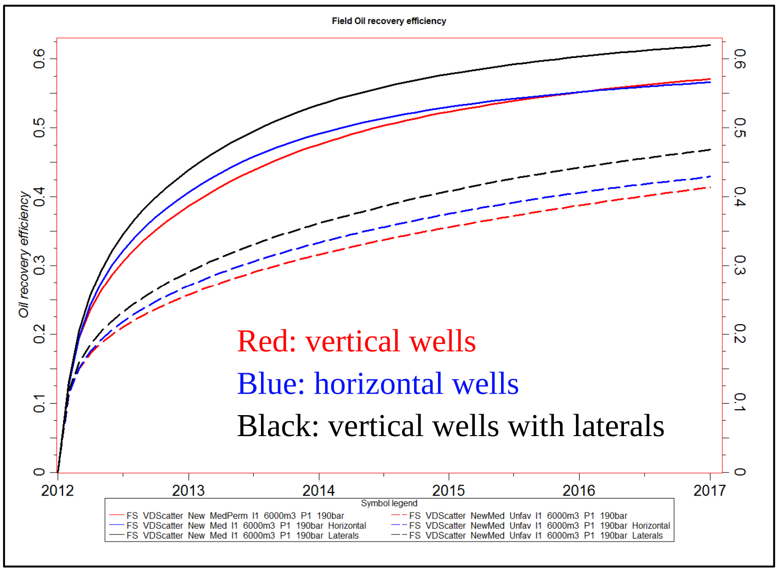


Figure 2-48: Recovery before and after adding laterals, favorable vs unfavorable mobility

Figure 2-48 presents the waterflooding results derived from three well designs which include a case of vertical full completion wells, a case with horizontal injection & production wells and a case with vertical wells plus added lateral branches with open hole completion (see Figure 2-49). It indicates that having a lateral branch to I1 and P1, additional 5% recovery was gained as compared to that from the other well designs. Similar trends were also observed when unfavorable mobility ratios were applied in fluid properties design. The vertical wells produce least and wells with added lateral branches produce the most though the additional amount is not so significant.

Figure 2-49 also explains the 5% increase in recovery of Horizontal compared to Laterals mainly comes from Zone 3 where the vertical portions of I1 and P1 intersect. After 5 years of injection hardly any part of Zone 3 was flooded with the Horizontal well case while water entered and displaced oil in the case of vertical wells with an added lateral branch.

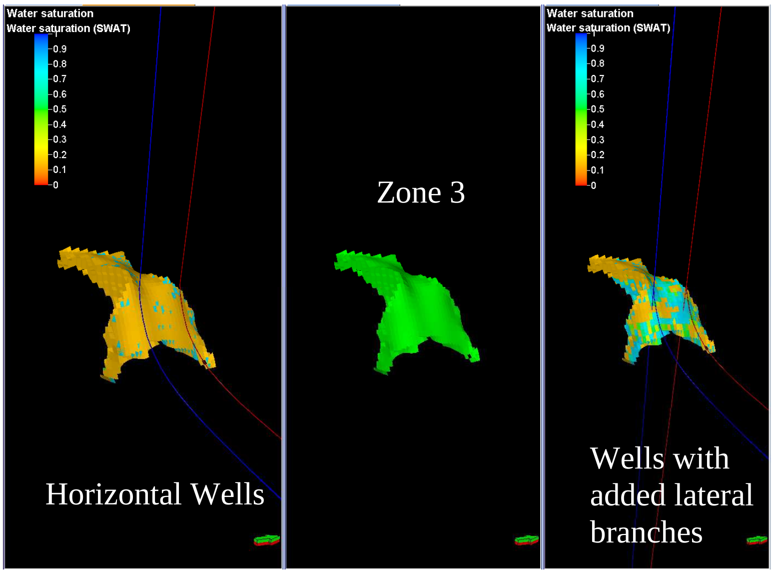


Figure 2-49: Additional production from zone 3 after 5 years of production

2.3.2. Simulation Gridding

From TCC upscaling study, DS3 detailed static model is the next step and provides the size and complexity for simulation gridding. The workflow is (1) scale up the structure laterally or vertically and (2) sample property models into coarsened grid. While step (1) is a predefined and straightforward process in the modeling package, step (2) involves tuning sampling methods to best match initial model performance.

2.3.2.1. Lateral Coarsening

DS3 model initially has 10x10(m) grid blocks and is intended to have a new resolution of 20x20(m) in the coarsened model. The outcome of this process has been something unexpected: the scaled up grid is drastically altered and fails to retain the pinch-out cells both on top and at layers where there is an erosion surface between them. Figure 2-50 reveals how the scaled up model differs from original structure and where cells are discarded. The water saturation displayed results from a waterflood study of one injector and producer on the updip side of DS3, with injection rate being 37739bbl/day (6000m3/day) and production BHP control at 2700psi (190bar). Favorable fluid mobility ratios and drainage process are also implemented in this study.

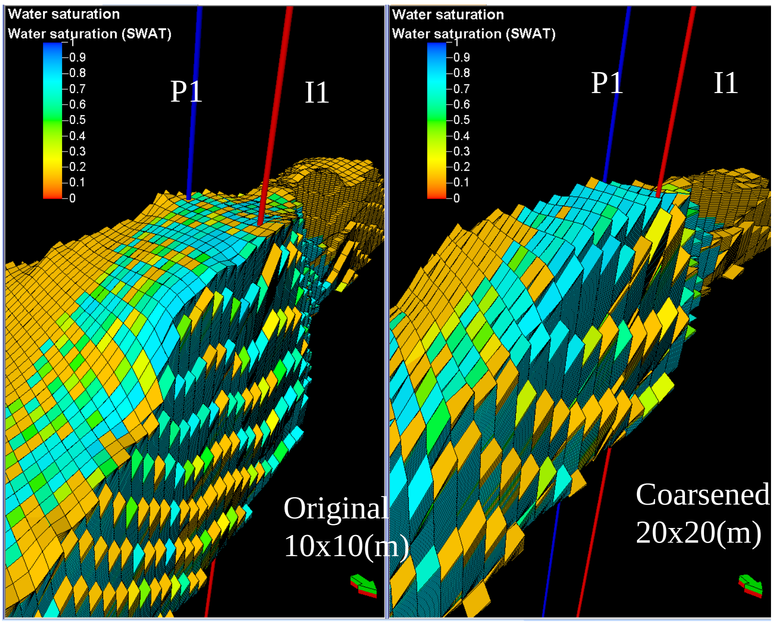


Figure 2-50: Original Model versus Scaled Up Grid

Figure 2-51 shows that the 20x20(m) grid (dash line) does not match recovery performance generated in the case of 10x10(m) grid (red solid line). Increasing the exponent factor of Power averaging improves the match slightly but fail to completely match.

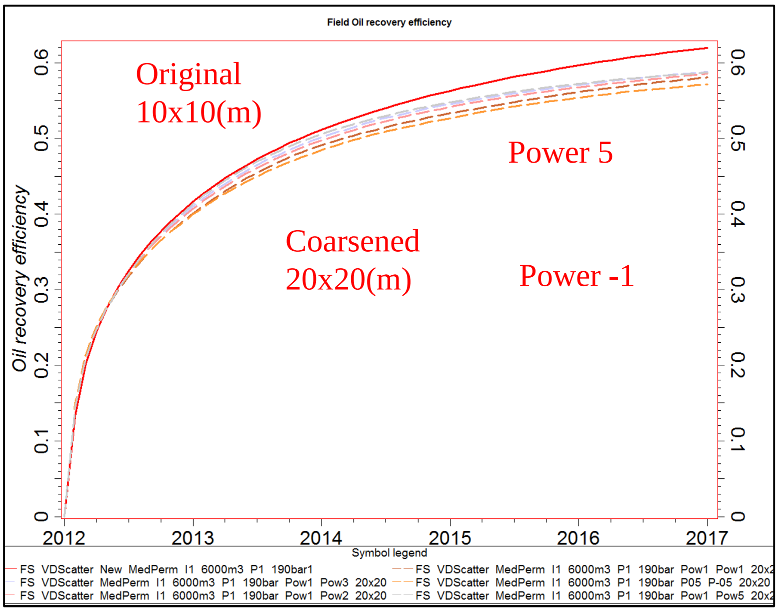


Figure 2-51: Simulation Results of 20x20(m) Grid versus Original Model

In addition, 20x20(m) lateral coarsening failed to preserve the model geometry and lost the pore volume by 15% suggests difficulty of upcaling laterally when the model geometry cannot be preserved. Other resolutions 30x30 (m) has also been attempted without any further improvement.

2.3.2.2. Vertical Coarsening

Figure 2-52 displays water saturation distributions at the end of five years of water injection for upscaling vertically with grid thickness varied in 0.5m (original), 1m, 2m, and 4m. A pair of production and injection wells on the topmost area of DS3 is configured with injection rate at 37739bbl/day (6000m3/day) and production BHP control at 190bar. Simulations were performed on 1, 2 and 4m thickness grids and the results are compared and shown on Figure 2-53.

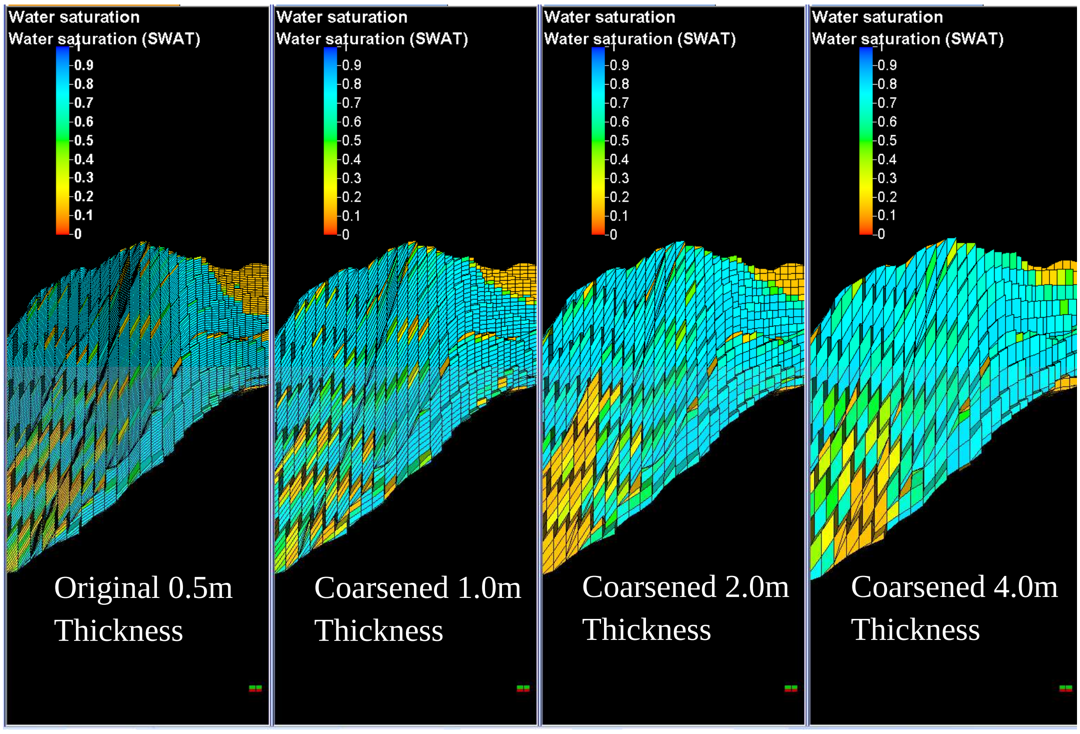


Figure 2-52: Water Saturation of Original and Coarsened Models

Figure 2-53 displays simulation results for 1m, 2m and 4m thickness scenarios versus original case. From the figure, 1m and 2m thickness grids (blue and black dashed lines) are matched using Power 1 (Arithmetic) sampling method for porosity and Power 2 (RMS) sampling method for permeability. On the other hand, the results from 4m thickness grid (pink and green dashed lines) fail to match original fine model with different tuning methods. This practice shows the cell thickness of the original fine model can be scaled up to 2m thickness with the proposed method and retain the reservoir heterogeneity in addition to reduction of the computation time by as much as three times.

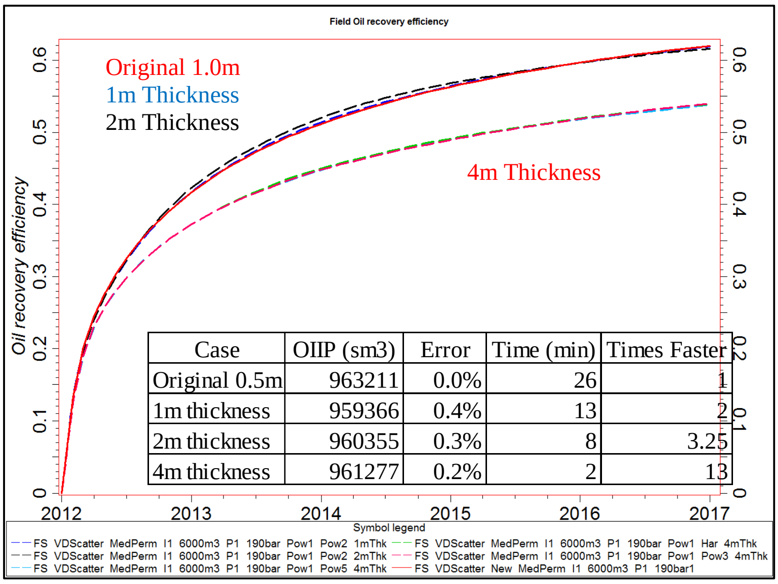


Figure 2-53: Comparison of 1m, 2m and 4m Thickness Grids versus Original 0.5m

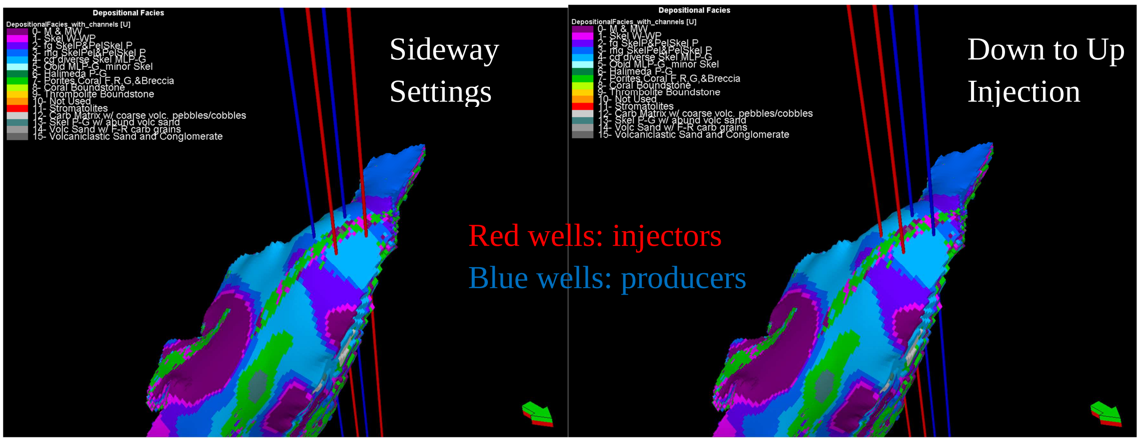
2.4. Megabreccia/Heterozoan Reservoir Systems (DS2 & DS1)

DS2 and DS1 are at the bottom of La Molata model and above the volcanic basement. These units are briefly studied for waterflood and the correlation between recovery and facies distribution. This opens up new possibility for later research into these systems.

2.4.1. Megabreccia Cycle Reservoir System (DS2)

DS2 consists of two stratigraphic units of breccia associated with grainy carbonate facies which is mostly analogous to slope carbonate reservoirs in the Permian of West Texas and New Mexico. The questions for this unit include: Given the heterogeneity of the Megabreccia reservoir system, is it a reservoir? Is vertical well adequate to produce it?

To examine the effect of well placement and diagenetic scenarios, Figure 2-54 displays two well scenarios used to study waterflood in DS2. The first scenario (a) involves injecting from the side across the Breccia channel. The second scenario (b) injects water from the lower end of the reservoir toward the updip side. Distance between injector and producer is approximately 100m. A pressure gradient of 0.23bar/m is setup between each pair of injector and producer.



(a) (b)

Figure 2-54: DS2 Facies Distribution and Well Settings

Figure 2-55 shows the recovery of four cases with Variable Dolomite Scatter and No Scatter, favorable mobility ratios, sideway injection and down to updip injection versus PV injected. The highest recovery is about 13% with more than 0.5 PV injection. Permeability with Scatter shows limited effect in each well design. Sideway injection obviously has a better recovery for the same amount of water flood. For example at 0.35 PV injected the best of Down to Up yields roughly 5% compared to 10% from Sideway injection.

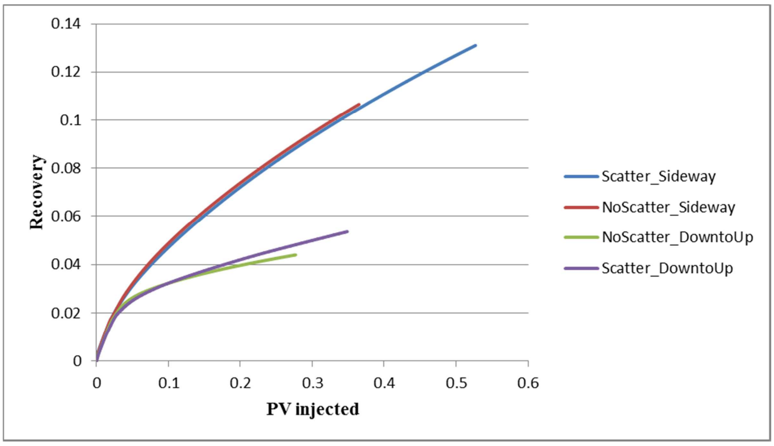


Figure 2-55: Recovery versus Pore Volume Injected after 5 Years

2.4.2. Heterozoan Reservoir System (DS1)

DS1 consists of stratigraphic units that onlap against sloping topography on volcanic basement. DS1B is mostly analogous to discoveries in Venezuela Perla giant gas field. The question is: Given the nature of onlapping heterozoan cycles, will a vertical well drilled into the proximal point of onlap effectively produce the entire section? DS1 is at the bottom and the last unit of La Molata model.

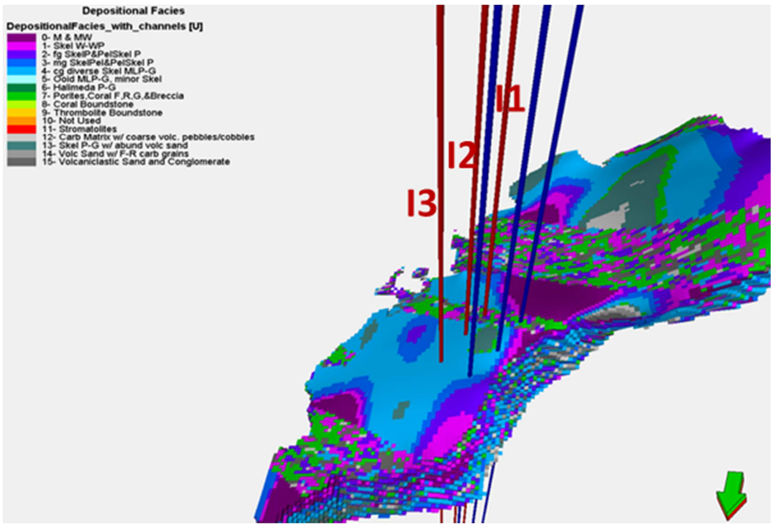


Figure 2-56: DS1 Facies Distribution and Well Locations

Figure 2-56 displays six wells that are planned close by the point of onlap for waterflood study. Three red wells are injectors and the other blue ones are producers. A pressure gradient of 0.13bar/m is defined in between the injection and production wells for pressure maintenance. Simulation is carried out for 5 years of injection and the results are examined to identify areas where oil is left behind.

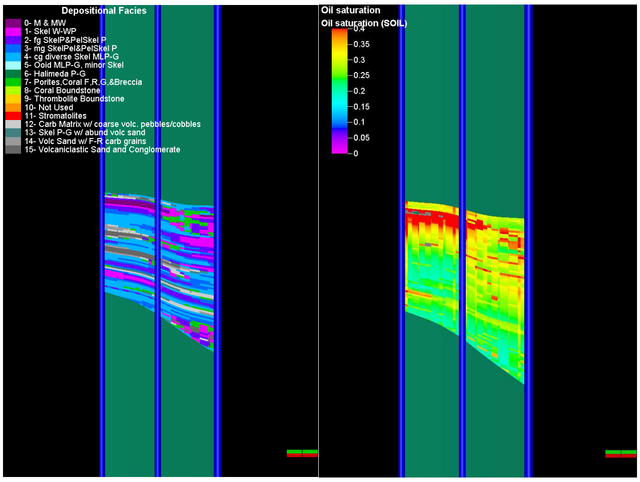


Figure 2-57: Oil left behind after 5 years of injection

Figure 2-57: Some of the oil left behind is observed at the cross section between the three producers P1, P2 and P3. Most of it corresponds to 0-Mudstone and muddy wackestone (dark purple), 1-Skeletal wackestone and packstone (pink), 3-Medium-grained skeletal/peloidal packstone and peloidal/skeletal packstone (blue). These areas are where other recovery mechanisms can help improve areal displacement.

2.5. Summary

TCC study finds there are 3 main sequence boundaries in the model. Figure 2-58 shows that the one on top is the most continuous while two others are not as continuous. Sequence boundaries make it more difficult for cross flow in the upper portion of TCC and some parts of the lower area. Even though they are thin, they play a role in slowing down and/or keeping water injection from the production well.

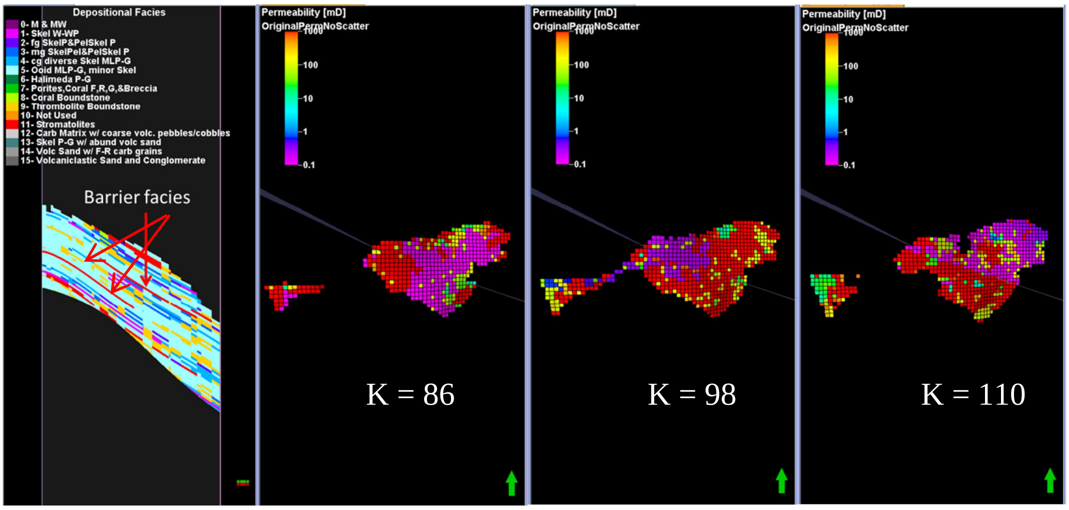


Figure 2-58: Three Sequence Boundaries in TCC Unit and Their Distribution

There are 3 geologic scenarios of interest which include Base Case, Rank Transformed and Variable Dolomite. Mobility ratios between displacing phase (water) and displaced fluid (oil) have a significant impact on areal displacement. Producer on the higher ground of TCC yields better results versus on the down-dip side wherein the gravity and cross flow mechanism improve sweep efficiency during the displacement. Full range completion is not essential for TCC since it yield very slight difference compared to half completion intervals. Consequently half completions can be utilized to produce from a pay zone should this one be a real subsurface reservoir. Well pattern study suggests that the additional investment in water injection for 9-spot is not beneficial compared to 5-spot. Regular and inverted 5-spot patterns bring more return on investment in comparison with their 9-spot counterparts.

The layering process needs to capture where low-permeability barriers are so that complexity can be retained by only coarsening the more flow conductive areas. Barriers like those in TCC may be thin but play a vital role in the recovery process and should be represented in the model. TCC cell thickness should be scaled up to 2(m) thickness at most. As for lateral gridding, further validation is needed for various sampling methods. Tuning porosity could have much more impact on recovery before breakthrough (OIIP in particular) while permeability tends to affect recovery after water breakthrough occurs.

For DS3, preliminary results show vertical wells drilled along strikes will have most of the oil left behind at the bottom where there is facies associated with low permeability. A well drilled updip would be able to recover up to 60% (Figure 2-33) of the updip area given Variable Dolomite, pressure support and favorable mobility ratios. This is because Variable Dolomite (No Scatter) has the most cells with permeability higher than 100mD (Figure 2-33). The lowest estimate of recovery is about 36% with Rank Transformed and unfavorable mobility ratios. Permeability with Scatter has very limited effect on the recovery of DS3 on the updip. The scenario in which there are erosion surfaces gives an opportunity to look at DS3 from a different perspective. In such cases, drilling design needs to focus more on exposing the wells to as many zones as possible for better recovery. The optimal design for this scenario is having vertical wells with laterals since they would intersect the most number of zones.

Simulation gridding study finds that lateral coarsening is not the best approach to preserve reservoir geometry and heterogeneity. Lateral coarsening fails to retain cell pinch-outs which greatly alters the grid shape. It also cannot match the initial model performance. This is mainly because the number of cells is reduced at least four times (10x10m to 20x20m). Lateral coarsening is not recommended for DS3. Vertical coarsening examines various cell thicknesses for flow modeling and observes that DS3 can be scaled up vertically to 2m cell thickness and is still able to reproduce 0.5m (original) cell thickness model.

Chapter 3: Agua Amarga Scale-Up Study

Introduction

Chapter 3 discusses upscaling the Agua Amarga facies model to observe the impact on its connected volumes. The questions are how much change there will be for the top five connected volumes after being scaled up and whether they will be grouped into one. The facies is scaled up vertically, laterally, and both vertically and laterally. Coarsening also includes merging adjacent zones from top to bottom of the stratigraphic table with both reservoir and baffle units.

3.1. Petrel 3D Model

The Petrel 3D model was constructed with facies property modeling by Dvoretsky *et al.* Based on observation from the field, there are two facies units defined in this study: baffle and reservoir. Baffle units include low-density hemipelagic-pelagic foraminiferal wacke-stone pack-stone, volcanic foraminiferal wacke-stone pack-stone and skeletal foraminiferal wacke-stone pack-stone facies that serve as a barrier between layers and are coded 2, 3, and 4 in the model. Reservoir units consisting of 3 graded fine to very coarse skeletal pack-stone facies and 3 breccia from fine to very coarse matrix facies are of reservoir quality and mainly the interest of this study. They are coded from 5 to 10 in the model (Table 3-1).

Facies	Depositional Mechanism	Petrel™ Model	Facies Integer	Color
Foraminiferal WS-PS	Hemipelagic-pelagic sedimentation	Baffle units	2	
Volcanic foraminiferal WS-PS	Hemipelagic-pelagic sedimentation or low-density turbidity currents		3	
Skeletal foraminiferal WS-PS	Low-density turbidity currents		4	
Graded fine-medium skeletal PS	High-density turbidity currents	Reservoir units	5	
Graded coarse skeletal PS			6	
Graded very coarse skeletal PS			7	
Breccia: fine matrix	Debris flows		8	
Breccia: medium matrix			9	
Breccia: coarse-very coarse matrix			10	

Table 3-1: Baffle and Reservoir Units in the 3D Petrel Model (Dvoretsky *et al.* 2012)

Previous work indicated that connected volumes were generated from reservoir units in the facies model and each separate unit would be a connected volume on its own. Then it was assumed that if two volumes were in contact with one another they would connect as well and behave as one reservoir. With some adjustment to Petrel workflow and the top 5 connected volumes were generated using this approach in Scenario 1 (Figure 4-2). “The first scenario assumes that debrites and high-density turbidite facies are capable of flow communication and, where cells are in contact, behave as a continuous reservoir” (Dvoretsky *et al.* 2012). The color of each volume in Figure 4-2 is assigned based on its size from large to small: red, orange, yellow, green and blue. The largest connected volume (red) is from the focused-flow system and consists of reservoir facies that become thinner away from proximal paleovalley locations (Dvoretsky *et al.* 2012) while the remaining four largest connected volumes occur within the dispersed-flow system.

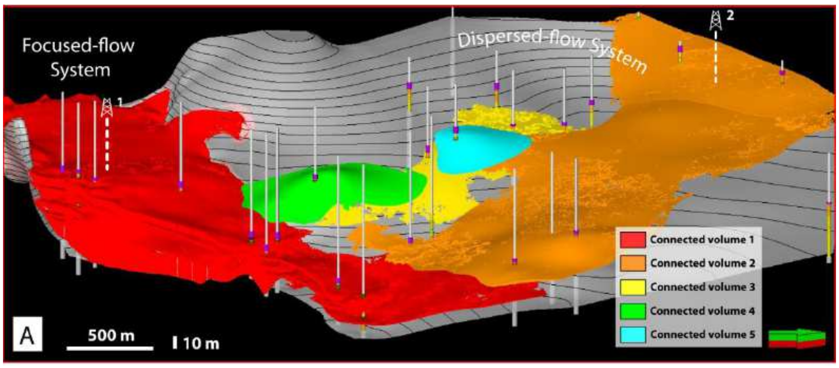


Figure 3-1: Scenario 1 with Top 5 Connected Volumes (Dvoretsky *et al.* 2012)

3.2. Methodology

This research implements commercial upscaling software package in Petrel as a tool to demonstrate the fact that typical scale up workflow in Petrel may cause significant loss of geology features if used without guidance from what is known from the field.

Initial lateral grid resolution of the model is 5x5(m) and cell thickness is inversely proportional to the number of layers in a zone. At this point the purpose is to examine the effects of lateral, vertical coarsening and both of them combined. The model is first scaled up laterally to 10x10, 15x15 and 30x30(m). The process includes both structure and property (facies in this case) and then connected volumes are built from new facies distribution. This is to make sure connected volumes are consistent with their corresponding facies. Once this is done, next step is to scale up the model on the vertical scale.

To carry out vertical coarsening, a sensitivity analysis workflow is set up with 2 steps. Each of them involves merging either 2 or 3 adjacent zones at one time from top to bottom stratigraphicaly and layers being coarsened in the new combination. By doing this, the attempt was made to replicate a process in which conventional workflows may go through without having sufficient amount of data to justify the merging. As there are 21 zones of interest in the model (top and basement not included), the number of attempted cases for step 1 is 20 and step 2 is 19. For most cases, number of layers in the newly merged zone is half of the total ones from contributing zones. For example, if two/three zones were combined and total number of layers is 9, layering in the new zone would be down to five. While lateral resolution remains 5x5(m), it will allow one to observe the impact of vertical coarsening by itself from one case to the other.

Zone	Layers	Note
JUNK (0)	1	
Unit 7: fine	1	Baffle
Unit 7: E10	2	
Unit 6: fine_b	2	Baffle
Unit 6: E9	3	
Unit 6: fine_a	2	Baffle
Unit 6: E8	3	
Unit 5: fine_c	2	Baffle
Unit 5: E7	1	
Unit 5: fine_b	4	Baffle
Unit 5: E6	2	
Unit 5: fine_a	2	Baffle
Unit 5: E5	2	
Unit 4: fine_d	4	Baffle
Unit 4: E4	2	
Unit 4: fine_c	1	Baffle
Unit 4: E3	1	
Unit 4: fine_b	1	Baffle
Unit 4: E2	2	
Unit 4: fine_a	1	Baffle
Unit 4: E1	2	
Unit 3	6	
Unit 1	8	

Table 3-2: Petrel 3D Model Stratigraphy

After that both lateral and vertical coarsening is applied at the same time to observe their combined effects on facies distribution, particularly reservoir and baffle units. Connected volumes are generated after each scale-up run using a workflow developed by Dvoretsky *et al.*

(1) filtering out baffle units from facies property (Figure 3-2)

(2) building the first-step connected volumes (Figure 3-3)

(3) filtering these volumes down to 30 (Figure 3-4)

(4) assigning "1" to be the value of all the cells (Figure 3-5)

(5) generating the final volumes based on the volumes property that has "1" as its value (Figure 3-6)

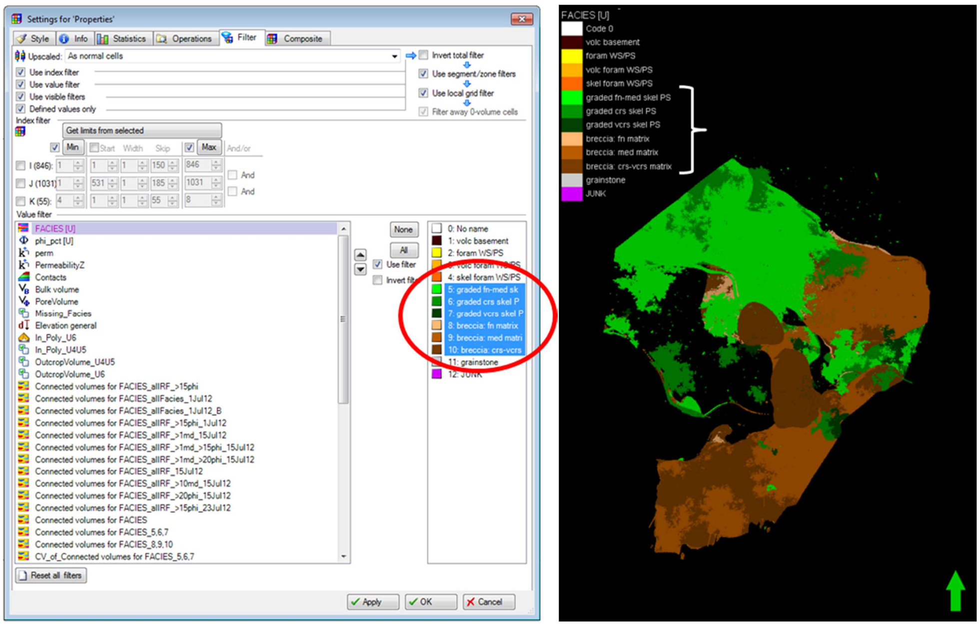


Figure 3-2: Filtering out baffle units from initial facies property

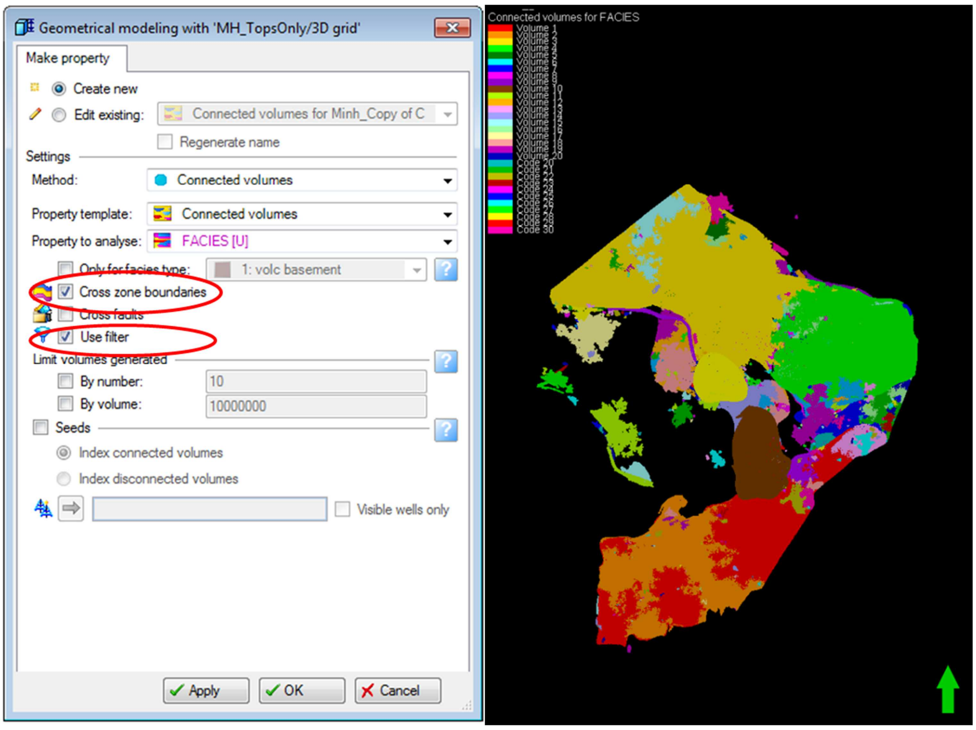


Figure 3-3: Building the first-step connected volumes

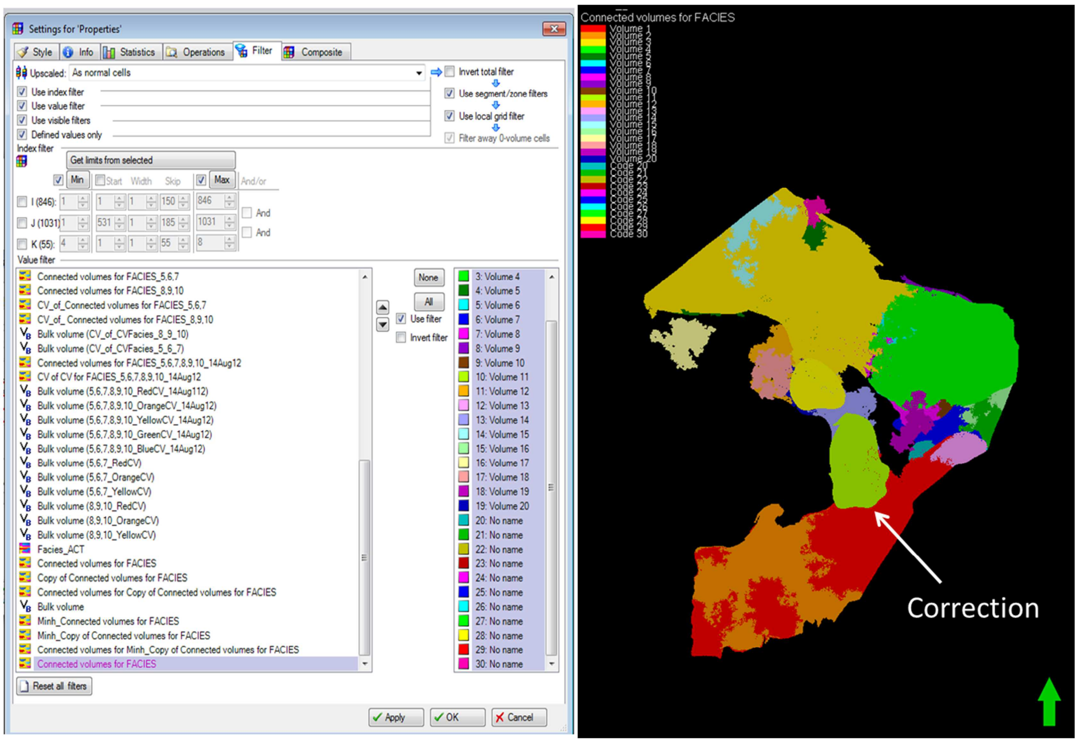


Figure 3-4: Filtering first-step connected volumes down to top 30

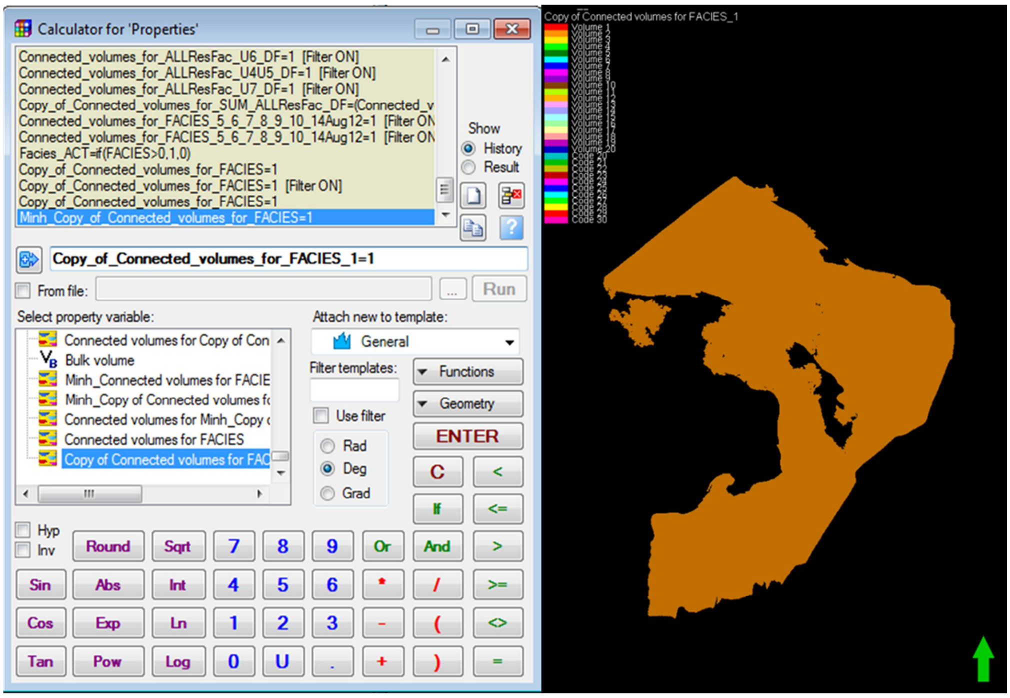


Figure 3-5: Assigning “1” to be the value of all the cells

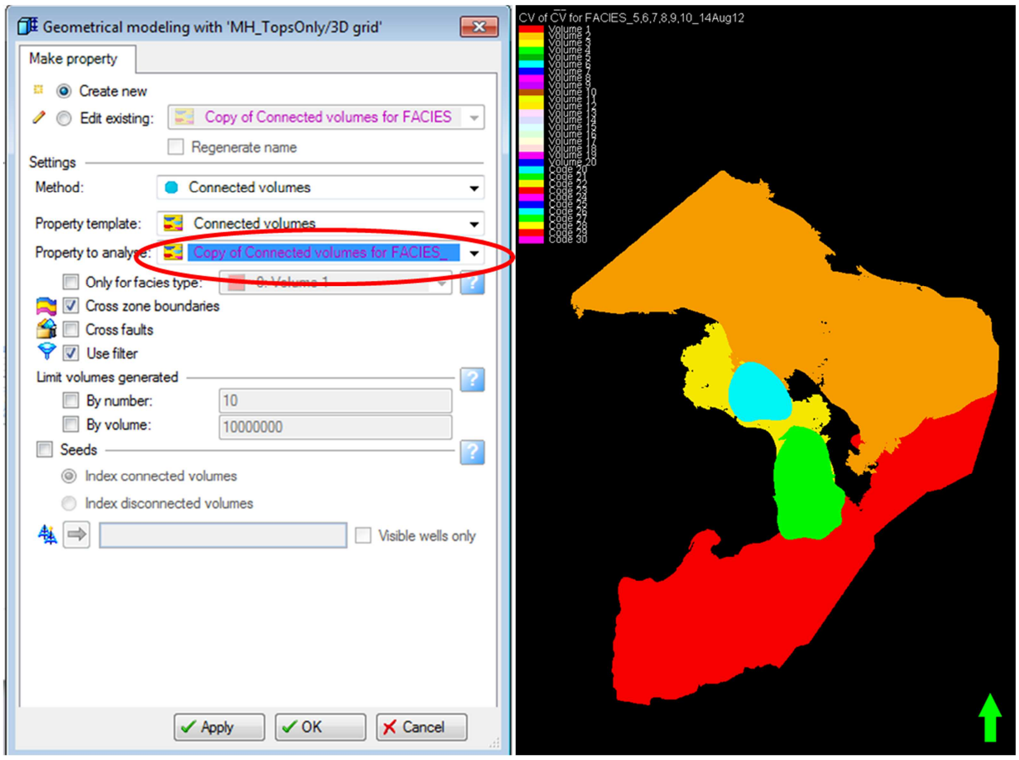


Figure 3-6: Generating final volumes based on the volumes property that has “1” as its value

When (2) is initiated, Petrel will turn each group (cells that are geometrically in contact with one another) of the same reservoir facies code into a connected volume, and there are more than a thousands of such volumes ranging from large to very tiny ones. Since it has been assumed in Scenario 1 that when cells are in contact they would allow communication and behave as one reservoir body, significant volumes are grouped into larger potential reservoirs and smaller ones are discarded to remain focused on what could possibly represent subsurface formations. Note that Dvoretsky decided to filter the first thousand-ish connected volumes down to an arbitrary number of 30 after (2) is done. This same technique is incorporated to all of the modeling work assuming this is how a static subsurface model would be handled. Some seemingly insignificant volumes, however, play a key role in connecting large chunks of the top 5 volumes in the final model because of where they are located. Keeping this in mind helps explain the disintegration and/or redistribution of top 5 connected volumes.

3.3. Results and Discussion

3.3.1. Lateral Coarsening

Agua Amarga model was initially gridded at 5x5(m) and has been coarsened to 10x10, 15x15 and 30x30(m) in this study. Using Global grid coarsening process in Petrel helps define new lateral grid resolution and can be an alternative to Pillar gridding since the Fault model is missing. Scaled up 10x10 grid model (Figure 3-7) shows the largest Red Volume splits up into smaller ones due to filter effects.

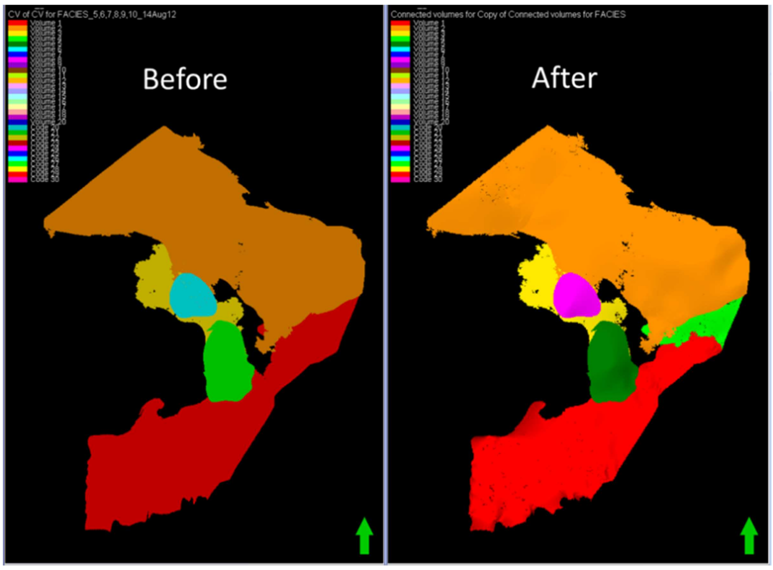


Figure 3-7: Original 5x5(m) grid versus Scaled up 10x10(m) grid

The 15x15(m) grid also displays similar patterns with Red Volume as it is no longer one large chunk of reservoir facies but broken into separate volumes (Figure 3-8). The correction step taken during coarsening has to do with this change as it filters the first-generated connected volumes down to 30. This means only these 30 volumes will be grouped with one another to create top 5 volumes in the original model. Some smaller volumes that connect portions of a larger volume therefore have been taken out and the larger volume is disconnected itself. The problem is the large number of first-generated small volumes makes it hard to know which one to be filtered out and which not to be. Initially it was planned to follow Dvoretsky's workflow to regenerate connected volumes once facies property is scaled up, including filtering connected volumes down to top 30. As this inconsistency is observed between the original and scaled up models, appropriate adjustment would have to be made in regard to which small volumes need to be filtered to maintain the connectivity of each volume itself while applying geologic information obtained from the field.

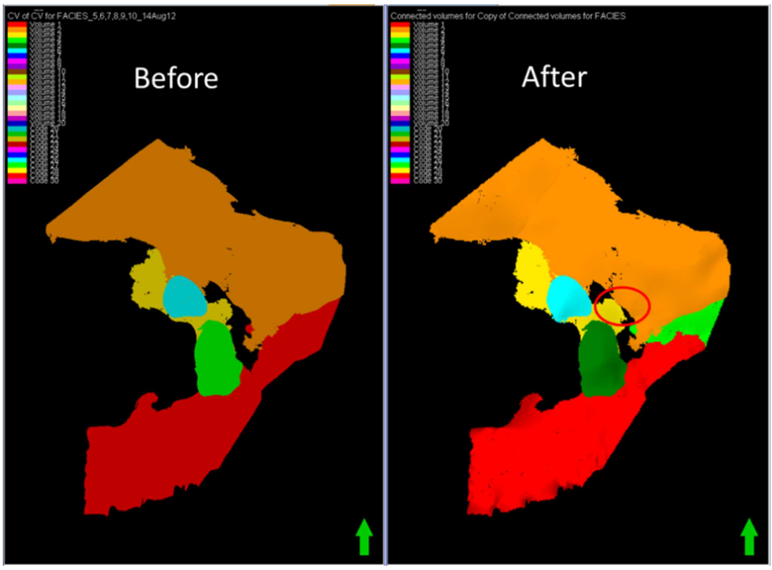


Figure 3-8: Original 5x5(m) grid versus Scaled up 15x15(m) grid

On the other hand, the 30x30 grid (Figure 3-9) shows the least change because some cells in Red Volume did not get filtered out during the correction step. This results from the fact that top 30 volumes now cover more volume than those with 10x10 and 15x15 grid resolution and thus retain their connectivity better. Thus far only the effects of coarsening workflow on top five connected volumes have been discussed and the following section will cover changes when reservoir and baffle units are combined.

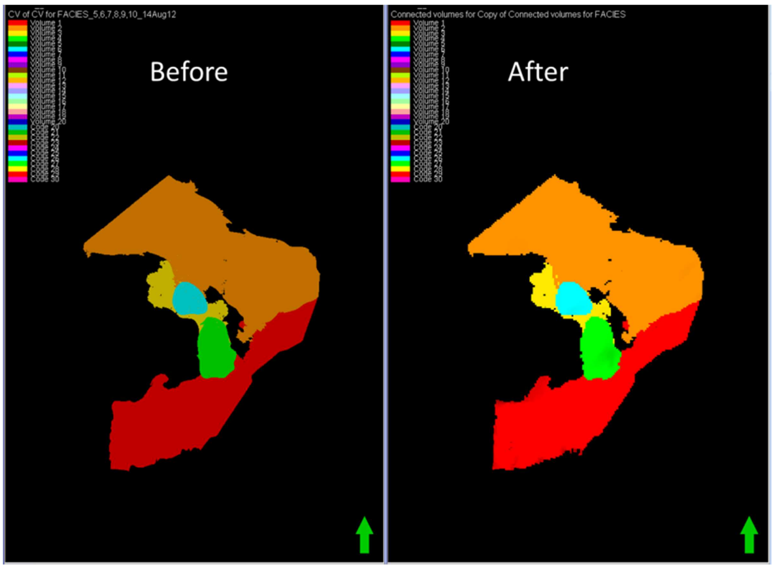


Figure 3-9: Original 5x5(m) grid versus Scaled up 30x30(m) grid

3.3.2. Vertical Coarsening

The 2-step sensitivity analysis workflow consists of merging adjacent zones from top to bottom stratigraphicaly to investigate any impact it may have when a baffle facies zone is averaged with an adjacent reservoir-facies one. Step 1 was designated to merge two adjacent zones whereas step 2 three adjacent zones at one time. Due to the reservoir alternating baffle nature of Agua Amarga model, it is almost always the case where a baffle zone merges with another mainly reservoir facies zone.

Step 1: 20 merging runs were performed and only cases (2, 12 and 20) that display a significant modification in various volumes would be discussed (Figure 3-10).

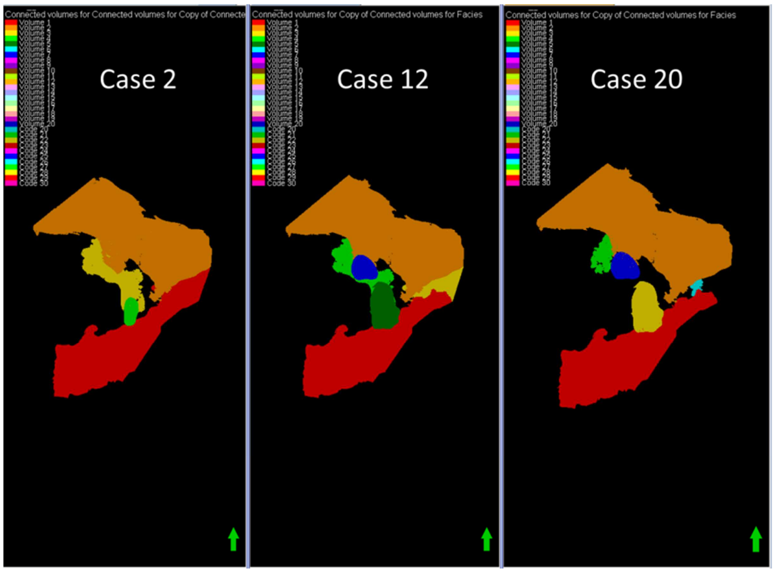


Figure 3-10: Comparison of Case 2, 12 and 20

Case 2 (Figure 3-11 & 4-12) is when ‘Unit 7: E10’ and ‘Unit 6: fine_b’ are merged. Total number of layers from the 2 zones is 4 and number of layers in new zone is 2. What can be observed is the fifth largest volume (Blue) is completely taken out while the fourth largest (Green) is reduced in size. As one compares the two zones and merged one, they would find that reservoir units in ‘Unit 7: E10’ have been averaged with baffle from ‘Unit 6: fine_b’ and the results are what is seen from the corresponding connected volumes.

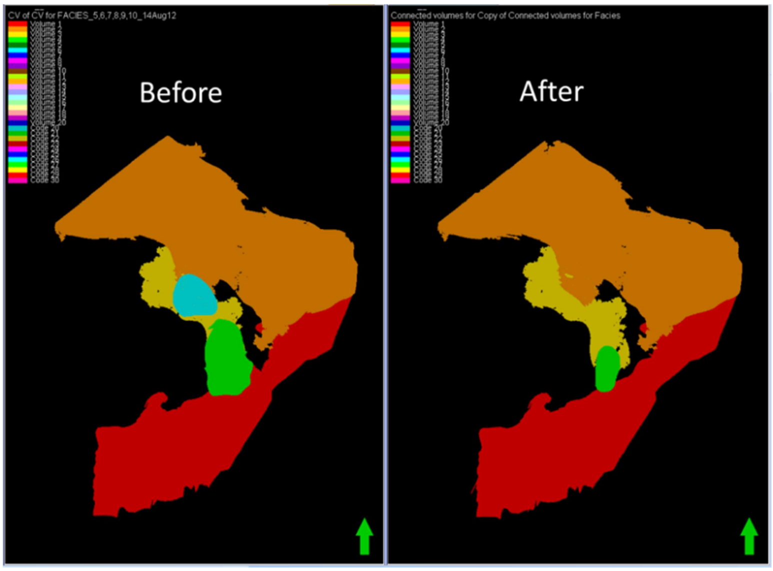


Figure 3-11: Step 1 Case 2

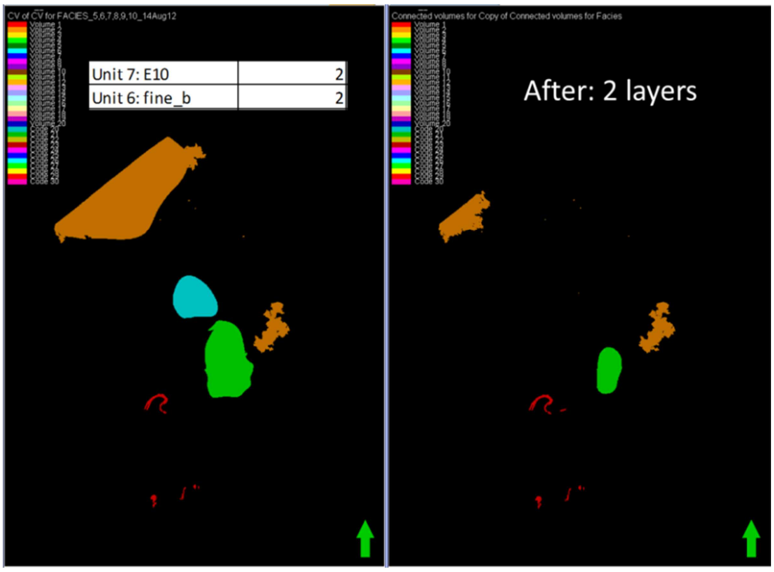


Figure 3-12: Step 1 Case 2 – Zone to zone comparison

Case 12 (Figure 3-13 & 3-14): ‘Unit 5: E5’ and ‘Unit 4: fine_d’. Total number of layers is six from contributing zones and three in the merged zone. The largest red volume breaks down to two smaller ones with this setup. Again, there are small cells in between Red and Yellow after upscaling that have been filtered out therefore there are now two connected volumes instead of one big red. It is also noticed as Petrel assigns color to each volume based on its size, the order in which top 5 volumes were set up will not always be guaranteed when there are more or less volumes in the model. It is also observed some portions of the second and third largest volumes have seen merging effects when comparing the zones before and after scaling up has been done.

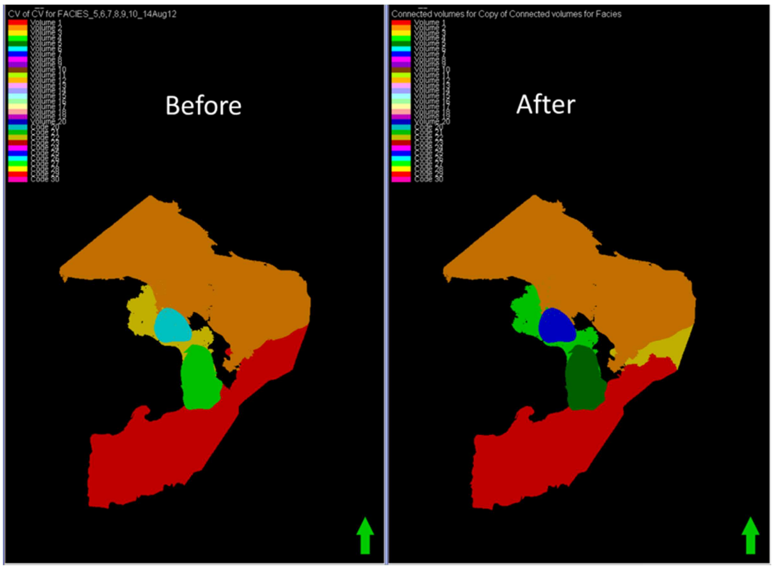


Figure 3-13: Step 1 Case 12

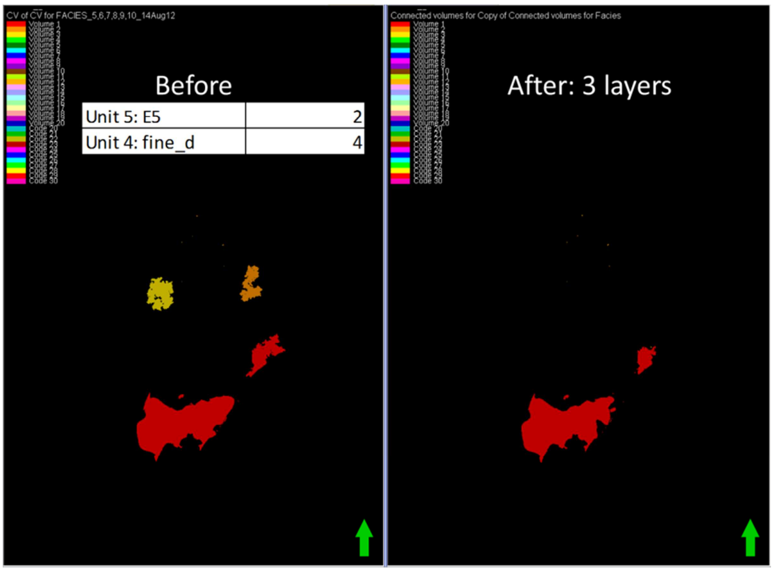


Figure 3-14: Step 1 Case 12 – Zone to zone comparison

Case 20 (Figure 3-15 & 4-16): ‘Unit 4: E1’ and ‘Unit 3’. Total number of layers is 8 from the two zones and 4 in the merged zone. Vertical resolution is reduced significantly which leads to some of the volumes shrink and break down due to the filter used to clean up smaller connected volumes. Color assignments among the volumes also change since there are more small volumes than before scaling up. Zone-to-zone comparison shows the largest and third largest volumes are most severely affected by averaging reservoir with baffle facies.

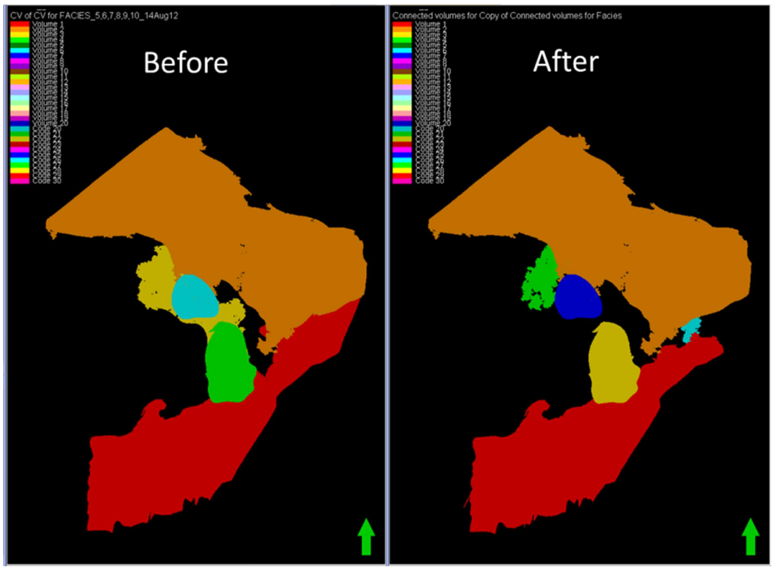


Figure 3-15: Step 1 Case 20

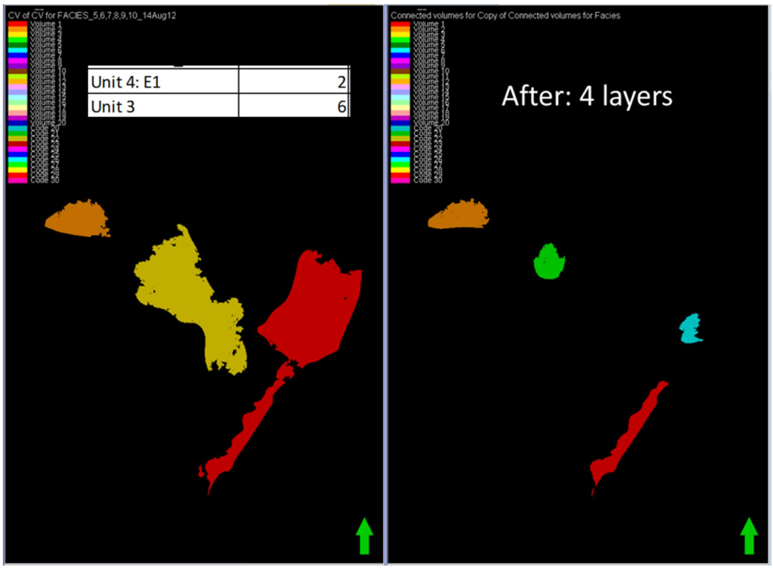


Figure 3-16: Step 1 Case 20 – Zone to zone comparison

Step 2: Cases that display the most noticeable change are 1, 4 and 19

Case 1 (Figure 3-17 & 3-18): ‘Unit 7: fine’, ‘Unit 7: E10’ and ‘Unit 6: fine_b’. Total number of layers is 5 from contributing zones and 3 in the merged zone. As it can be observed, part of the fourth largest volume (Green) shrinks and so does the fifth largest volume (Blue) because this indicates there is another volume that is larger than dark green in the after scaling picture that shows up in the model. The reason that volume is not seen is because it has been taken out. Baffle units typically dominate during merging 3 zones which results in reduction of connected volumes.

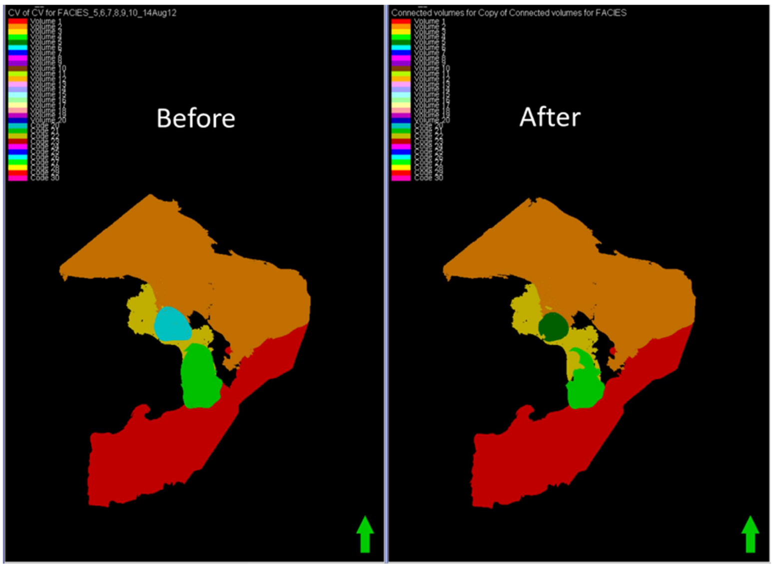


Figure 3-17: Step 2 Case 1

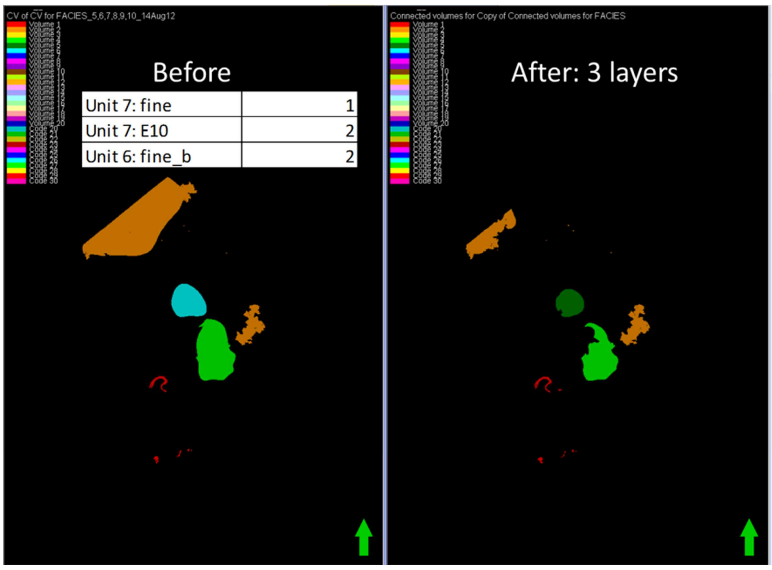


Figure 3-18: Step 2 Case 1 – Zone to zone comparison

Case 4 (Figure 3-19 & 3-20): 'Unit 6: E9', 'Unit 6: fine_a', and 'Unit 6: E8'. Total number of layers from contributing zones is 8 and there are 4 layers in the merged zone. Less significant change occurs in this case as there is only part of the second largest volume is lost. This could result from either a portion of the reservoir units of Orange being averaged with baffle or smaller volumes in the middle being filtered out and creates a hole-shaped geometry in the volume provides comparison between the zones before and after coarsening.

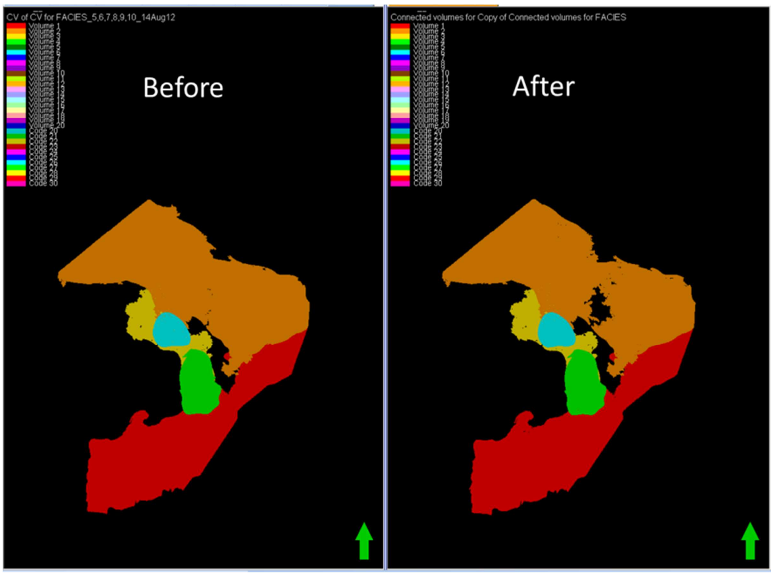


Figure 3-19: Step 2 Case 4

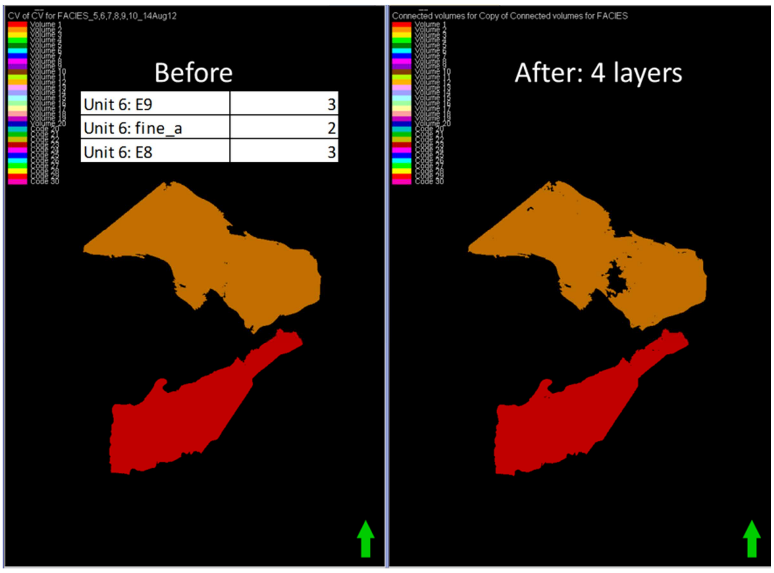


Figure 3-20: Step 2 Case 4 – Zone to zone comparison

Case 19 (Figure 4-21 & 4-22): ‘Unit 4: fine_a’, ‘Unit 4: E1’ and ‘Unit 3’. Total number of layers from contributing zones is 9 and layering in the merged zone is 5. It has been realized that merging the bottom zones will most certainly bring change to the fine model. The third largest volume yellow (before) is significantly reduced into green (after), part of the largest volume red (before) has become light blue (after). These changes can be easily tracked when comparing the 3 zones before merging and the one after in which there is a separation of yellow (before) into green and pink (after), also red into 2 smaller portions of it.

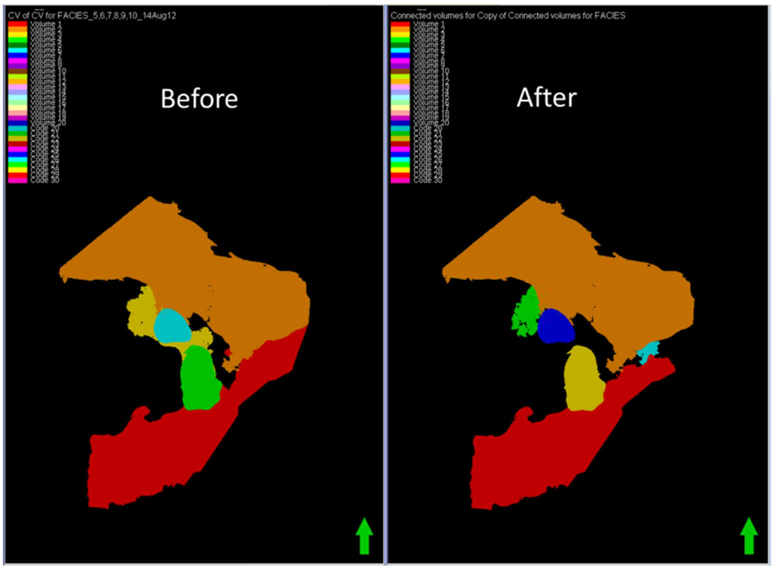


Figure 3-21: Step 2 Case 4

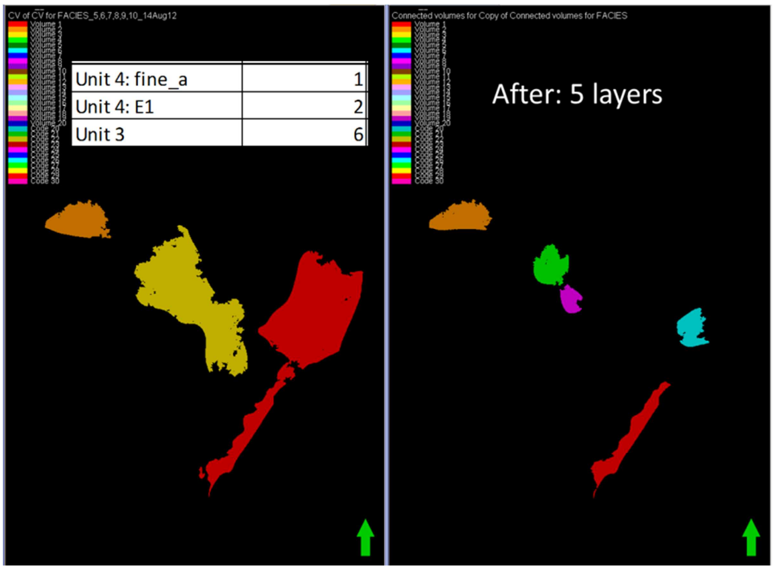


Figure 3-22: Step 2 Case 4 – Zone to zone comparison

3.3.3. Combined Effects

When both vertical and lateral coarsening methods are adopted on the model, significant modification of connected volumes is observed in almost all cases; which is expected during pre-simulation when reservoir engineers scale up a subsurface model without adequate understanding of the geology. Types of modification include disconnection of larger volumes, redistribution of the top 30 or 5 volumes, and all the volumes being connected as one large reservoir body. These changes are again the direct outcome of traditional scale-up workflow when little information is collected from subsurface environments. Not knowing the stratigraphy and setup of geology features will most likely misguide an engineer in building his simulation grid cells only to find out later he has missed out quite a lot. The process of coarsening facies distribution has caused reservoir units to be averaged with baffle and where baffle cells dominate and/or are of larger thickness, thus making reservoir facies disappear where it should be present. The workflow to generate top 5 connected volumes also contributes to disintegrating them into smaller parts since the 30 largest volumes after first attempt are not the same as they were in the original model.

3.3.3.1. 10x10(m) Grid Resolution

Step 1: All cases display loss and/or redistribution of the top 5 connected volumes. One can correlate each case with the model stratigraphy to learn more about how merging which group of adjacent zones has resulted in breaking down certain connected volumes. Some modification is similar to that observed in earlier vertical scenarios particularly in the case of combining zones at the bottom. What can be seen through this process is the impact of two steps in the workflow: averaging reservoir with baffle facies units and filtering down to top 30 connected volumes before grouping them to the top 5.

In Case 2 (Figure 3-23, 3-24 & 3-25) the largest volume breaks down and the fifth largest volume disappears because of filter effects. Zone-to-zone comparison reveals a significant portion of the second largest volume (orange) is lost while the fifth largest volume got filtered out. The number of top 30 volumes is arbitrary and has been selected to clean up small and scattered connected volumes which reflect insignificant reservoir units. This explains why it does not seem to take into account the part where Red Volume breaks down during merging of 'Unit 7: E10' and 'Unit 6: fine_b' and yet the largest volume still splits into two. Figure 3-24 shows first-step connected volumes before and after the filter is applied with the area where there are cells that connect parts of Red Volume clearly marked. It is observed that these cells are taken out during the process thus resulting in Red Volume splitting up into two. Notice that the color legend remains the same but color assignment of each volume has changed due to redistribution of the connected volumes. Meanwhile the fourth largest volume shrinks into a smaller one due to being averaged with baffle from 'Unit 6: fine_b'.

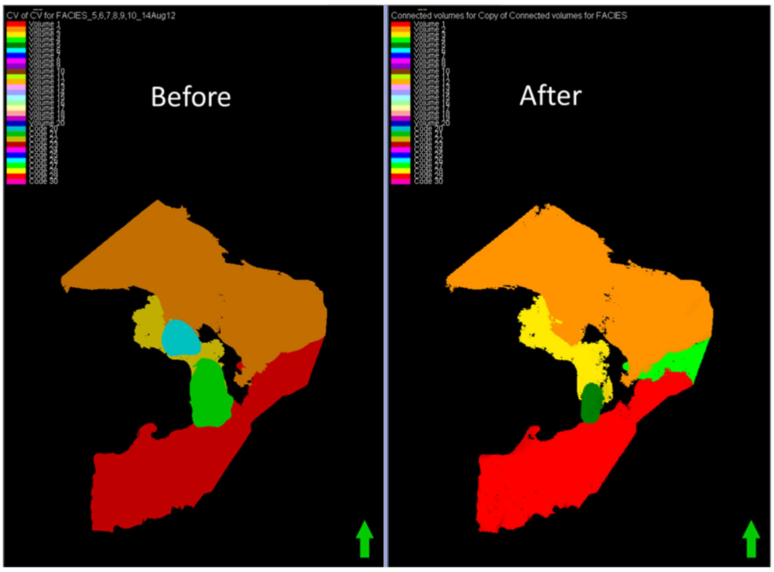


Figure 3-23: 10x10(m) Step 1 Case 2

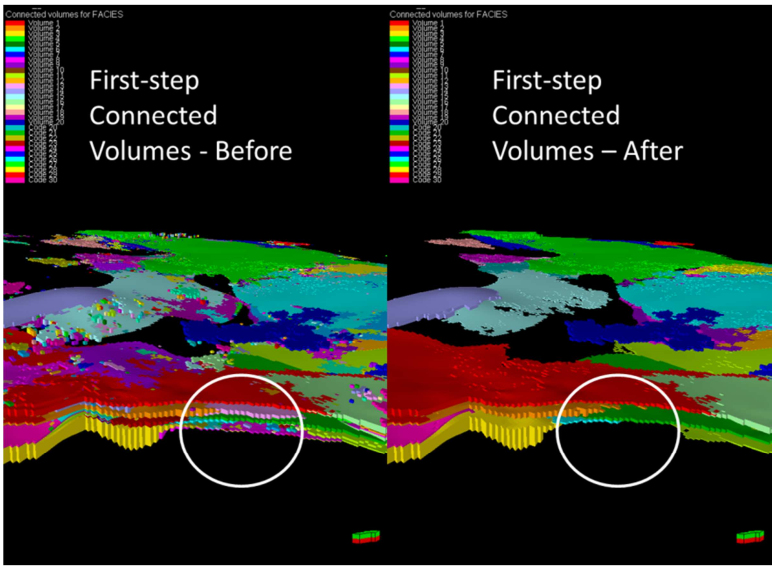


Figure 3-24: 10x10(m) Step 1 Case 2 – Filter effects

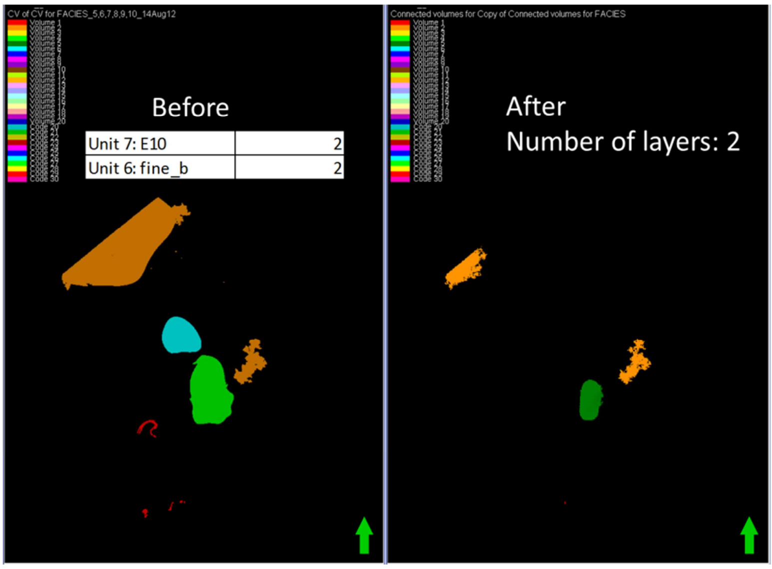


Figure 3-25: 10x10(m) Step 1 Case 2 – Zone to zone comparison

Case 4 (Figure 3-26 & 3-27) displays mainly the filter effects on connected volumes with the largest volume (red) breaks into smaller ones and fifth largest volume got taken out. Similar to Case 2, there are cells that connect portions of the largest connected volume and when they are no longer there Petrel would take it as there are separate volumes in the same area. Though relatively less significant than filter effects, the impact of merging 'Unit 6: E9' and ‘Unit 6: fine_a’ can also be seen in this case with the second largest volume (orange). Figure 3-27 indicates the area where reservoir facies have been averaged with baffle, therefore resulting in a void in the middle of the second largest volume. Although the volume is supposed to shrink, merging effects also connect the second and third largest volumes into one (filter effects will most likely split up rather than combine volumes).

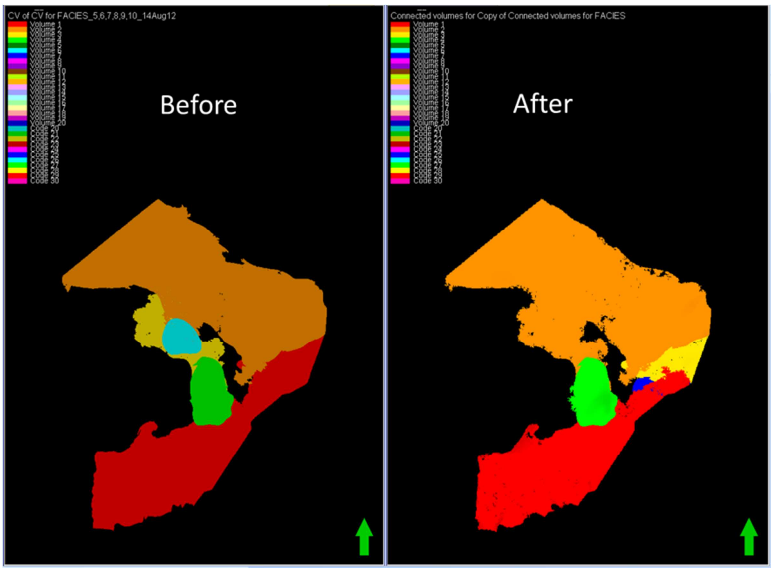


Figure 3-26: 10x10(m) Step 1 Case 4

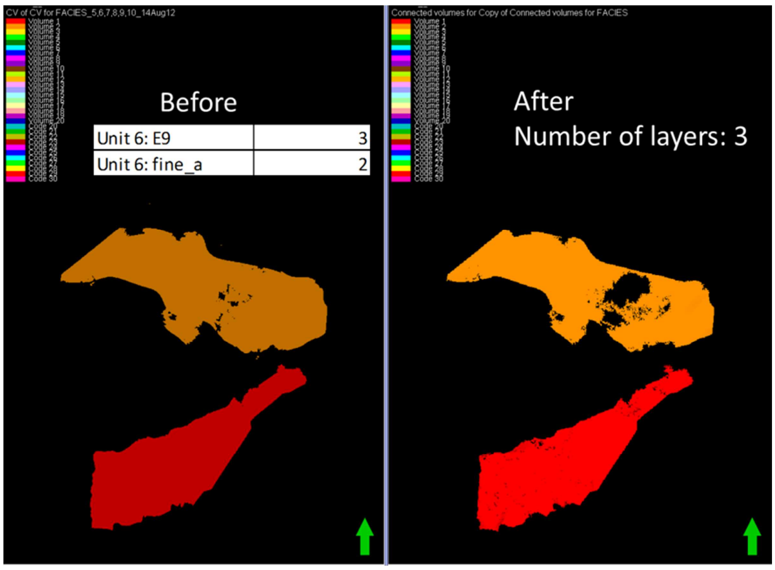


Figure 3-27: 10x10(m) Step 1 Case 4 – Zone to zone comparison

Case 20 (Figure 3-28 & 3-29) is the most severely affected by coarsening as shown in Figure 3-28. The largest and third largest volumes are broken partly because of how much resolution is compromised when ‘Unit 4: E1’ and ‘Unit 3’ are merged and also due to filter effects. The total number of layers from contributing zones is 8 and number of layers in the new zone is 4. This has caused the third largest volume to split up into 2 after facies is scaled up. Filter effects play a role in separating the largest volume (red) and creating a hole-shaped geometry within the smaller part taken out from Red Volume (Figure 3-29).

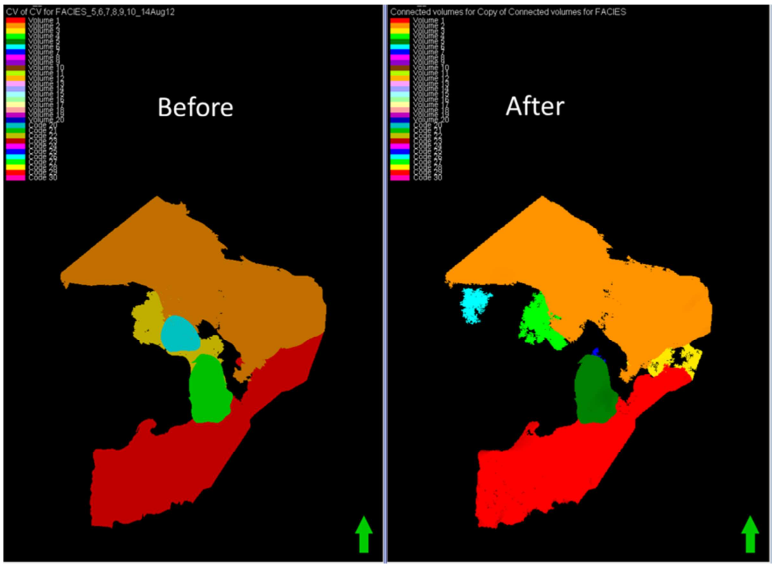


Figure 3-28: 10x10(m) Step 1 Case 20

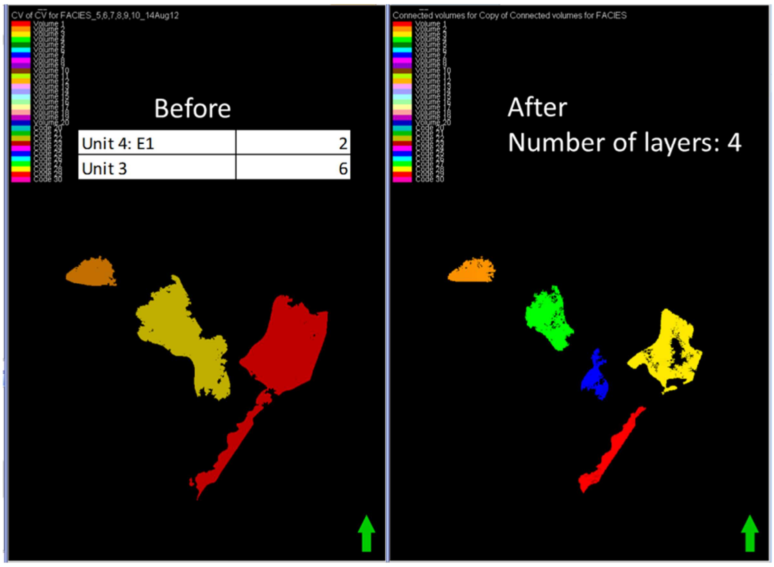


Figure 3-29: 10x10(m) Step 1 Case 20 – Zone to zone comparison

Step 2: This step in general displays more drastic changes than those of Step 1 because there are more zones involved in the process

Case 1 (Figure 3-30 & 3-31) reveals a new interesting shape of modification of the fourth largest volume (green) which results from averaging reservoir and baffle facies (Figure 3-30). The fifth largest volume (blue) slightly shrinks in the same manner. This case is a combination of 'Unit 7: fine', 'Unit 7: E10' and 'Unit 6: fine_b'; the total number of layers is reduced from 5 to 3. Since there are two baffle zones versus one reservoir zone, part of the fourth largest volume ends up being dominated by baffle during sampling of facies property to the scaled up grid as compared to Step 1 where this does not occur (Figure 3-31).

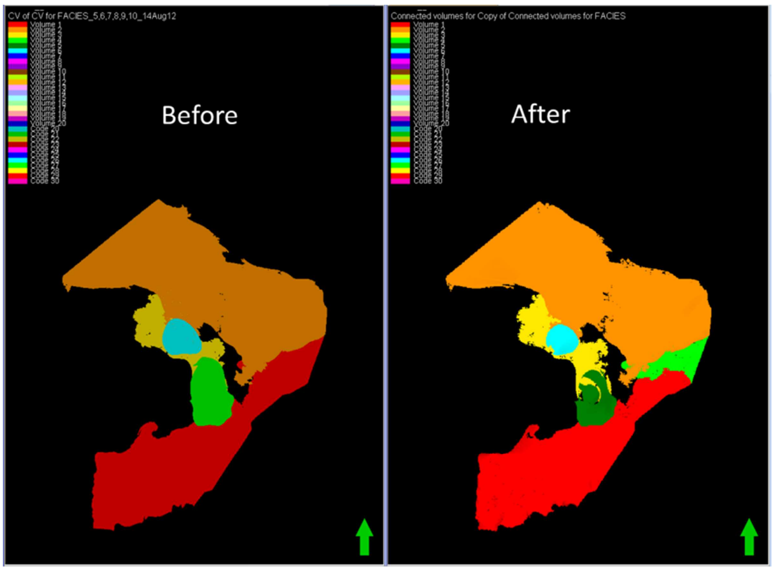


Figure 3-30: 10x10(m) Step 2 Case 1

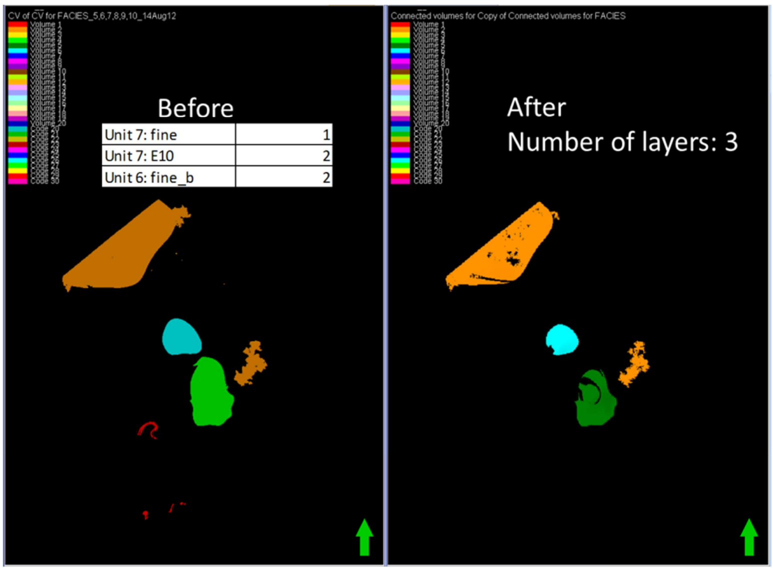


Figure 3-31: 10x10(m) Step 2 Case 1 – Zone to zone comparison

Case 3 (Figure 3-32 & 3-33) is a great example of disintegrating top 5 connected volumes into smaller ones by removing cells that connect larger volumes. Figure 3-32 shows the largest volume (red) breaks into 3 parts in this mechanism since these connecting cells have been filtered out. Again two baffle zones merge with a reservoir zone: 'Unit 6: fine_b', 'Unit 6: E9' and 'Unit 6: fine_a'. The second largest volume (orange) displays significant loss of connected volume underneath layers on the surface. Figure 3-33 reveals what is really happening with the zones after they are merged. Note that there are more than 5 volumes after scaling up therefore the color order is redefined from largest to smallest.

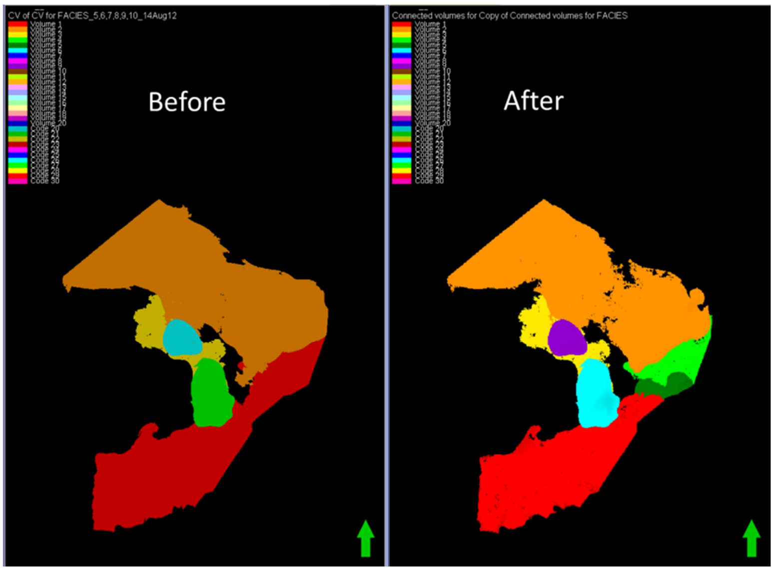


Figure 3-32: 10x10(m) Step 2 Case 3

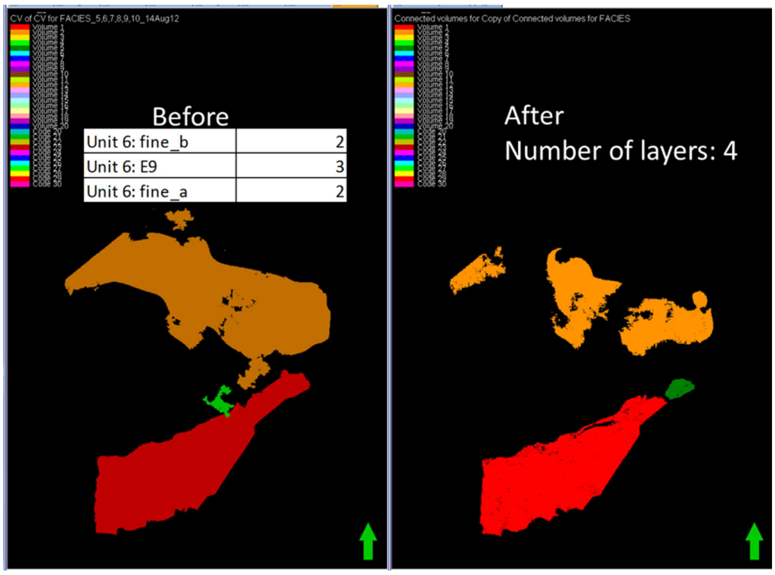


Figure 3-33: 10x10(m) Step 2 Case 3 – Zone to zone comparison

Case 19 (Figure 3-34 & 3-35) is the most affected in Step 2 in a similar pattern with previous cases when zones at the bottom are combined. This case merges ‘Unit 4: fine_a’, ‘Unit 4: E1’ and ‘Unit 3’ with total number of layers reduced from 9 to 5. Figure 3-34 displays change in color order which is a direct result of redistribution of top 5 volumes in the original model. Looking more closely into the zones before and after scaled up in Figure 3-35, the largest and third largest volumes (red & yellow) apparently lost a remarkable portion through a combination of both averaging reservoir and baffle facies and filtering out cells that connect larger parts of a volume. There is even a little tiny part of Red Volume got separated in the zone to zone comparison which shows how hard it is to define a good number of volumes to filter down to from the scaled up facies property.

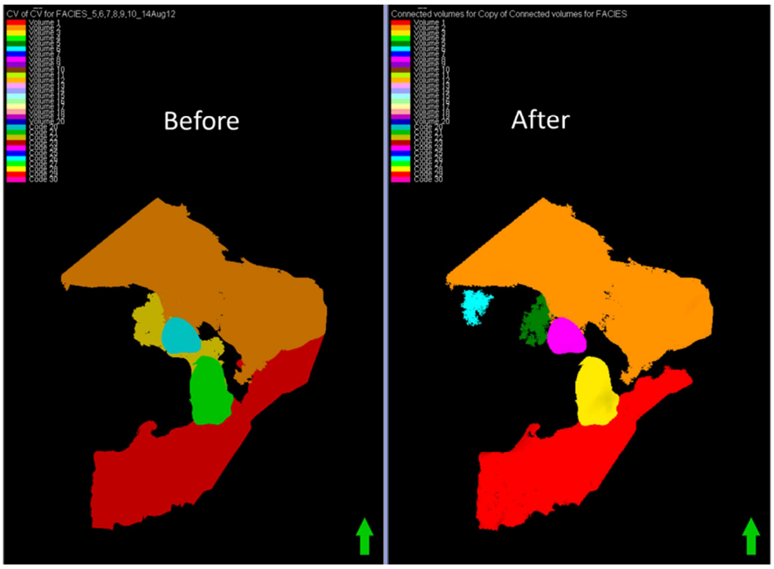


Figure 3-34: 10x10(m) Step 2 Case 19

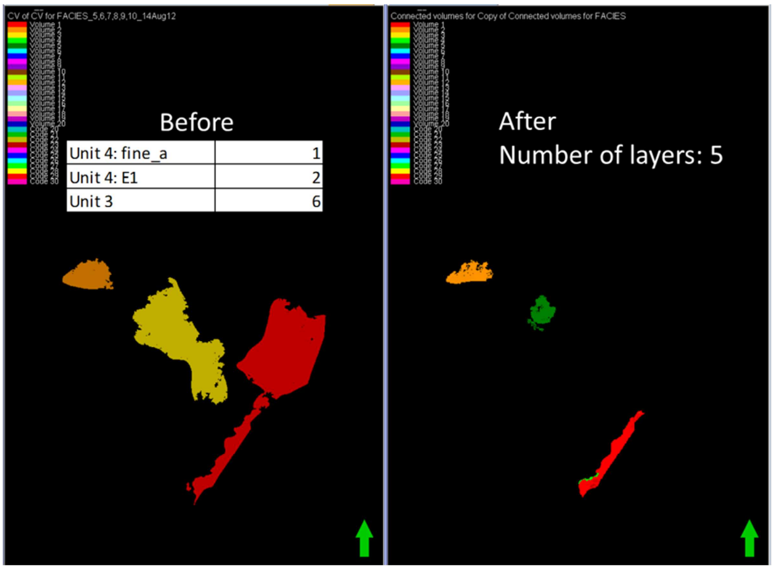


Figure 3-35: 10x10(m) Step 2 Case 19 – Zone to zone comparison

3.3.3.2. 15x15(m) Grid Resolution

Step 1: It is interesting to observe that except for a few cases such as 2 and 20, the majority show insignificant change in their volumes.

Case 2 (Figure 3-36, 3-37 & 3-38) sees the fourth largest volume (green) shrinks and fifth largest volume (blue) disappears. From the scaled up facies, both volumes have been merged with baffle and each gives up a part or all of its volume (Figure 3-36). Figure 3-37 proves that the fourth largest volume shrinks because its reservoir facies is dominated by baffle after facies property is sampled into the scaled up grid. Basically the fifth largest volume disappears because of filters and the fourth largest volume reduces its size due to being averaged with baffle facies (Figure 3-38).

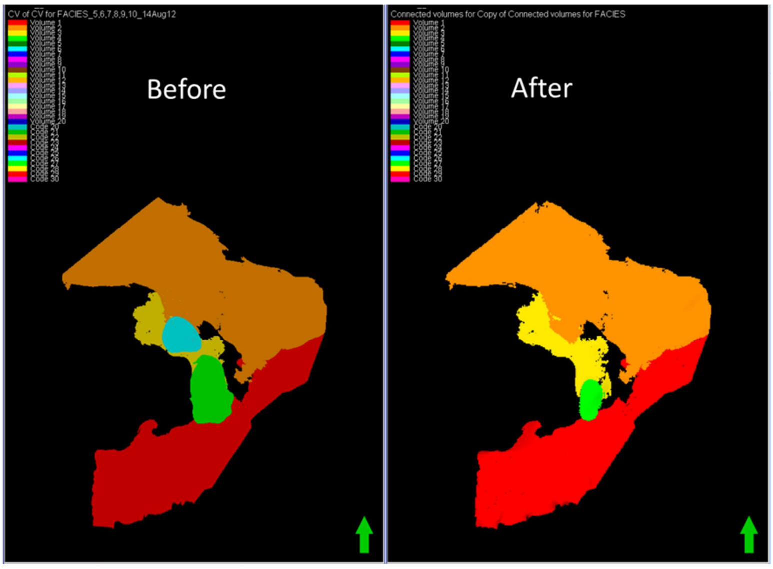


Figure 3-36: 15x15(m) Step 1 Case 2

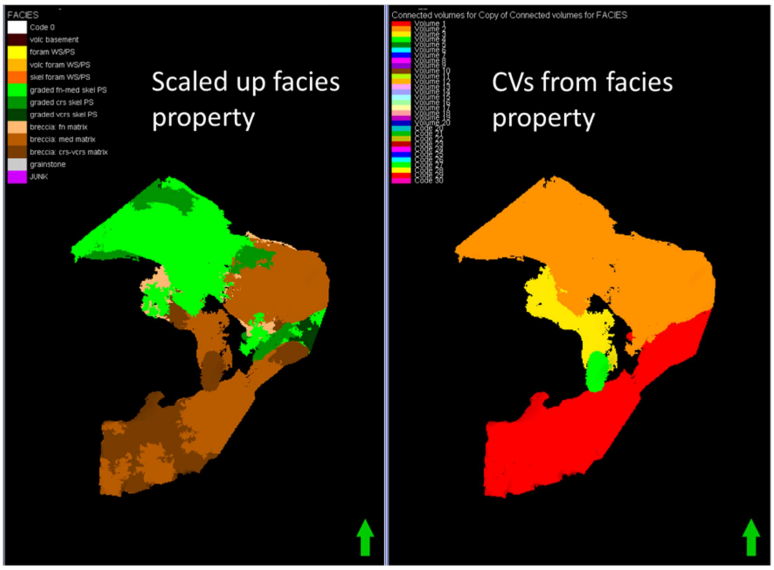


Figure 3-37: 15x15(m) Step 1 Case 2 – Facies and CVs after Scale-up

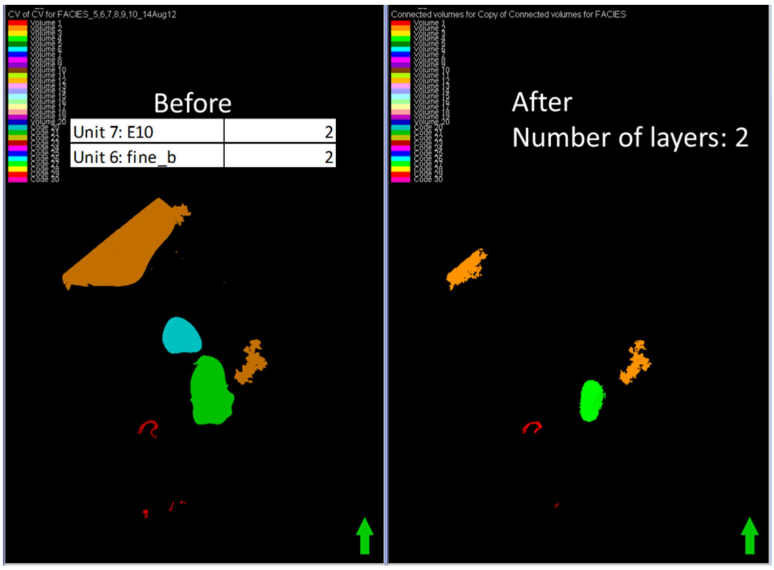


Figure 3-38: 15x15(m) Step 1 Case 2 – Zone to zone comparison

Case 20 (Figure 3-39 & 3-40) at the bottom reveals vertical coarsening effects are predominant as compared to lateral coarsening since this case is very similar to its counterparts regardless of lateral grid resolution (Figure 3-39). Figure 3-40 shows the largest and third largest volumes break down and/or shrink mainly due to smaller cells being filtered during scaling up. Consequently color assignment is redefined based on the new volume order from largest to smallest. This case merges 'Unit 4: E1' and 'Unit 3' with total number of layers being reduced from 8 to 4.

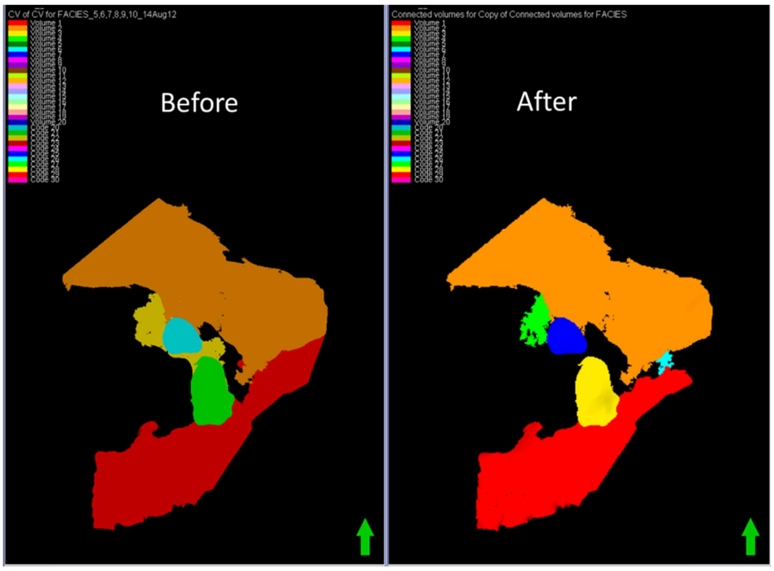


Figure 3-39: 15x15(m) Step 1 Case 20

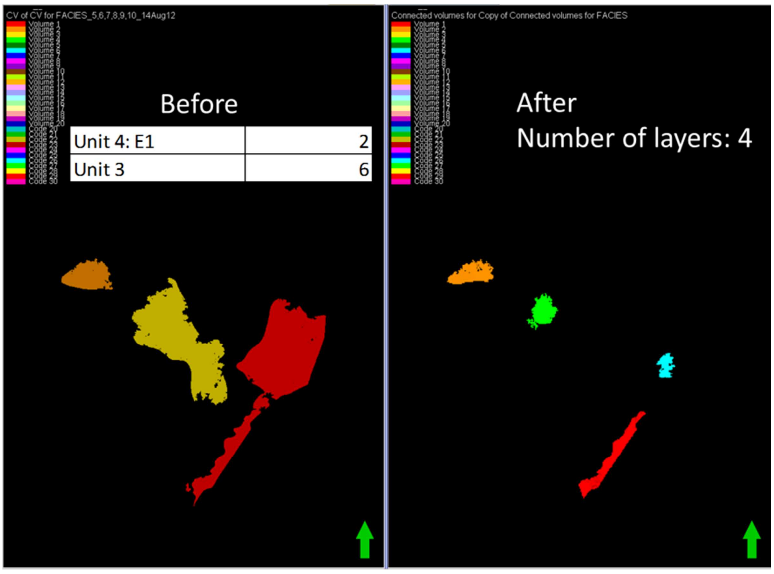


Figure 3-40: 15x15(m) Step 1 Case 20 – Zone to zone comparison

15x15(m) Step 2: Most cases show their volumes break down in a similar pattern except for these following

Case 1 (Figure 3-41 & 3-42) sees the effects of merging 2 baffle zones with one reservoir zone as the fourth and fifth largest volumes shrink. In Figure 3-41 there is no sign of filter effects since each of these volumes is made up of a reservoir facies by itself and not a group of reservoir facies. The setup of this case includes 'Unit 7: fine', 'Unit 7: E10' and 'Unit 6: fine_b'. Total number of layers from contributing zones is five and is reduced to three in the merged zone (Figure 3-42). From this it can be learned that 'Unit 7: E10' contains most of the fourth and fifth largest volumes and therefore merging it will most like affect these volumes.

Figure 3-41: 15x15(m) Step 2 Case 1

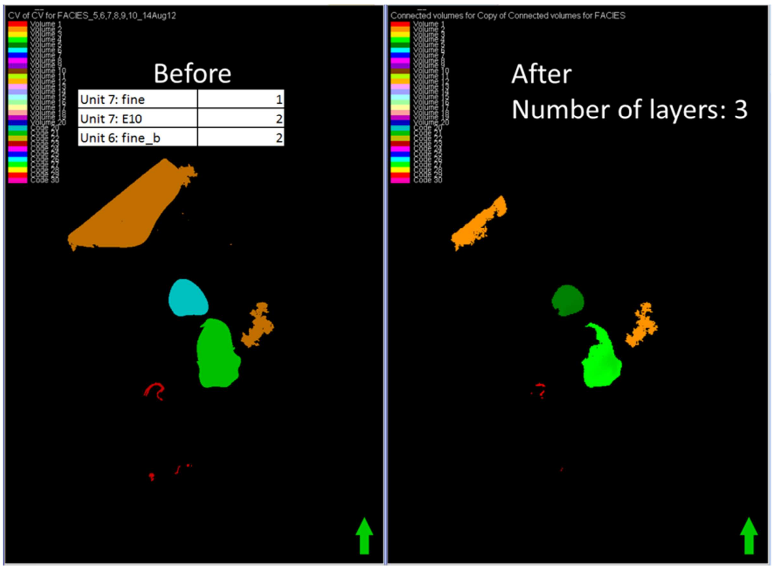


Figure 3-42: 15x15(m) Step 2 Case 1 – Zone to zone comparison

Case 4 (Figure 3-43 & 3-44) is mainly a representation of filter effects where the fifth largest volume has been taken out and a portion of the second largest is gone (Figure 3-43). The merging effects are not noticeable in this case since 2 reservoir zones ‘Unit 6: E9’ and ‘Unit 6: E8’ are combined with one baffle zone ‘Unit 6: fine_a’. Total number of layers from contributing zones is 8 and has been coarsened to 4 to increase cell thickness (Figure 3-44). This is done through Petrel standard “Scale up structure” process in which the total volume of 3 zones (after the horizons in between are removed) is kept and re-layered proportionally into 4 (Table 3-3). Again it is hard to define an optimal number to filter out cells that are insignificant to the model until after all the conceptual volumes are generated.

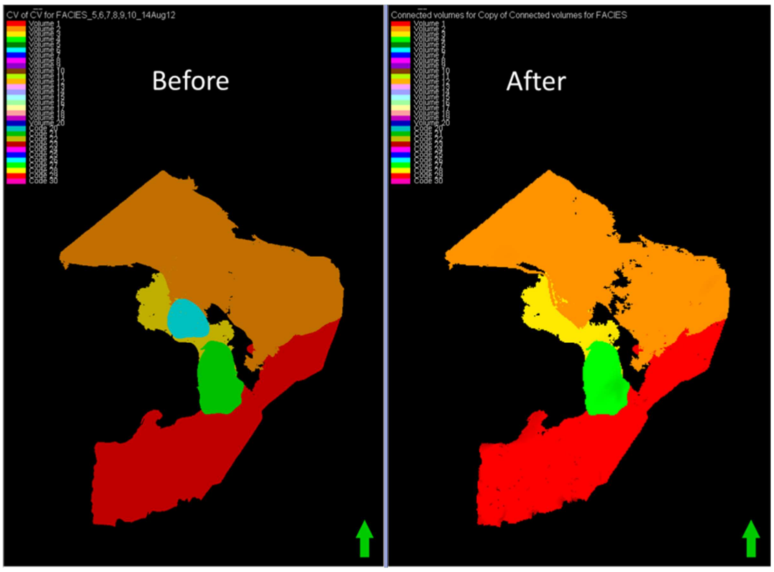


Figure 3-43: 15x15(m) Step 2 Case 4

	Name	Color	Top horizon	Base horizon	Zone division			Reference surface	Restore eroded	Restore base
	JUNK (0)		TOP	JUNK	Proportional	Number of layers:	1		Yes	Yes
	Unit 7: fine		JUNK	E10_T	Proportional	Number of layers:	1		Yes	Yes
	Unit 7: E10		E10_T	E10_B	Proportional	Number of layers:	2		Yes	Yes
	Unit 6: fine_b		E10_B	PV_E9	Proportional	Number of layers:	2		Yes	Yes
	Unit 6: E9		PV_E9	PV_E8	Proportional	Number of layers:	4		Yes	Yes
	Unit 5: fine_c		PV_E8	PV_E7	Proportional	Number of layers:	2		Yes	Yes
	Unit 5: E7		PV_E7	PV_E7	Proportional	Number of layers:	1		Yes	Yes
	Unit 5: fine_b		PV_E7	PV_E6	Proportional	Number of layers:	4		Yes	Yes
	Unit 5: E6		PV_E6	PV_E6	Proportional	Number of layers:	2		Yes	Yes
	Unit 5: fine_a		PV_E6	PV_E5	Proportional	Number of layers:	2		Yes	Yes
	Unit 5: E5		PV_E5	PV_E5	Proportional	Number of layers:	2		Yes	Yes
	Unit 4: fine_d		PV_E5	PV_E4	Proportional	Number of layers:	4		Yes	Yes
	Unit 4: E4		PV_E4	PV_E4	Proportional	Number of layers:	2		Yes	Yes
	Unit 4: fine_c		PV_E4	PV_E3	Proportional	Number of layers:	1		Yes	Yes
	Unit 4: E3		PV_E3	PV_E3	Proportional	Number of layers:	1		Yes	Yes
	Unit 4: fine_b		PV_E3	PV_E2	Proportional	Number of layers:	1		Yes	Yes
	Unit 4: E2		PV_E2	PV_E2	Proportional	Number of layers:	2		Yes	Yes
	Unit 4: fine_a		PV_E2	PV_E1	Proportional	Number of layers:	1		Yes	Yes
	Unit 4: E1		PV_E1	PV_E1	Proportional	Number of layers:	2		Yes	Yes
	Unit 3		PV_E1	UNIT_	Proportional	Number of layers:	6		Yes	Yes
	Unit 1		UNIT_	UNIT_	Proportional	Number of layers:	8		Yes	Yes

Table 3-3: “Scale up structure” Process – 15x15(m) Step 2 Case 4

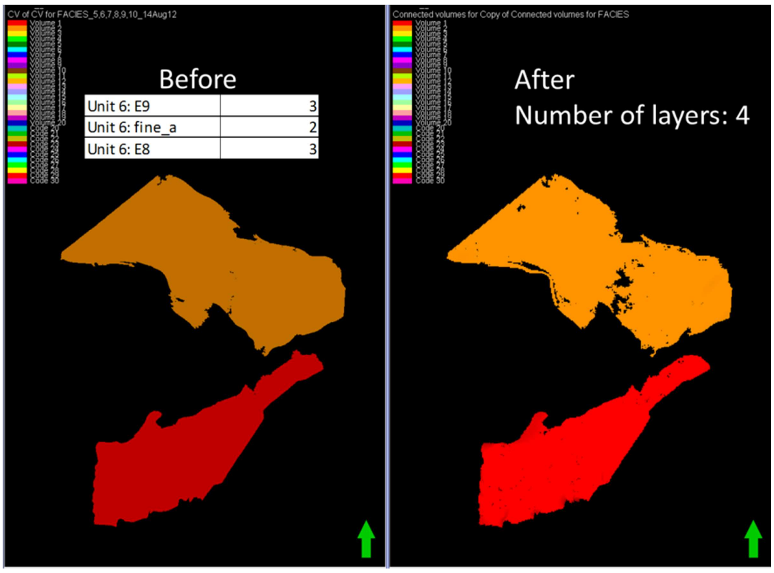


Figure 3-44: 15x15(m) Step 2 Case 4 – Zone to zone comparison

Case 19 (Figure 3-45 & 3-46) combines all 3 layers at the bottom and displays both merging and filtering effects on the model (Figure 3-45). Figure 3-46 shows ‘Unit 4: fine_a’, ‘Unit 4: E1’ and ‘Unit 3’ are merged in case 19 with total number of layers going from 9 to 5. This tells how much detail has been lost in the vertical direction when these zones are scaled up which is why case 19 is the most affected in Step 2. The largest and third largest volumes shrink and split up into smaller portions. This is a very typical pattern for most cases that involve merging adjacent zones at the bottom.

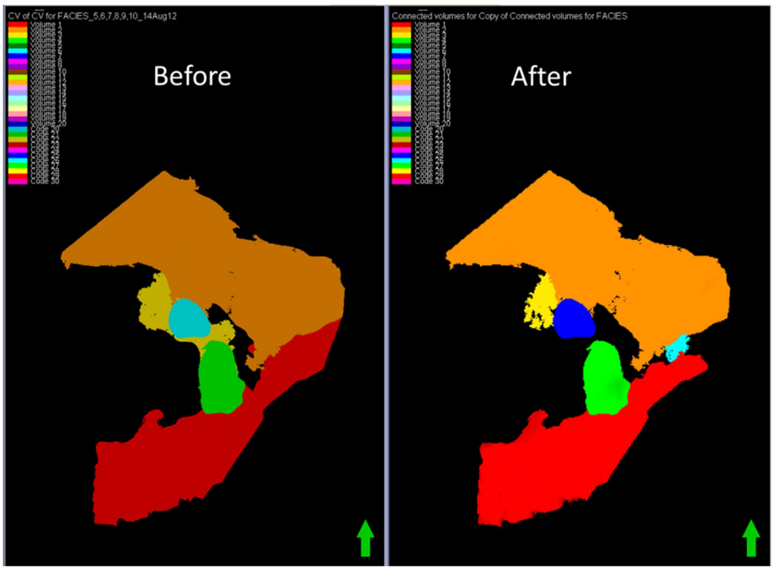


Figure 3-45: 15x15(m) Step 2 Case 19

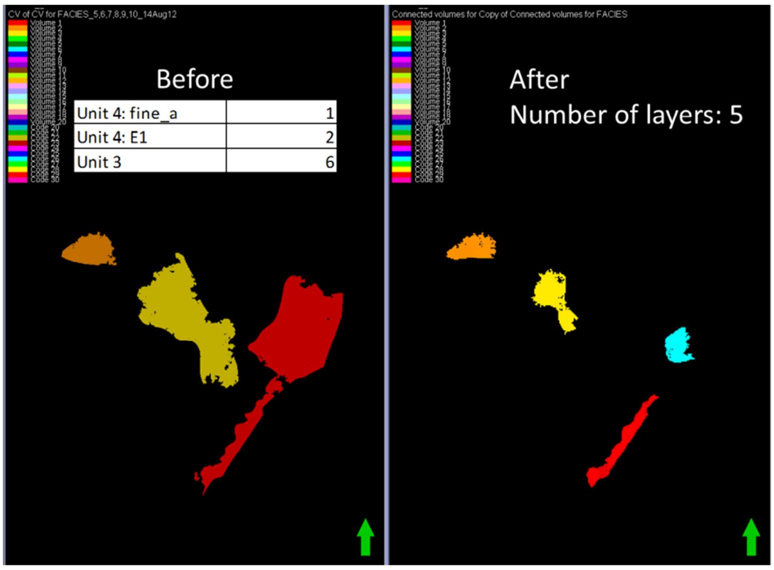


Figure 3-46: 15x15(m) Step 2 Case 19 – Zone to zone comparison

3.3.3.3. 30x30(m) Grid Resolution

30x30(m) Step 1: Case 20 shows the most striking change of all cases

Case 2 (Figure 3-47 & 3-48) shows a very similar pattern to 10x10 and 15x15(m) grid resolutions. Lateral coarsening seems to have a relatively insignificant impact on the model as compared to vertical coarsening (Figure 3-47). In Figure 3-48 as baffle zone 'Unit 6:

fine_b’ is combined with reservoir zone ‘Unit 7: E10’ merging effects take place on the fourth largest volume and make it shrink. The fifth largest volume on the other hand is filtered out during the process of making top 5 connected volumes. ‘Unit 7: E10’ contains most of the fourth and fifth largest volumes therefore when it is merged these volumes are the one being affected.

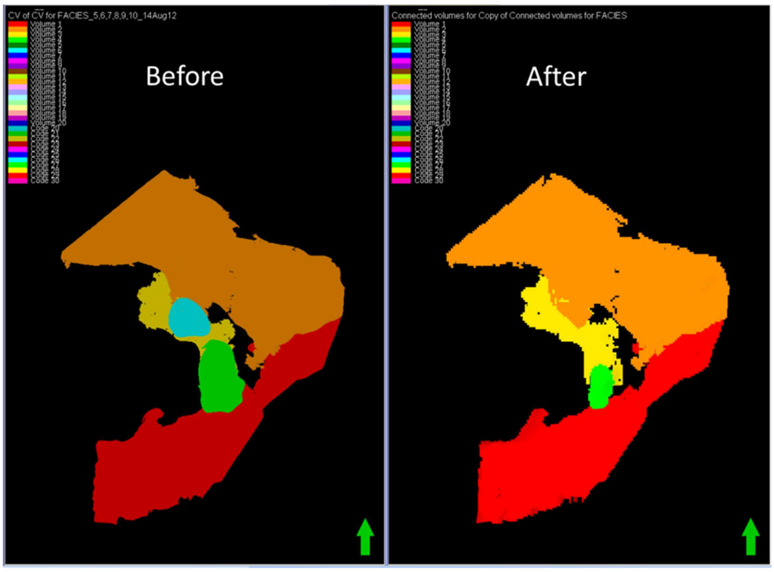


Figure 3-47: 30x30(m) Step 1 Case 2

Figure 3-48: 30x30(m) Step 1 Case 2 – Zone to zone comparison

Case 20 (Figure 3-49 & 3-50) mostly observes filter effects on the bottom zones which make the largest and third largest volumes split up into two parts (Figure 3-49). Figure 3-50 displays what is really going on with the zones being merged. Lateral resolution does not seem to affect the model as much as with its counterparts in 10x10 and 15x15(m).

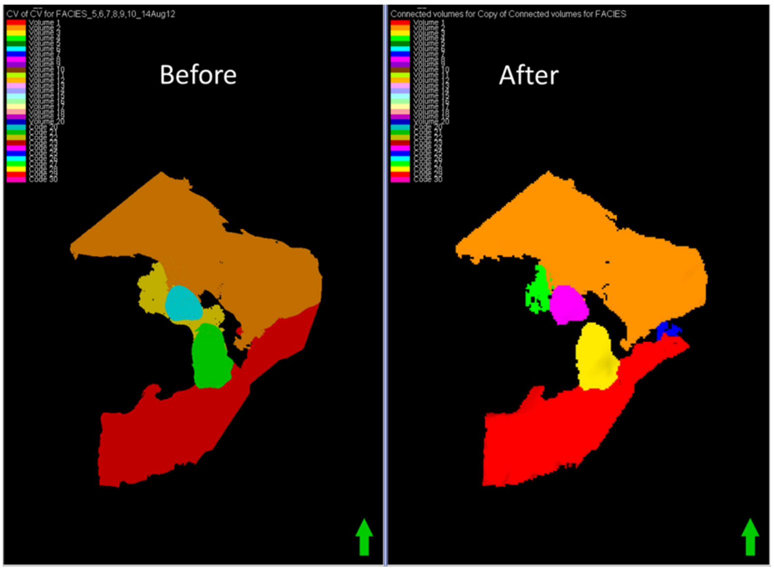


Figure 3-49: 30x30(m) Step 1 Case 20

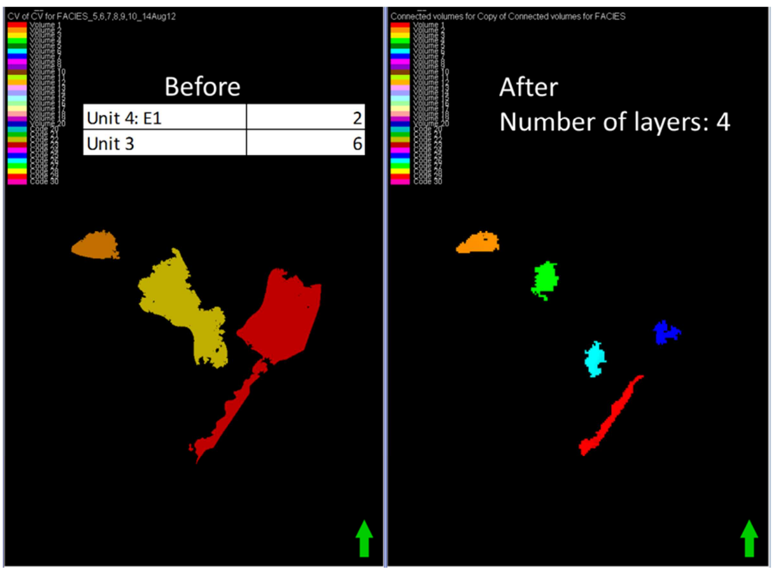


Figure 3-50: 30x30(m) Step 1 Case 2 – Zone to zone comparison

30x30(m) Step 2: More drastic changes are observed in Step 2 than Step 1

Case 1 of Step 2 (Figure 3-51 & 3-52) shows more significant merging effects as 2 baffle zones ‘Unit 7: fine’ and ‘Unit 6: fine_b’ are merged with reservoir zone ‘Unit 7: E10’ (Figure 3-51). Figure 3-52 reveals that not only the fourth and fifth largest volumes shrink but also a significant portion of the second largest volume is lost as well. Thus far a common manner has been identified in which the model will most likely behave when certain zones are merged. This could really help retain reservoir heterogeneity and guide engineers through working with building the simulation grid cells.

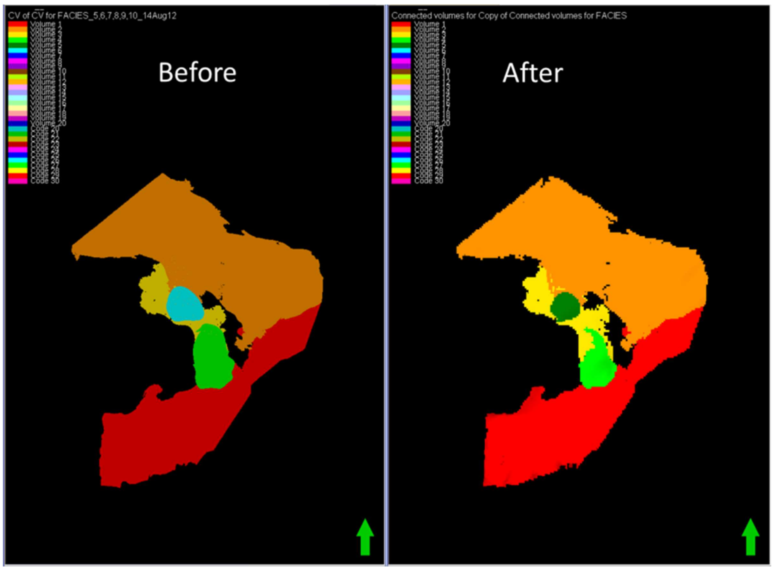


Figure 3-51: 30x30(m) Step 2 Case 1

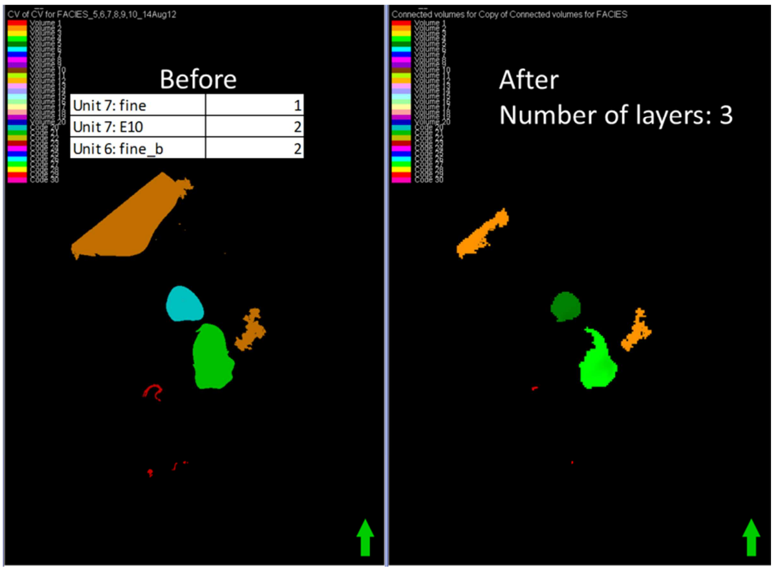


Figure 3-52: 30x30(m) Step 2 Case 1 – Zone to zone comparison

Case 19 (Figure 3-53 & 3-54) shows a lot of similarity to all previous cases which merge zones at the bottom (Figure 3-53). In Figure 3-54 the legend remains the same but color assignments have changed because of redistribution of the connected volumes in size. The largest and third largest volumes see both merging and filtering effects that contribute to making them shrink and/or split up. The rest of the case resembles what has already been discussed earlier in similar bottom zone cases.

Figure 3-53: 30x30(m) Step 2 Case 19

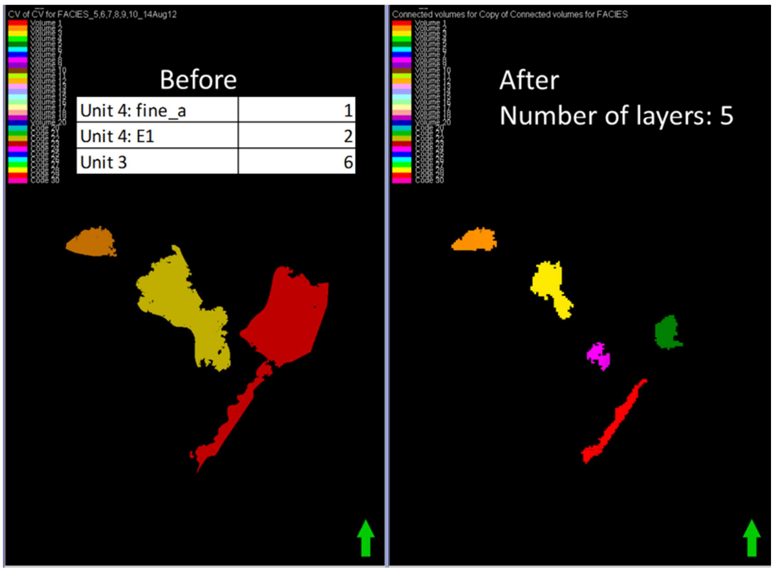


Figure 3-54: 30x30(m) Step 2 Case 19 – Zone to zone comparison

3.4. Summary

The Agua Amarga model provides some findings through coarsening fine-scale observation from the field in an attempt to explore how this would work in building reservoir simulation cells. Vertical coarsening shows more impact than lateral coarsening for this particular model. The most significant impact also came from having adjacent zones merged and cell thickness increased. This would encourage reservoir engineers to look more closely into formation stratigraphy and find out what should be modified and what should be left alone. Also within vertical coarsening workflow, merging effects are more pronounced in Step 2 and show more drastic changes than Step 1. This is expected when there are 2 or more baffle zones being merged with a reservoir zone. Due to the time and scope constraints of this modeling work, much can still be done to gain more insights into a broader variety of upscaling techniques. A potential direction would be to scale up facies using other algorithms and discrete coarsening methods offered in Petrel. As facies is a discrete property there are a limited number of methods which can be used (Table 3-4) and in this study only 'Most of' averaging method is implemented. Other sampling methods are also available through 'Scale up properties' process (Figure 3-55) since only 'Source cell centers' method is applied at this point. In all, the Agua Amarga model provides an example that shows facies scale-up may not be the best practice to implement in a geological model.

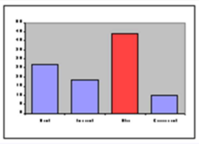
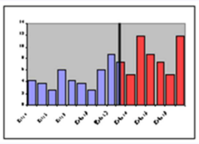
Most of		Also known as "mode", this method assigns the most strongly represented source value to the target cell. For example, when using volume-weighted averaging to upscale a facies property, a particular coarse cell overlapping fine cells containing a total of 1000 m^3 of sand, 2500 m^3 of silt, and 3000 m^3 of shale, will be set to shale.
Median		Takes the median of source cell property values (ordered by their numerical codes). The median is the value for which half of the source weight (e.g. volume weight) is lower and half is higher, or the closest possible discrete value.
Minimum		Selects the discrete value with the lowest numerical code.
Maximum		Selects the discrete value with the highest numerical code.
Arithmetic		Performs arithmetic averaging of the source values using their numerical codes, and selects the value with the nearest numerical code to the result.

Table 3-4: Discrete Property Averaging Methods in Petrel

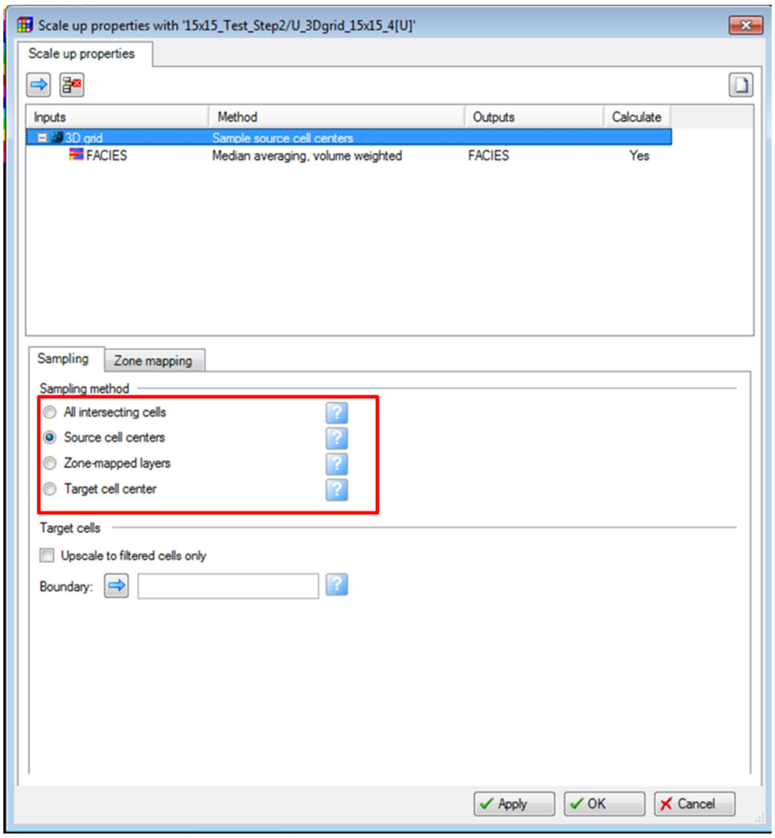


Figure 3-55: Sampling Methods in 'Scale up properties' process

This project has answered a given question: will the major connected volumes be affected during coarsening of the facies property model and to what extent? Results from scaled up models clearly demonstrate the fact that without geology understanding of the study area and measured stratigraphy, building simulation grid cells would be misguided. As to how far re-gridding would go into modifying the original facies is also shown through what can be seen from the model. Disintegration and redistribution of top 5 connected volumes are commonly observed and would most likely have a significant impact on the way how this reservoir should be explored and recovered if it were a real subsurface unit.

Chapter 4: Conclusions & Recommendations

4.1. Conclusions

4.1.1. La Molata Simulation Project

Sensitivity study of input parameters and development scenarios provides a better understanding of the primary controls on flow behavior in TCC and DS3. The study focuses on three main diagenetic models including Base Case, Rank Transformed and Variable Dolomite.

In TCC, Permeability populated with Scatter tends to show a slight decrease, sometimes negligible, in recovery compared to the regular No Scatter one derived from Standard Property Calculator (SPC). Mobility ratios between the displacing phase (water) and displaced phase (oil) are influential factors in recovering hydrocarbons. Imbibition process is implemented to evaluate the effect between single and multiple sets of relative permeability and capillary pressure curves. The results vary among diagenetic models due to their permeability variation. Base Case and Variable Dolomite have more cells with permeability above 100mD; therefore their multiple curves resemble the case with high-end Kr and Pc curves. Rank Transformed, on the other hand, has the majority of its cells between 10 and 100mD and multiple curves perform closer to medium Kr and Pc curves.

Study of well locations confirms that a production well on the updip would produce more than one on the downdip because of gravity helping to stabilize the displacement front. The additional amount of oil is even increased with favorable mobility ratios. Study of completion intervals suggests that a full completion plan may not be required for the entire reservoir interval, for the difference between full and half completion is not pronounced. In practice, it may not compensate for the investment made to complete the whole section of the reservoir. Another scenario examines the common well patterns (5-spot, 9-spot) and learns that given the same volume of water injection, the 5-spot pattern would recover more than 9-spot setup. This makes 5-spot injection a more viable choice in terms of cost-effectiveness for this reservoir analog.

There are three sequence boundaries in TCC that extend laterally and contain microbialites associated to low permeability. Topmost boundary among the three is the most extensive and has an impact on flow behavior and recovery performance, though the effect does not seem remarkable due to the boundaries being so thin (0.5m). This has answered the questions given to TCC regarding to how these boundaries would affect the recovery process. Thin sequence boundaries are what need to be retained during rescaling of the grid to reflect its original geology. Simulation gridding has found the right sampling methods for porosity and permeability that reproduce the initial model performance after fine grids are either laterally or vertically coarsened. A workflow for this involves tuning between various sampling methods to find the best method. It is found that tuning porosity has a better impact on recovery before water breakthrough while tuning permeability clearly affects recovery after water breakthrough.

DS3 is a much larger and more complex model that takes a considerable amount of simulation time. The majority of simulations are performed using a streamline simulator to speed up runs and provide an estimate of recovery trend in the system. Simulation study shows that facies associated with low permeability would be where oil is left behind after water injection. Permeability with Scatter has very limited effect on the recovery of DS3. To remove the restriction of the existence of erosion surfaces in the model, the simulations can be conducted with creation of non-neighbor connections and allow flow communication between zones.

Coarsening the DS3 fine grid for simulation finds that upscaling the model laterally may not preserve reservoir geometry and heterogeneity. This is because the number of cells is reduced at least four times and a lot of pinch-out cells are removed from the original model, resulting in different pore volumes. On the other hand, the DS3 model can be scaled up vertically up to 2m thickness and can still be able to match initial model performance.

DS2 and DS1 units are briefly experimented with waterflood in this study. For DS2, the results show sideway injection yields better recovery on PV injected as compared to the case with water flood from down dip. DS1 injection study shows that oil is left behind in between production wells in facies associated with lower permeability.

4.1.2. Agua Amarga Scale-Up Study

The Agua Amarga project answers a question asked: would the top five connected volumes be turned into one large volume once facies is scaled up vertically or laterally? And how much change would there be? Throughout the study, merging and filter effects take place to reduce one or more of the top five volumes, make one or more of them disappear, break down some volume into smaller ones. However, the top five volumes do not combine into one.

4.2. Recommendations

1. TCC and DS3 can be further investigated with enhanced oil recovery to improve both microscopic and macroscopic displacement. DS2 and DS1 can be studied with various well locations and scale-up scenarios for simulation gridding.

2. ECLIPSE black oil simulator 2011.1 does not automatically report recovery efficiency; therefore one should specify the output using FOE in the SUMMARY section of a DATA file. Also there is known problem with saving the project in Petrel 2011.1, it would be better to carry on research with a newer version of Petrel.
3. For DS3, erosion surfaces can be removed by adding non-neighbor connections into the streamline model: (1) Set up a pore volume threshold and maximum pinch-out thickness, (2) Add the following keywords in the SCHEDULE section of DATA file to allow FRONTSIM simulator to define non-neighbor connections:

   OPTIONFS

   15* 1 /

   RPTSCHED

   FREQ=1 /

4. Further study can be done with other areas of the whole DS3 model instead of the up dip platform alone. Convergence and simulation time is a problem for running the entire model. One can keep simulation running in ECLIPSE black oil simulation by adding the following keyword to RUNSPEC section for when error and problem messages exceed the limit:

   MESSAGES

   8* 1000000 1000000 /

5. Based on Agua Amarga study, an improvement in the workflow is suggested by not applying a filter after connected volumes are first generated from facies property model. Instead, it should be done after all initial volumes are grouped and the major connected volumes are identified with its filter. This could change the number of top

5 volumes as when the original model is reconstructed, the largest and fourth largest volumes become one (Figure 4-1).

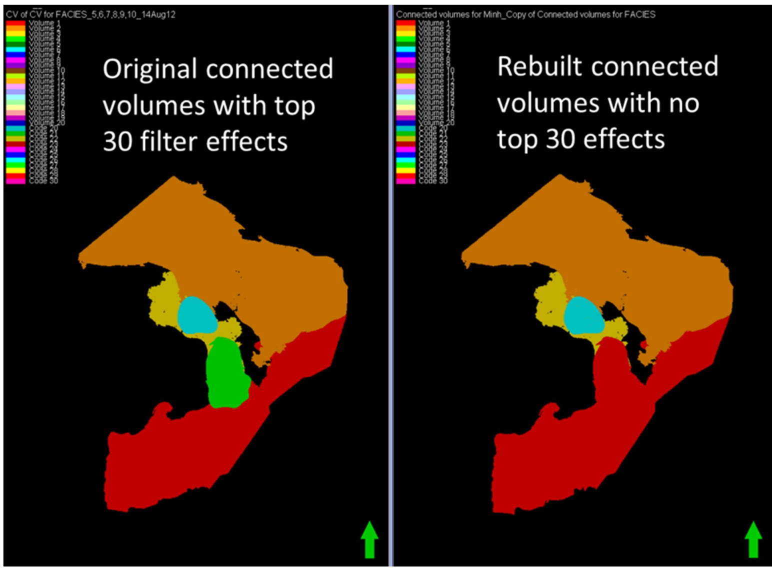


Figure 4-1: Original model vs Rebuilt model

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