A New Approach to History Matching of Water Driven Oil Reservoirs

A DISSERTATION
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بسم الله الرحمن الرحيم

قال تعالى

{وَيَسْأَلُونَكَ عَنِ الرُّوحِ قُلِ الرُّوحُ مِنْ أَمْرِ رَبِّي وَمَا أُوتِيتُم مِّنَ الْعِلْمِ إِلاَّ قَلِيلاً}

{وَقُل رَّبِّ زِدْنِي عِلْمًا}

{يَرْفَعِ اللَّهُ الَّذِينَ آمَنُوا مِنكُمْ وَالَّذِينَ أُوتُوا الْعِلْمَ دَرَجَاتٍ}

صدق الله العظيم

نحمد الله العلي القدير ونسأله أن يدلنا إلي ما يحب ويرضي

Affidavit

I declare in lieu of oath that I did this work by myself using only literature, cited in the text and listed in the end of this volume.

Dipl.-Ing. Fathe A.S Abrahem

Leoben, October 2009

Dedication

First of I all I would like to say thanks to my GOD, for everything, and I would like to dedicate this work firstly to my family, secondly to my beloved country and loved ones of each.

Acknowledgment

The author thanks em.O.Univ.Prof.Dipl.-Ing.Dr.Dr.h.c. Zoltan Heinemann to teach and guide him during his Master of Science and Doctorate study in Petroleum Engineering over the years 2004-2009. The research topic awarded by Prof. Heinemann was not only scientifically exciting but with high practical importance for the author's country the Great Arabian Jamahariya. The author thanks for continuous and intensive support by Prof. Heinemann and his colleagues, Dr. Georg Mittermeir and Dr. Andreas Harrer. The author is aware that to be the MS and PhD student of one of the winner of John Franklin Carrl Award confer him a particular state in the petroleum industry and science and he will try to be worthy to his sperendipity.

The author would like to thank so much NOC Libya and ZOC for granting permission for this study; furthermore thanks to AGOCO Libya for the permission using the data of the KOTLA field in this work, which is highly appreciated.

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Kurzfassung

Ein neuer Ansatz des History Matching für Öllagerstätten mit Wassertrieb

von Dipl.Ing.Fathe A.S.Abrahem

In dieser Dissertation wird eine neue Methode des History Matching präsentiert. Ziel der konventionellen Methode ist es ein Lagerstättenmodell zu erstellen, das die historischen Daten, wie Förderraten, Bohrlochdrücke, Wasseranteil und GOR über die gesamte Produktionszeit mit vorgegebenen Bohrlöchern simulieren kann. Bei der hier präsentierten Methode wird das Lagerstättenmodell als gegeben angenommen, die Bohrlöcher im Modell werden automatisch platziert, wobei diese Pseudo-Bohrlöcher nicht unbedingt den "echten" Bohrlöchern entsprechen müssen, der Materialfluss entspricht zu jedem Zeitpunkt dem historischen. Wenn es nicht möglich ist Pseudo-Bohrlöcher im Modell zu platzieren ist das statische Modell falsch und muss ausgetauscht werden. Stochastische Realisationen können bereits von Anfang an überprüft werden. Zusätzliche Bohrlöcher injizieren Wasser an den Modellgrenzen, wodurch der mittlere Druck in jeder Region im Modell dem historischen Druck entspricht. Nachdem die historischen Raten und Drücke mithilfe der Pseudo-Bohrlöcher nachgestellt werden können werden die Pseudo-Bohrlöcher durch die echten Bohrlöcher ersetzt. Die Lagerstätteneigenschaften und die Perforationen werden schrittweise aufeinander abgestimmt. Dieses Tuning erfolgt teilweise automatisch, teilweise händisch, wobei das Programm Vorschläge für den Softwareanwender ausschreibt. Der History Matching Prozess ist abgeschlossen sobald alle Pseudo-Bohrlöcher durch "echte" ersetzt worden sind.

Pars Reservoir Simulator (PRS) ist eine nicht-kommerzielle, benutzerfreundliche Lagerstättensimulationssoftware, welche einerseits unabhängig, andererseits als Vorprozessor von ECLIPSE benutzt werden kann. Dem ECLIPSE Input werden einige Kommandozeilen hinzugefügt. PRS generiert eine modifizierte SCHEDULE Datei, die im folgenden ECLIPSE Simulationslauf verwendet wird. Diese enthält die aktuellen Einstellungen der Pseudo-Bohrlöcher sowie die Parameter für analytische Fetkovitch oder Carter-Tracey Grundwasserleiter Modelle, welche die Wasserinjektion an den Modellgrenzen ersetzen.

Die vorliegende Arbeit beinhaltet neben den für PRS entwickelten Methoden und Algorithmen ein Fallbeispiel einer Lagerstätte mit 700 Mio. stb Originalvolumen, 60 Bohrlöchern und einer Produktionszeit von mehr als 45 Jahren.

Abstract

A New Approach to History Matching of Water Driven Oil Reservoirs

by Fathe A.S. Abrahem

This dissertation presents a new technique for history matching. In the conventional approach the model wells are fixed and one seeks for a reservoir model in which they provide the historical rates, well pressures, WC and GOR over the entire time. The presented method does the opposite, the reservoir model is given and the computer places automatically wells which can do what they should do. These pseudo wells are perhaps at different location and open also other layers than the real wells but the overall material transfer will be correct for all the time. If such wells can not be placed, then the static model is fundamentally wrong and must be replaced. Stochastic realisations can be screened at this level already. Supplementary pseudo wells inject water to the model boundaries, assuring that the average pressure in any chosen region closely follows the historical pressure. After the global match succeeded, the pseudo wells are shifted toward the real ones and the reservoir and perforation properties will be tuned step by step, partly automatically partly manually. For the second one the procedure writes suggestions for the user. The HM is completed after all pseudo wells are replaced by the real wells.

Pars Reservoir Simulator (PRS) is a fully developed not commercial user friendly tool which can be used stand alone but also as a certain kind of pre-processor to ECLIPSE. The tool needs some command lines added to ECLIPSE input only. PRS write out a modified SCHEDULE file containing the actual settings of the pseudo wells and the parameters for the Fetkovich and Carter-Tracy analytical aquifer models (replacing the boundary injections) for the next ECLIPSE run.

Beside the methods and algorithm used in PRS the work present a full field application. The reservoir contains 700 MMstb OOIP and it was operated by 60 wells over 45 years.

Notes

The dissertation was issued in two versions, both in 5 numbered copies. The first one is the original version containing proprietary data and information of the following companies:

National Oil Company, Tripoli, Libya
Arabian Gulf Oil Company, Benghazi, Libya
Heinemann Oil Gmbh, Leoben, Austria

The second version was neutralized; numbers as geographic coordinates, reserves, production data, etc. has been erased and field, formation, etc. names has been changed. These changes do not hamper the scientific evaluation of the work.

ECLIPSE, CPS-3, GeoFrame 3D and Petrel are copyrighted by Schlumberger Ltd.

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SURE,SUREGrid are copyrighted by SST Simulation Software Technology GmbH

Chapter 1

Chapter 2

Chapter 3

List of Figures

List of Tables

Chapter 1

Introduction

1.1 Motivation of Work

Numerical methods are fundamental tools to evaluate, develop and optimize production from hydrocarbon reservoirs. These methods are used in two different ways, as modeling and as simulation tools. In both cases the models must be validated. One possibility for that is the History Matching, an alternative by modeling and an obligation while simulating.

Historically, geological modeling resulted in one single static reservoir model. The standard workflow used in the petroleum industry is to generate one dynamic model based on the single static reservoir model. This was done in a step-by-step procedure by modifying the dynamic model until measured field data fits within acceptable limits to the output of the dynamic reservoir model achieved with a reservoir simulator. This is called history matching. History Matching of large reservoirs with a great number of wells and long production time is a tedious work, in many cases without satisfactory results. The resulting model could be quite different to the static model which was used as the starting point of whole tuning procedure.

Many authors argued against this traditional practice, which normally ends up in two different reservoir models: the static and dynamic one. Aziz and Heinemann[5] suggested to avoid any parameter change in the dynamic model, which is normally upscaled from one static model realization, but rather to validate the static model(s) on the bases of dynamic data. They suggested not to speak about, and not to do, *history matching,* but rather talk about *dynamic conditioning* of the shared reservoir model(s). Figure 2.2 displays this concept. This dynamic conditioning should show which geological realizations can be accepted and which not. The fine tuning of the reservoir parameters should be done within the selected realization(s) and validated with the upscaled dynamic model(s). The suggested work flow is then a closed loop ending up in the validated (~~i.e.:~~ history matched) reservoir model(s). The supplement "s" indicates that the procedure can result in more than one dynamic model, based on different realizations and having different grid sizes. Aziz and Heinemann[5] believed that it will be possible to converge the two approaches; i.e.: to construct reservoir models applicable to modeling and simulation purposes. Heinemann[26] see the reason why this would not be achieved in the unpretentiousness of the oil producing industry and the dullness of the technology providers.

The motivation for this work is to move the Aziz-Heinemann[5] concept ahead (at least one small step), and to reduce the time and cost of the model validation and history matching work. The author of this work and his colleagues presented more and perhaps better ideas to enhance the reservoir modeling techniques, but what has no chance to become "ready-to-use" and industrially applicable in the near future, was not considered. Ready to use; what does it mean?

- The new solution should not require supplementary research or development before applying it, and it should fit today's existing technology. Regarding the reservoir modeling area this is PETREL and the simulator ECLIPSE.
- The new solution should be developed on real cases and not only demonstrated on models as the SPE comparative examples.

The ideal would be, if the results of the two approaches converge and at the end of the day the user would have only one reservoir model; the same for modeling (for analysis and explanation) and for simulation (for forecasts). This will not be achieved in this work, and also the Aziz and Heinemann[5] concept will not be realized. For that purpose a new generation of numerical methods should be used, which are more or less known and approved but not available commercially. What is even more critical, is, that they are not supported by the market leader geological modeling systems as PETREL or RMS and the more sophisticated tools as SUREGrid[32], GOCAD and EMpower found limited acceptance so far. Some of them should be also mentioned here: unstructured grid, time-depending grid, merged streamline and CVFD methods, windowing technique and last but not least the grided well bore.

1.2 The Objectives

The objective of this work is therefore more modest: the improvement and further development of the successful used Target Pressure Method (TPM) to a Target Pressure & Phase Method (TPPM). This development should lead to a tool and to a workflow which assure more reliable and faster selection of suitable model realizations, make the history matching process more straightforward and at the end more economical.

The tenets of TPPM approach are threefold:

- Instead of the wells their, drainage areas (volumes) will be regarded as production units. Every drainage area should produce the same amount of oil, water and gas as its real well, presuming that they exist as mobile phases at any time within the volume.
- TPM should be used to assure the correct (i.e.: historical) pressure development in all volume regions.
- The existence of the mobile phases necessary any time within drainage volumes is a criterion for the rightness of the static geological model and

must be assured before the detailed matching or model validation (i.e.: on well by well bases) starts.

Volume sources (i.e.: perforations or well connections) can be placed in any block within a drainage area, but the real perforations should be defined as sources in any case. The supplementary sources (pseudo perforations) could be placed preferably on the extension of the well trajectory but also anywhere else.

One of the weaknesses of the original A&H concept was, that the static model does not cover the outer aquifer and therefore can not count for the water inflow. Based on the idea of Heinemann, Pichelbauer and Mittermeir[42,44,51] developed an automatic procedure which solves this problem. This procedure is called Target Pressure Method (TPM). In this concept the reservoir is divided into regions for which the historical average pressures, as function of the time, are given. For some of those regions an outer boundary will be assigned. Water will be injected in this boundary assuring that the region pressure tightly follows the target pressure. At the end of the run the cumulative water inflow for each boundary is available. On this bases the parameters of the best fitting analytical aquifer model can be assessed.

TPM assumes that the model is able to produce the same reservoir volume as in reality over the entire production period. This can be approximated by definition of the target production rate in reservoir volume or in wet (gross) production. Such a setup works very well in cases producing minor amounts of associated phases, e.g.: gas reservoirs or oil reservoirs before water and gas break trough. In other cases the method is still superior to the simple try-and-error approach, but still needs some adjustment steps.

It should be emphasized that satisfactory fitting of the average pressure and overall produced volume on a region by region bases is already a good quality indicator for the reservoir geological model, but certainly not a proof. It can easily happen that one model well produces half of the amount of oil and double the amount of water or gas as in the history. That means, that it is necessary to improve the Pressure Target Method considering the distribution of the phases within the reservoir. This means that as a result of dynamic model conditioning, not only the average pressure and the water influx should be matched but also the oil, water and gas production. Naturally, not on a well by well but on a spot by spot bases.

Under a match on spot by spot bases one should understand, that oil, water and gas production from each drainage area should be equal to the historical ones. It is still not the final goal to achieve a well by well match. For that, local circumstances such as well as trajectory, perforations, skin, anisotropic, natural or induced fractures, e.t.c. must be considered.

It should be mentioned, that it is not necessary to match all the wells in every detail. In many cases a certain number of wells have been producing over a limited time only. For that the matching requirement can be different. It is not so important, that the model well works as the historical one but it is essential, that the cumulative oil, water and gas production is the same as in the reality. In such a case not only the pressure but the phase distribution is globally captured.

1.3 The Approach

The research and development was conducted in close connection with real field projects. The new developments were used in parallel to the standard methods, always ready to throw away the new idea, if it would not satisfy the expectations with regards to quality and efficiency, naturally under the time constraint of the project. This dualism gives the possibility for certain control, also if it is known that the standard method is not the best in every respect.

The top-down approach fundamentally differs from the usual bottom-up approach. With the second one the results are practically applicable (if any) at the end of the work only, in the top-down approach, after every step. The path of development starts at the specific case and will be generalized step by step. The structure of this thesis mirrors the top-down approach.

The reservoir modeling starts with the geological description, resulting in a parametrized geogrid. This model provides the static information including the amounts of fluid in place. The dynamic information is the production statistics and the historical pressures. Two methods can and will be used:

- **Material Balance Calculation (MBC)** which can assume a multi-tank system too (compartments). The production rates are given for all components (in black oil terms oil, gas and water) without defining the location of the sources and without considering the mobility ratio of the phases. The material balance also estimates the water inflow.
- **Decline Curve Analysis (DCA)** is used to predict the well rates, WC and sometimes the GOR on the bases of historical data.

The Target Pressure and Phase Method (TPPM) does the same as the MB and DC method but integrated in a single model and work flow. It maintains considerable more underlying information; including the entire geo-grid. After the TPPM the pressures are matched for all regions (compartments) and the well spots provide the historical oil, water and gas production. In many cases this result is sufficient bases for strategical decisions. But it is also an ideal status for all further ambitions. TPPM can be seen as an improved and integrated MB/DC method or a preparatory step for the conventional reservoir simulation.

The TPPM was developed on the bases and used in the following field studies:

1. Maros, gas reservoir, UGS, Hungary, operated by E'ON, 2008.
2. Kotla, oil reservoir, Libya, operated by Agoco, 2008-2009.
3. AHM, oil field, Libya, operated by Akakus, 2009
4. North Gialo and Farigh, oil field, operated by WAHA and ConnocoPhilips, 2009

The studies were carried out by Heinemann Oil Gmbh, Leoben (HOL). Based on private request Agoco permitted to use Kotla data for this PhD research work conducted in parallel but independently from the studies. The other field data was not made available, but HOL experts gave valuable feedback while applying TPPM also for these studies.

It is important to mention that the five fields are fundamentally different stating the general applicability of TPPM.

1.4 Software Tools

Most of the companies request to use the simulator ECLIPSE from Schlumberger[58]. This is the major burden for all research and development ambitions in the area of reservoir modeling. On one hand it is not possible to introduce new solutions into ECLIPSE or even find out how a given option is implemented in it, on the other hand nobody can develop a new software system equipped with all necessary options, user friendliness and being widely tested.

The author of this work was in the fortunate situation to have access to two software packages: PRS and ECLIPSE was used in parallel. The source code of PRS was available, so it was possible to introduce new procedures and make modifications in the existing modules. The software development was done on the author's request by the PRS software support team. HOL used also the two simulation software programs in parallel.

PRS, is a proprietary software of Professor Heinemann[25]. It operates on ECLIPSE input too, without any changes. This means that two identical runs on ECLIPSE and PRS can be started parallel every time and the results will be close to each other.

Some reservoir, aquifer and well parameters, e.g.: analytical aquifers and well PI's, will be automatically determined by PRS. With ECLIPSE the same could be done by trial and error only, which may be more time consuming. The updated parameters will be written out together with the appropriate ECLIPSE keywords and format (e.g.: BOX, MULTIPLY, WPIMULT etc.) and introduced in ECLIPSE data deck via INCLUDE or via the preprocessor SCHEDULE.

In usual cases the PRS and ECLIPSE results are close to each other and no, or little fine tuning on the ECLIPSE models is required. In the case of Kotla the differences in the history matched models are visible, but regarding the main two questions the two models are equally good.

1.5 Outline

Chapter 2 gives some background information about the author's view and understanding regarding selected topics: (1) Difference between modeling and simulation; (2) What is History Matching; (3) Automatic and computer assisted HM; (4) Aquifer modeling; (5) Target Pressure Method (TPM) and the determination of the optimal analytical aquifer parameters. Also some improvement to the basic methods will be suggested.

Chapter 3 presents the reservoir modeling workflow, based on the concept of TPPM. This is the main part of the dissertation.

Chapter 4 describes a full field example on which the TPPM was developed.

Chapter 5 is the implementation and validation of the TPPM method. It describes the handling of the pseudo wells and its relation to the corresponding real well. It will be presented how the pseudo wells can be used to match near well properties, as fractures and coning behaviors.

Chapter 6 summarizes the result of the full field history match. The TPPM workflow will be compared with the classical approach to determine the applicability and advantages.

Chapter 7 gives a summary and the conclusions of the presented work

Chapter 8 displays the list of the cited reference literature

Chapter 9 explains symbols and abreviations used in this work.

Appendix C contains some information about the quality of the well by well history matching.

The author tried to keep the chapters more or less independent to enable their use on a stand-alone basis (with or without smaller changes). For this reason some redundancy (e.g.: repetition of paragraphs, the same figure twice) is knowingly applied.

1.6 Scientific Achievements and Technical Contributions

The author's scientific ideas, achivements and his contributions to future technology can be summarized as follows:

1. **New ideas presented in this work:**

   - The author presents in this work his own new idea and approach to history matching called "Target Pressure and Phase Method", shortly TPPM. The definition of approch and the explanation the difference between TPPM and TPM is given at the beginning of Chapter 3.
   - It is suggested to replace the objective of "well by well" match by the objective "spot by spot" match. The difficulties to describe the well and reservoir connection should not be solved by crushing and squeezing the reservoir, introducing deteriorate artefacts.
   - Nevertheless the TPPM can be combined with the classical HM approach making it a three step process, instead of two:

     global or conceptional modeling,

     spot-by-spot

     well-by-well history match.

2. **Documented scientific results**

   - The Target Pressure Method is workable in case of carbonate reservoirs with complex geological structure and a long production history. Pseudo wells and pseudo perforations can be used to counterbalance shortcomings in reservoir description and discretisation techniques assuring higher level predictive capability compared to the conventional well models. Main technical contributions of the work
   - The entire workflow of the TPPM was implemented and tested in the simulator PRS, designed and developed by Prof. Heinemann's research group. This software is industrially operational.
   - The applicability of this software tool was demonstrated in a case study. The field under consideration has 45 years production history and a cumulative production of 160 MMstb.
   - With PRS an efficient history matching tool becomes available. PRS can be used as a preprocessor to ECLIPSE.

1.7 Publications of the Author

The research and development work was made in 18 months. No publications were planned before the scientific work and the field applications were completed with success and are documented in this thesis. Supplementary the author needs the permission from the National Oil Corporation (NOC) to include the field results into the publications. The results will be published in the following conferences and journals:

Abrahem, F.S.A., Heinemann,Z.E. and Mittermeir, G.M.: "A new Computer Assisted History Matching Method" 2010 SPE Europec/EAGE Conference and Exhibition, Barcelona, 14-17 June 2010. (paper accepted).

Gherryo. Y.S., Shatwan, M., **Abrahem, F.S.A.**, Mittermeir, G.M. and Heinemann, Z.E.: "Application of a New Computer Aided History Matching Approach - A Successful Case Study," 2010 SPE North Africa Technical Conference and Exhibition, held in Cairo, Egyipt, 14-17 Feb. 2010. (paper submited).

Abrahem, F.S.A., Heinemann,Z.E.: "Successful Application of Automatic History Matching on Kotla Field, Libya, "Hungarian Journal of Mining and Metallurgie; OIL AND GAS, 2010 (in printing).

Chapter 2

Notes to Reservoir Modeling

2.1 Introduction

Douglas, *Peacemen* and *Rachford*[15] ran the first numerical reservoir simulator in 1958. During the last 50 years reservoir simulation became the basic tool of reservoir engineers, already tought on BSc level and used in practical work every day. The theory and practice is today common knowledge and obligatory skill. The objective of TPPM development work was not to contribute to the theory but to establish a work flow making the HM process more effective. The primary ambition was to do it on the basis of well known and widely used options and methods. Nevertheless the author felt that it is advantageous to document and discuss some selected topics in this thesis for his own understanding but also to minimize the risk of mutual misinterpretations. There are no new findings, even no new interpretations in this chapter but a summary about those, that the author learnt during his PhD work from the literature, from his advisor and research associates. The chapter contains the following sections:

Simulation versus mathematical modeling; Discussions with both academic and industrial persons showed that most of them do not clearly see the difference between mathematical modeling and simulation. This is an important question because TPPM is an approach to simulation and not to mathematical modeling. The discussion of this question is mostly based on the lectures, publications and private communications of and with *Zoltan E.Heinemann*[26].

History Matching is part of reservoir characterisation and evaluation. The HM should not be reduced to simple squeezing the geological model. The section is mostly based on the previous work of *Pichlbauer*[51] and *Mittelmeir*[42].

Automatic and computer assisted HM became popular expressions in the last decade. The question if TPPM can be counted to this class is often asked.

To be able to answer this question it is required to give an overview about those methods. The answer of the author is no. The section is a summary of the literature search performed.

Aquifer modeling is one of the focused elements in TPPM, therefore some detailed information about this topic should have their place in this work. The approach of PRS and ECLIPSE is different in this respect and need some explanations. A more detailed discussion about this topic is given in PRS Technical Description[29].

Target Pressure Method was one of the major research areas and development successes in the Petroleum Department of the Mining University Leoben during the years 2001-2004 resulting in the PhD thesis of *Pichlbauer*[51] and the MS theses of *Mittermeir*[44]. Since then, this method became industry standard.

2.2 Simulation versus Mathematical Modeling

To achieve a deep understanding and the most realistic forecast for a reservoir, mathematical modeling and numerical simulation will be performed. Colloquial the expression "reservoir simulation" will be used in both cases, probably due to the fact that the same tools are applied to similar problem. With other words the same model can be used in analytical mode and in simulation mode. The difference is also not in the model itself but in its use: the objectives and in the approach. It is important to understand this fundamental difference, especially when dealing with really difficult cases, where both approaches are applied complementary. Mathematical modeling is not a simulation and a simulation is not a mathematical modeling. The difference is shown in Figure 2.1.

No mathematical model can be complete. The mathematical formulae are more or less approximations of the physical phenomenon and furthermore often have to be simplified to be able to calculate with them. In most cases they reflect only the most important sides of reality. If a mathematical model was set up, only processes formulated in this model could be examined with it.

No geological model can represent a real reservoir in its full complexity. The geological models are more or less concepts from different aspects of the geological formation. So it is possible to speak about depositional, sequence stratigraphic, litho-stratigraphic, etc. models.

The reservoir model is the combination of the mathematical and the geological models inheriting the foible from both sides.

The same reservoir model can be used in two modes:

- as modeling tool (analytical mode),
- as simulation tool.

The correctness of a computation in analytical mode is guaranteed when the underlying equations are based on experimental evidence, when the calculations are mathematically correct and when it is performed on an idealized conceptual geological model. The result of such an analytical investigation describes an idealized system but not the existing real object. The differences between the reality and the models are valuable information and help the investigator to assess his mind and estimate the uncertainties in his decisions.

In the simulation mode the applicability of the reservoir model is proven by matching: the calculated results should be identical with the system behavior. The mathematical model is perhaps incomplete and the geological model is perhaps a subjective projection of the reality but the model matches the system. The tuning of the model, even if it has no physical explanation, is allowed. The "Ten Golden Rules for Similation Engineers" formulated by Aziz[4] should never be forgoten.

The analytical approach does not predict but explain. The simulation approach does not explain but predict. The petroleum engineering practice uses both approaches widely. The water cut of a well can be investigated by the Buckley-Leverett method (analytical approach) or predicted by decline curves (simulation approach).

A MATHEMATICAL MODEL
WITH SUITABLE
SOLVING METHODS
WHICH CAN BE
ANALYTICAL, NUMERICAL OR ANALOGOUS
IS USED

EITHER IN ANALYTICAL MODE		OR IN SIMULATION MODE
	IT REQUIRES	
THE EXPERIMENTAL EVIDENCE OF THE BASIC EQUATIONS AND CORRECT MATHEMATICAL CALCULATIONS		THE CONCISTANCE OF ITS BEHAVIOR WITH THE REAL SYSTEM (MATCHING)
	THE RESULTS	
ARE FINDINGS ON QUALITATIVE PROPERTIES AND COHERENCES		ARE THE PREDICTION OF THE BEHAVIOR
	AND ARE USED AS	
BASIS FOR DISCUSSION		BASIS FOR DECISION

Figure 2.1: Use mathematical models in analytical and simulation mode (after *Z.E.Heinemann*[27])

The nature of numerical simulation is demonstrated in Figure 2.2. It has two sides, a real and an imaginary one. The computer program, based on the mathematical model needs input. These data are measured on the object (e.g. reservoir), the parameters are matched so that one part of the output coincides with the observations on the object. A greater part of the output cannot be compared with observations, but gives hints about the possible stage of the object. They must be handled with care, also f the matching was successful.

The model cannot solve real problems in lack of reliable data and serious comparison. No simulator can replace reliable data or the brain of the user.

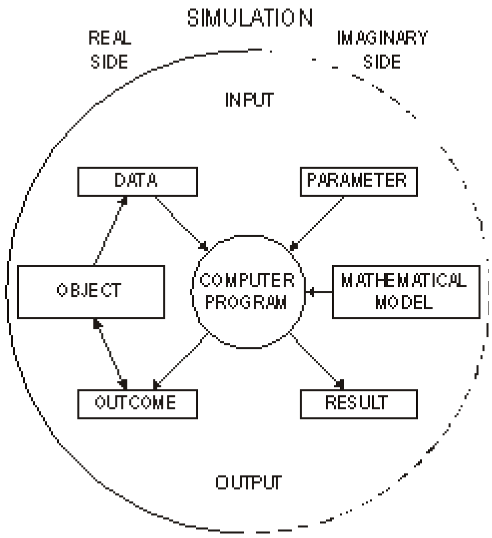

Figure 2.2: The nature of numerical simulation (after *Z.E.Heinemann*[27])

2.3 History Matching

2.3.1 What is It?

It is not possible to cover all aspects of the HM. It is not even possible to give a summary of today's stage of the History Matching Techniques, within the frame of this work. Standard History Matching Techniques are composed of a fixed geological model (Static Model) with global modifications and local adjustment. The limitations of this methodology are clear. Local adjustments are not always geologically realistic, static uncertainties are not taken into account and only a limited number of models are used for prediction.

To be fully understandable this traditional workflow is to generate one dynamic model based on the single static reservoir model. This was done by modifying the dynamic model until the dynamic model corresponded to the historic field data. This is called history matching. The resulting model could be quite different to the static model which was used at the starting point of whole tuning procedure. This traditional workflow is described by the chart displayed in Figure 2.3.

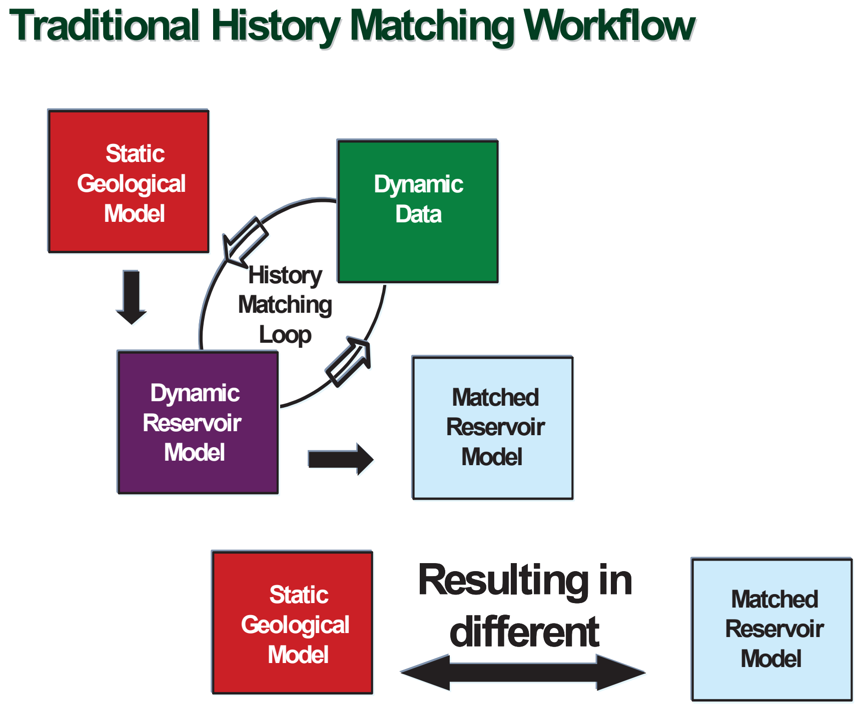

Figure 2.3: Standard Simulation Workflow

While the capabilities of geosciences improved onwards to create a very detailed and reliable static model due to improved 3D and cross-well seismic, data integration and stochastic modeling, another approach to reach a history matched dynamic model is feasible.

This new approach goes away from the task to generate one matched dynamic model based on one tuned static model. It shifts towards a fast and reliable verification of the numerous static models. In principle the task remains the same. This is to get one valid history matched dynamic model.

The new idea is to find the best fitting realization out of many, equally probable static models resulting from stochastic modeling. This new workflow is outlined in Figure 2.4.

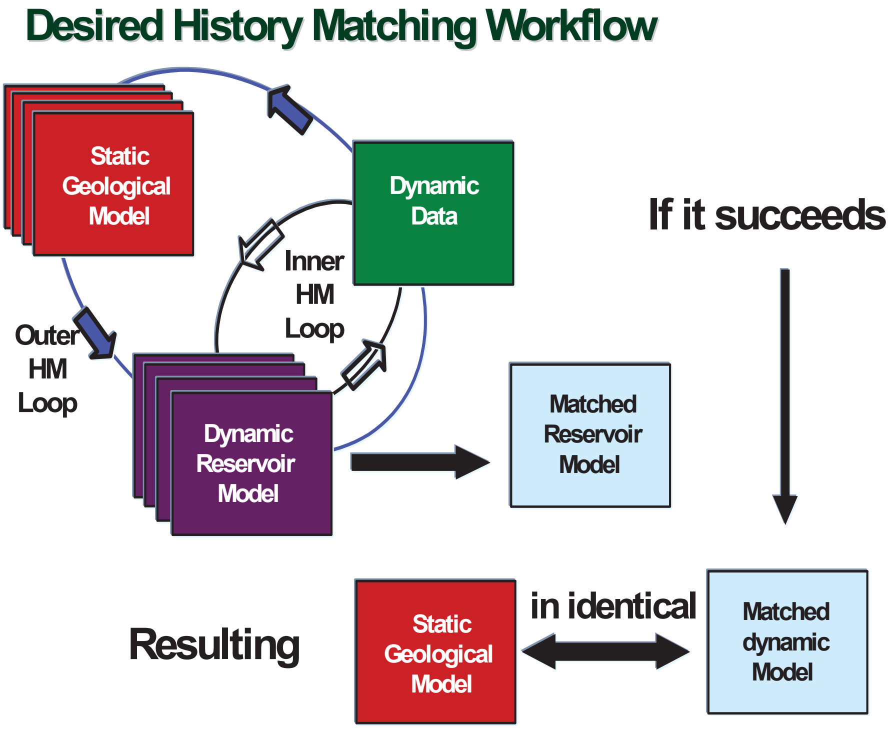

Figure 2.4: New Simulation Workflow

The classical approach in history matching is a step-by-step procedure altering the geological reservoir model until the output of the reservoir simulator fits to measured field data within acceptable limits.

This approach is shown in Figure 2.5. Note that the arrays are oriented from left to right, in principle any parameter may be adjusted.

Normally these parameters include permeabilities, porosities, fault transmissibillities and throws, aquifer strength, rock compressibility and initial fluid contact depths. Geological and petrophysical properties of the productive areas are well known through different geophysical and geostatistical methods.

History matching mainly deals with aquifer properties, since only few or even no data are available about this part of the reservoir model.

Throughout the process of history matching the aquifer model becomes more and more complex. This is done by re-sizing and re-parametrizing the grided aquifer or by changing the parameters of analytical aquifer models without changing the productive area.

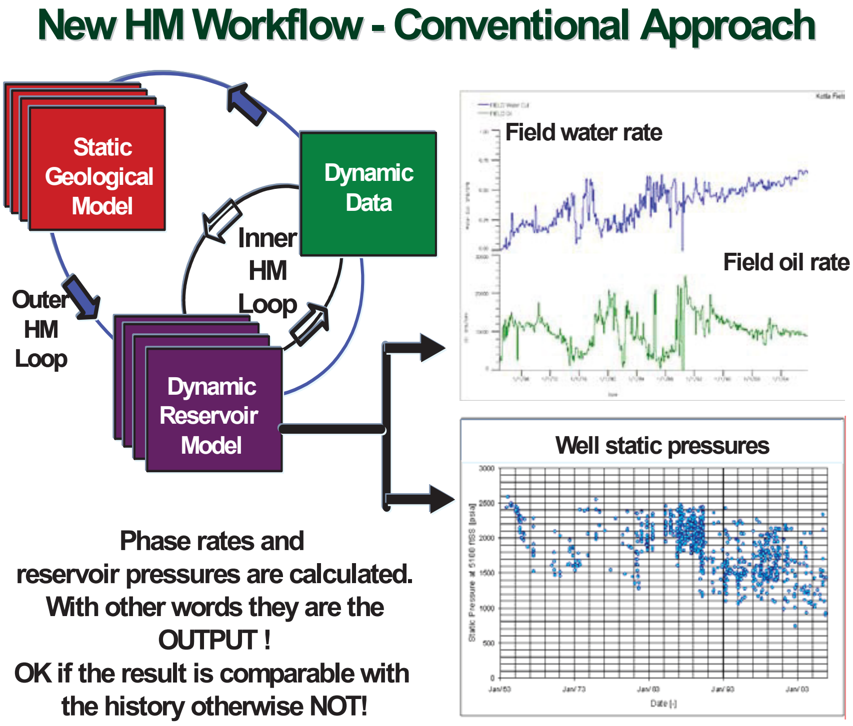

Figure 2.5: Validation of a dynamic resevoir model in a conventional approach

2.3.2 Quality of History Match

The results of the well by well HM are the static and dynamic BHP, the cumulative oil, water and gas production and the production rates at the end of the history.

Which items are more important in a given case depends on the quality of the data and of the geomodel, on the nature of reservoir, the depletion mechanisms and - very strongly - on the objective of the study.

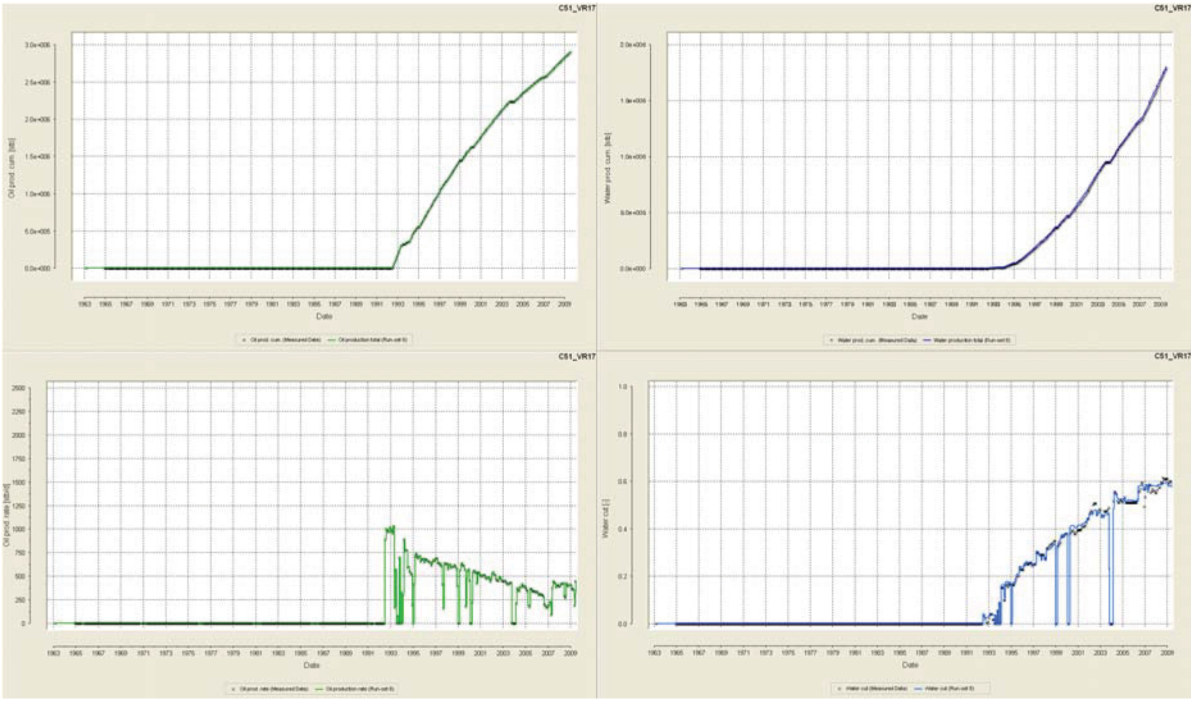

Figure 2.6: Both cumulative production and trend fit (well C51_VR17)

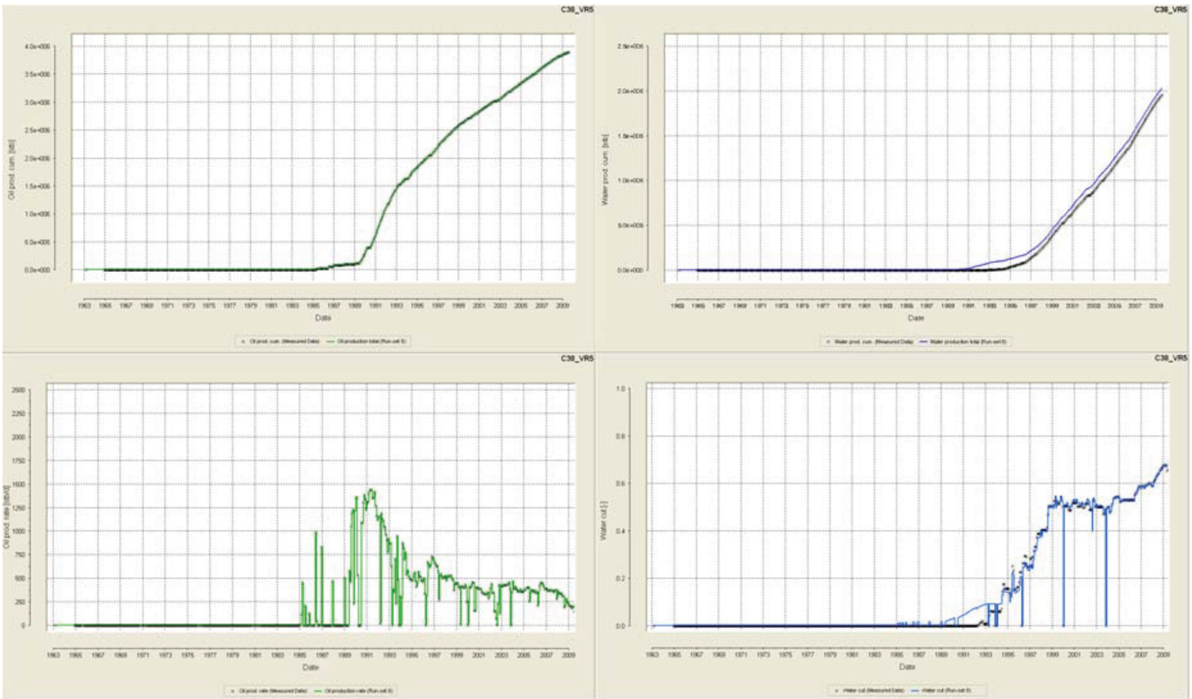

Figure 2.7: Cumulative production failed, trend fits (well C38_VR5)

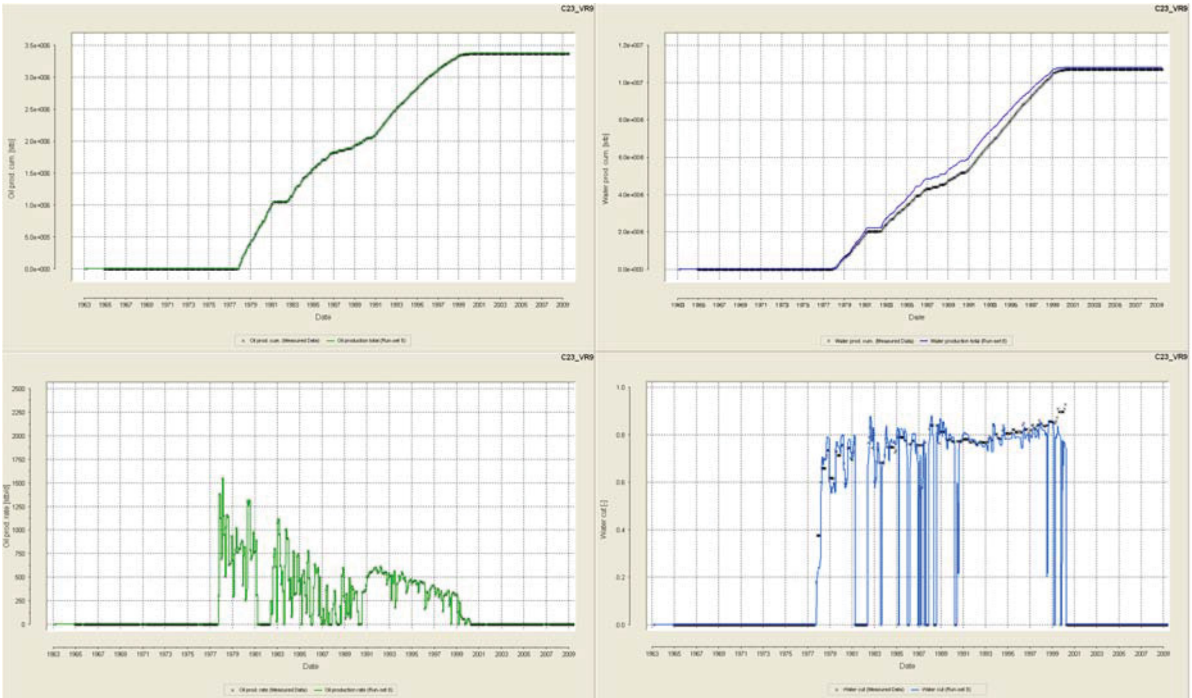

Figure 2.8: Cumulative production fits, trend failed (well C23_VR)

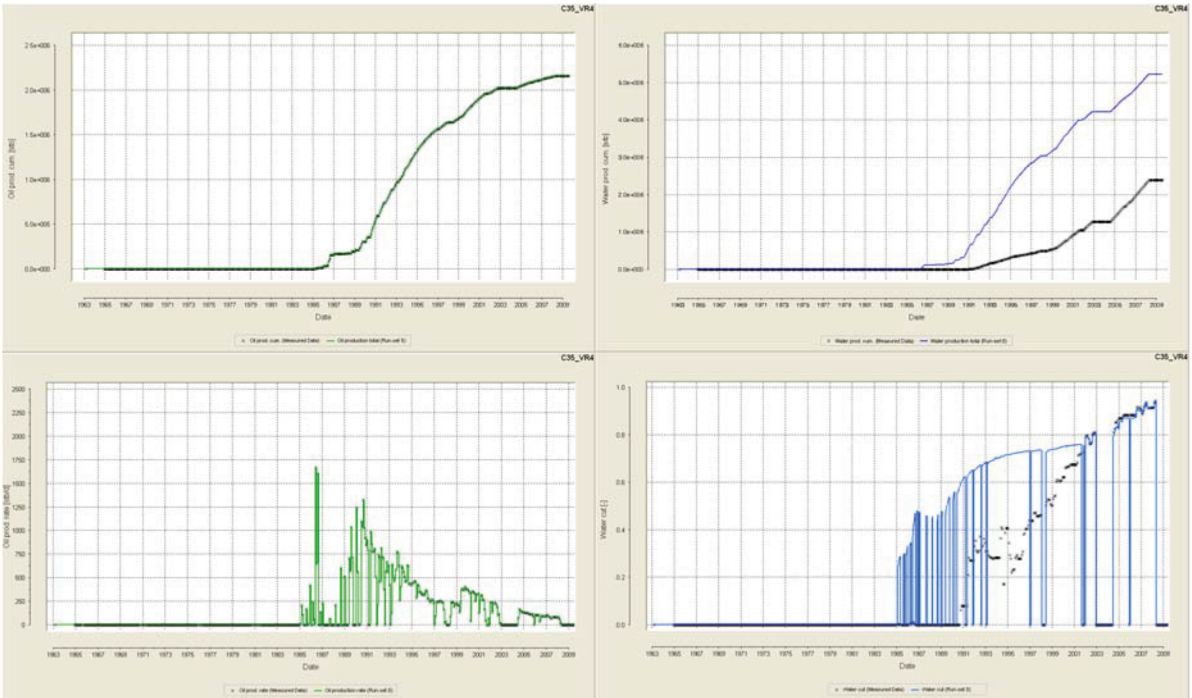

Figure 2.9: History match of the well failed (well C35_VR4)

Figure 2.6 to Figure 2.9 show wells "history matched" on different level. The figures are taken from a real project but serve here for demostration only.

Figure 2.6 shows an optimally matched well. The cumulative oil and water production is reproduced for the entire production period and the slope of the curves in the last years fit to the observations. Only the differences in the production rates are apparent. The historical data are given on monthly basis; the simulator uses the quarterly averages in sake of more flexibility in time step regulation and better numerical stability. If most of the wells are matched with this quality then two requirements of highest importance are satisfied:

- The correct amount of oil and water are located at every well drainage area all the time. Therefore it can be assumed that the distribution of the phases in the reservoir is modelled correctly and the place of the remaining oil is determined credibly. The model reproduces today's well productivity. Therefore the model can be used to predict the well and field performances.

Figure 2.7 and Figure 2.8 show two weakly matched cases. In the first case the cumulative production fits, but the match of today's trend failed. The second case is the opposite. The well in Figure 2.9 failed completely.

2.3.3 Automated and Computer Assisted History Matching

Basically history matching is done by a trial and error process that is mainly influenced by the experience, intuition and judgement of the simulation engineer, it can be a very time consuming and costly step in a standard simulation workflow. A good description of traditional history matching methods can be found in Williams et al.[65]. To improve the effectiveness of history matching and to automate, and therefore, shorten this costly step was the focus of the last years. The goal was and still is to find ways to an automated history matching by implementing different algorithms to find the minimum of a so called objective function. Such an objective function quantifies the differences between observed and simulated values.

One way of optimizing history matching is the use of the gradient method. Such a method was developed by *Anterion* et al.[3]. This method requires the derivatives of the components of the objective function with respect to the history matching parameters. This means that the reservoir engineer is able to test his ideas by making repeated simulation runs with altered parameters. If an improved match is achieved, he can guess - by applying the gradient method - how much the altered parameter have to be changed to get a matched model or matched part of the model. *Tan and Kalogerakis*[59,60] used this method to solve a model problem. *Bissell et al.*[7,8] applied it to real field cases.

A hybrid method where gradient optimization is combined with a direct search method was developed by *Leitato et al*.[37]. Additionally parallel computing was used to speed up the procedure. *Schiozer*[56] worked with an similar approach. The main achievements of both developments were the gained speed-up factors by using parallel computing.

Regarding effectiveness of finding and correctness of the parameters their work can be compared to other methods.

The gradient method has some shortcomings such as distortion of variograms characterizing the spatial distribution of two parameters like porosity and permeability if they are simultaneously updated. To overcome some of them, new ideas were intorduced.These were the combination of the gradient method with geostatistical parameterization techniques such as the pilot point method of *Bissell et al.*[7] or the gradual method of *Roggero et al.*[53].

Using genetic algorithms[40,49,52], simulated annealing techniques[39], neural networks or response surfaces[17] are other recent approaches how to deal with the minimization problem of history matching.

Until now, none of the techniques described above has gained a wide acceptance as a useful tool for history matching. According to *MacMillan et al.*[39] this results from the fact that all these methods assume that all the matching parameters have been determined and that the model is fixed. They further assume that the only thing is to adjust those parameters to get a matched model. As a way out *MacMillan et al.* developed tools to assist the simulation engineer to find the correct parameters and their needed modifications.

Emmanuel et al.[18] defined the term assisted history matching as using algorithmic techniques to assist the process of traditional history matching. They used the flowpath of 3D streamlines to assist the process of altering reservoir parameters. *Le Ravalec-Duoin and Fenwick*[38] also use the concept of streamlines. They combined it with geostatistical tools and the gradient method.

Also *Sarma at* al.[54] introduced a new approach to automatic History Matching using Kernel PCA; in this way they apply a new parameterization referred to as a kernel principal component analysis (kernel PCA or KPCA) to model permeability fields characterized by multipoint geostatistics.

Schulze-Riegert and *Shawket Ghedan*[57] presented in the 9th international forum on reservoir simulation a Modern Technique for History Matching, dealing with uncertainties in reservoir data. It is not within the scope of this thesis to give a historical overview or to discuss all advantages and limitations of alternative techniques but an extended reference list is added for this purpose.

TPPM is not comparable with all those methods from the simple reason that no reservoir parameters will be modified but the well position and perforation properties. From this respect TPPM opens a new classe of computer assested history matching methods.

2.4 Aquifer Models

2.4.1 Introduction and background information to Aquifer Modeling

Today's reservoir characterization, modeling, advanced well logging and interpretation methods, as well as modern production surveying and monitoring systems deliver more and more detailed information about the reservoir. The step-up in quality and quantity of data generally reduces the attempt of the date of the interview process, but all of these methods usually are not applied to the aquifer of the reservoir. As the aquifer is frequently not covered by modern reservoir modeling techniques, great uncertainty regarding the characterization and parameters are the result.

A large number of oil and gas reservoirs have an associated aquifer, that provides them with pressure support. The reservoir and the aquifer form a hydraulic system and a pressure decline accompanying production results in water encroachment into these reservoirs. The importance of this water movement derives from the significant dependence of production rate upon reservoir pressure, in turn, upon water encroachment. For this reason a successful simulation study is only possible if the complete system, reservoir and aquifer, is taken into consideration and not only the hydrocarbon bearing part.

Fundamentally there are two possibilities to model the water inflow into a reservoir:

1. Representing the aquifer by a grid model
2. Using analytical models

According to *Heinemann*[22] a reservoir model can be built from two fundamentally different domains. One is the reservoir itself, the other one is the connected outer aquifer. The grids for these domains are constructed independently but are combined to one full field project. This results in an *Aquifer Grid* and in a *Productive Area* grid. In *Heinemann's* concept "reservoir" and productive area (PA) have slightly different meanings, because the PA normally covers a part of the water bearing formations too, called inner aquifer. As already mentioned the PA and the Aquifer are modeled by independent grids, which can be linked to each other, or with other words, they can be merged into one single grid model.

Most of the commercial modeling packages do not make this splitting. The whole grid will be constructed in one step. In such a case the PA grid can be created by deactivating the aquifer grid blocks and the aquifer grid by deactivating the reservoir grid blocks.

This chapter deals with both kinds of aquifer models. The splitting of the model in PA and Aquifer grid has the advantage that for a given PA, both a gridded as well as an analytical aquifer model, can be used. The combination of the two methods provides considerable advantages for the history matching especially aquifer matching, as will be shown throughout this thesis. In this chapter the basic methods will be introduced. It will be shown that the two methods, using them in the right way, provide comparable results.

2.4.2 Gridded Aquifer Models

While the geological and petrophysical properties of the productive areas are known at the beginning of a simulation project, the aquifer is usually unknown. The size, the porosity, the permeability and their distributions around the productive area will be determined by matching reservoir pressure. In lack of other possibility the aquifer is regarding isotropic in areal extension, i.e.: the permeability does not depend on the direction. The History Match is a step-by-step procedure in which the aquifer model becomes more and more complex by re-sizing and re-parametrization of the aquifer without changing the productive area, The aquifer grid is constructed from the global mesh outside the PA, (full explanation in Appendix 5)

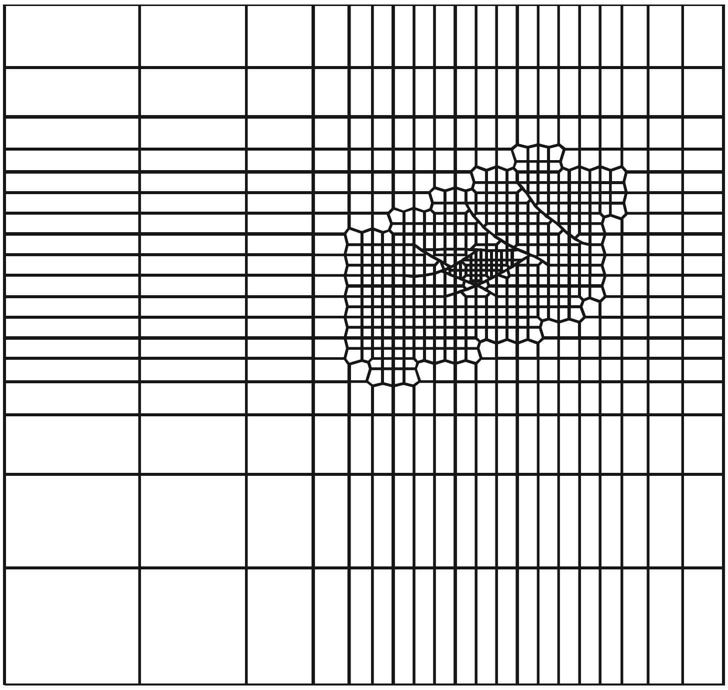

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Figure 2.10: Simulation model with gridded aquifer (after Heinemann[22])

2.4.3 Analytical Aquifer Modeling

2.4.3.1 Aquifer Models

Because of the recognition that the reservoir and the aquifer form a hydrodynamic system, it became necessary to find methods to relate aquifer behavior and reservoir response. The first dependencies have been developed in the 1930’s by using material balance formulations.

The dominance of material balance calculations for determining aquifer behavior became less in the 1960’s when numerical reservoir simulation became more and more usable. These achievements lead to an integration of water influx calculations and as a result more sophisticated techniques were found. Outside numerical reservoir simulation most water influx calculations are based on aquifer behavior models. Theses models describe how the aquifer responds to changes in the reservoir. This response is expressed as a water influx rate. Assuming an aquifer behavior model with an analytical solution is common practice.

To establish aquifer models two different approaches can be used, the first is to establish a model based on idealized mathematical models, these models are idealized so far as they assume homogeneous reservoir properties like uniform porosity, permeability, etc, but these models are also idealized in another way, concerning reservoir and flow geometry. This idealization is expressed either by radial or linear models.

The second approach to develop aquifer behavior models is based on a direct integration of field data, this leads to models without idealized assumptions concerning homogeneities and geometries. In 1936 *Schilthuis*[55] published a model according to the first approach described above.

Schilthuis developed a model for steady-state water influx behavior, this means that this model is applicable if the aquifer is of such an extent that water influx to the reservoir does not alter the aquifer pressure observably, this would correspond to an aquifer of infinite dimensions. Since the size of an aquifer is usually limited this method is only applicable in a few cases.

To describe aquifers that change their pressure over time it became necessary to develop aquifer behavior models that take into consideration this non steady state water influx. *Hurst and VanEverdingen*[62] in 1943 and *Carslaw and Jaeger*[11] in 1959 have developed such models based on the solution of the differential diffusivity equation. The solution presented by *Carslaw and Jaeger* is valid for linear aquifers whereas the solution of *Hurst and VanEverdingen*[63] is valid for radial symmetrical geometries. Both methods have two disadvantages in common. The first is that they do not support an analytical solution to solve water influx problems of aquifers with arbitrary shape. The second is that both methods use the principle of superposition to allow a time dependent reservoir boundary pressure. Therefore, their methods result in a lengthly and tedious calculation for increasing time steps.

In 1987 *Vogt and Wang*[64] published an improvement to the model of *Hurst and VanEverdingen*[63]. This was done by substituting the stepwise constant reservoir-aquifer boundary pressure - used by *Hurst and VanEverdingen*[63] to apply the principle of superposition - by a piecewise linear one. Besides gaining better results if the pressure changes quickly especially at early times another advantages is inherent to the *Hurst and*

VanEverdingen[63] method. This is that the piece-wise linear approximation is more convenient for computer programming.

To avoid the unpleasantness related to the principle of superposition *Carter and Tracy*[10] proposed a method in 1960 to solve water influx calculations for transient circular aquifer models analytically based on the solution of *Hurst and VanEverdingen*. They assumed constant water influx for any given time step. Since this is not strictly valid, their method is not as accurate as the one by *Hurst and VanEverdingen*.

All aquifer behavior models for non steady-state water influx mentioned above have in common that they are restricted to regular shaped reservoir and aquifer boundaries. For complex water influx geometries *Numbere*[48] developed a method in 1989. This method allows to calculate a dimensionless influx function for complicated geometries of reservoirs as well as aquifers. *Katz et al.*[35] as well as *Carter and Tracy*[10] have chosen the same approach for other reservoir studies. They showed with their publications the validity and utility of the method of *Numbere*[48] but also extended this method to additional reservoir-aquifer geometries resulting in additional tables.

In 1969 *Fetkovich*[19] published a different approach of how to deal with the water influx problem without knowing the reservoir aquifer geometry. The developed model is largely empirical and assumes a pseudo steady-state flow behavior. This means a finite aquifer with a short transient period. Because of its empirical character no guidelines when this model is applicable can be given.

The second approach to establish aquifer behavior models is to use direct field data. Therefore, such models are only valid for a particular aquifer-reservoir combination. Using this approach, an influence function *F(t)* is established which links water movement uniquely to a reservoir aquifer combination. Since this influence function is based on direct field data a consideration of heterogeneity and geometry can take place. *Hutchinson and Sikora*[34] and *Katz, Tek and Jones*[35] dealt with aquifer influence functions. They encountered difficulties if the field data showed inaccuracies.

A general theory for aquifer behavior was developed by *Coats, Rapaport, McCord and Drews*[12] in 1964. Their theory was based on a general aquifer that was heterogeneous, arbitrarily shaped and that had rock properties such as permeability, porosity and total compressibility that were independent of pressure. They showed that the general solution to this problem can be described using infinite series. Using infinite series the three basic flow behaviors of aquifers (steady-state, none steady-state and pseudo steady-state) are only special cases of their general formulation. The method of *Coats et al.*[12] was extended and improved later by various studies.

Still, all these models and improvements share one general drawback. They are dependent on an estimate for the water influx to match the aquifer influence function.

2.4.3.2 Inflow into the Artificial Boundaries

Fluid flow processes in reservoirs are simulated by using discretized forms of partial differential equations. They result from the combination of balance equations describing the conservation of mass and Darcy's law. These equations linking fluid flow rate, pressure, reservoir and fluid properties are of mixed hyperbolic-parabolic type. Along with appropriate constraints, constitutive relations, boundary and initial conditions the discretized forms of the partial differential equations can be solved numerically.

Amado et al.[2] derived a general implicit mole balance equation using the *Control Volume Finite Difference* (CVFD) discretization scheme given in Equation 2.1. This formulation consists of the *flow* or *convection* term on the left-hand side and the *accumulation* term on the right-hand side only. The *source/sink* term, expressed by Equation 2.2 can be added to the left hand side whenever necessary.

$$\sum_{j=1}^{N} \sum_{p=1}^{P} \tau_{ij}(\lambda_p D_p x_{pc})_{ij}^{n+1} (\Phi_{pj} - \Phi_{pi})^{n+1} = \frac{V_i}{\Delta t} \Delta_t \left[\phi \sum_{p=1}^{P} (S_p D_p x_{pc}) \right]_i \tag{2.1}$$

$$\sum_{p=1}^{P} (q_p x_{pc})_I^{n+1} , \tag{2.2}$$

where

t_{ij}	blockpair transmissibility [Darcy.m]
x_{pc}	mole fraction of component *c* in phase *p* [-]
l_p	mobility of the phase *p* [cp^{-1}]
D_p	specific mole density [$kmol/m^3$]
n	number of time steps [-]
q_p	source/sink term for phase *p* [kmol/day]
D_t	time step [day]
V_i	volume of grid block *I* [m^3]
f	porosity [-]
S_p	phase saturation [-]

and the indices limits are

P	number of phases
C	number of components
N	number of neighboring grid points for point *i*.

Various types of boundary conditions can be defined. Boundaries used in reservoir simulation can be classified generally either as inner or outer boundaries. Outer boundaries are the top and the bottom of the domain, as well as the outer delimitation lines (surfaces). Examples for inner boundaries are discontinuity lines (surfaces) such as faults. The major difference between outer and inner boundaries is, while the outer boundary has one side only, the inner boundary separates or connects two different domains (or subdomains).

For outer boundaries two types of conditions can be applied. Boundary conditions of *Dirichlet type* (Equation 2.3) define the potential at the boundary and boundary conditions of *von Neumann type* (Equation 2.4) define the flow rate across it.

$$\Phi = \Phi_{\Gamma}(t) \tag{2.3}$$

$$u_{p\Gamma}(t) = -\lambda_p \bar{\bar{k}} \nabla \Phi_p \vec{n}_{\Gamma} \tag{2.4}$$

If the boundary is sealing (no-flow boundary) then $u_{p\Gamma} = 0$ is valid.

Inner boundaries are characterized by the *flux continuity condition* given by Equation 2.5.

$$\bar{\bar{k}}_{ir} \nabla \Phi_{ir} \vec{n}_i = \bar{\bar{k}}_{il} \nabla \Phi_{il} \vec{n}_i, \tag{2.5}$$

where

$\bar{\bar{k}}$	permeability tensor [Darcy]
$\vec{n}$	normal unit vector [m]
t	time [s]
$\vec{u}$	filtration velocity [m/s]
F	phase potential [Pa]
l	phase mobility [1/Pas]
p	phase
G	boundary

and the indices *ir* and *il* denote the right- and left-hand sides of the discontinuity surface.

In work of *Pichlbauer*[51] the concept of *Artificial Boundaries* (AB) is introduced. Artificial boundaries can, but do not have to, have something in common with natural boundaries, defined above. From a mathematical aspect they are not boundaries, because no boundary conditions will be applied to them. An Artificial Boundary is built by an arbitrary row of blocks, representing a line or a surface anywhere in the grid model.

Artificial Boundaries will be used as tools to enhance the modeling process, mostly the History Matching process. For an already existing grid model it is possible to define one or more of such boundaries. This kind of "boundaries" is characterized by supplementary source/sink terms, which means, that fluid can be injected in, or produced from these blocks under defined conditions. These source/sink terms can be cancelled anytime. This means that the former boundary blocks become “normal” blocks again. With other words, once an artificial boundary is defined, it can be activated or deactivated. An artificial boundary can have neighboring blocks on one side only. Then one speaks about an Outer Artificial Boundary or on both sides, representing an Inner Artificial Boundary.

- A grid block can belong to one boundary only. This implies that boundaries cannot intersect with each other.
- A boundary can be discontinuous. A boundary may be split up into several parts, disconnected through pinched-out blocks or regions without aquifer-reservoir connection.

Theoretically, any kind of fluid could be injected into or produced from the artificial boundary blocks but for practical reasons a restriction to the water phase is done. Consequently both outer and inner artificial boundaries will be defined within the water bearing parts of a grid model only. Artificial boundaries can be defined automatically, based on model properties, or can be set manually by the user. The following examples should give an idea about the artificial boundary concept.

2.4.3.3 Implementation in Grid Model

The boundary between the Productive Area and the Aquifer can be understood as an inner or as an outer boundary, depending on the way how the model will be operated. The operating conditions for the boundary can be defined from the reservoir side, from the aquifer side or from both sides.

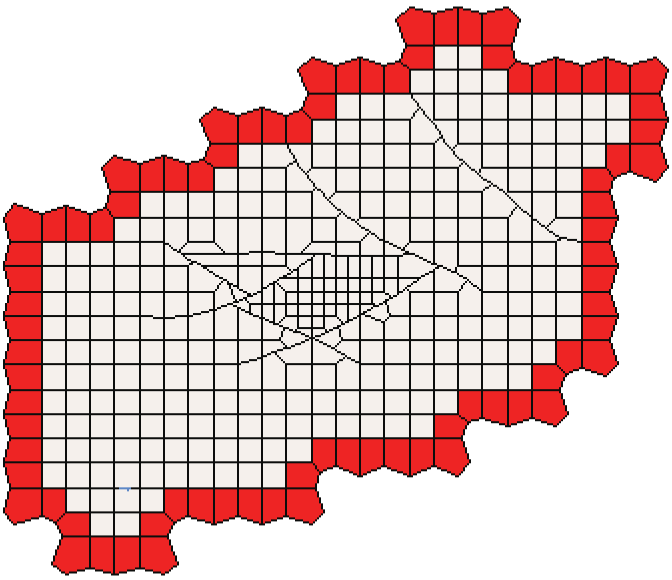

Figure 2.11: Grid model of a Productive Area (from *HOT SURE manual*[31])

Figure 2.11 shows the grid of a productive area. The artificial boundary is now formed by the outermost grid blocks, and is defined by definition within the model construction process. This boundary connects the PA grid to the aquifer grid, or the boundary blocks serve as entry points for the water influx, calculated from an analytical aquifer model. In the first case the artificial boundary is an inner boundary, in the second case an outer boundary.

The boundary does not have to be continuous for the whole PA. It is possible to split it up into more segments. The splitting has the advantage that different conditions can be defined for each part of the reservoir. In Figure 2.12. the gridded reservoir area is surrounded by three outer boundaries. Naturally it is possible that a grid model has a boundary on one side only.

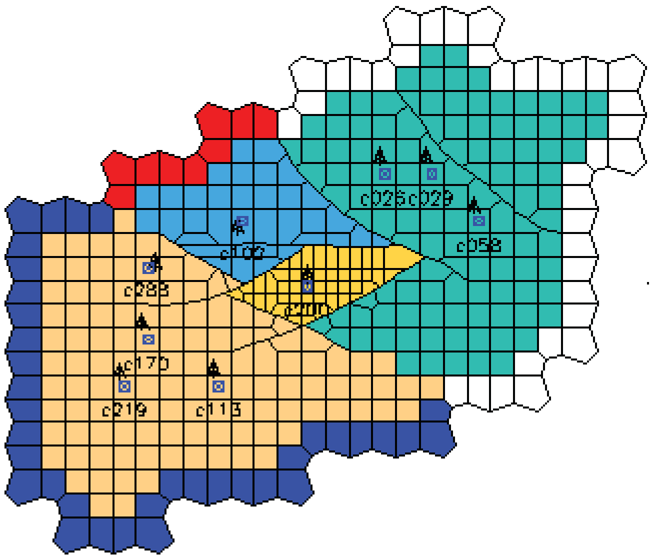

Figure 2.12: Segmented Outer Boundaries and appropriate Target Areas (from *Mittermeir*[44])

In Figure 2.12 the white boundary belongs to the cyan target, the red boundary to the light blue target area and the dark blue boundary belongs to the light brown target area. The center (displayed in orange) area is separated by sealing faults from the rest of the reservoir.

2.4.3.4 Average Boundary Pressure

For most of the applications the average pressure of the boundary must be known. It can be calculated as a weighted average of the boundary block pressures:

$$p_r = \frac{\sum_{j=1}^{m} p_j \omega_j}{\sum_{j=1}^{m} \omega_j}, \tag{2.6}$$

where

j	index number of the boundary blocks $j = 1,..., m$
w_j	weighting factor for the boundary block j
p_j	pressure of the boundary block j
p_r	average pressure of the boundary

Weighting factor w_j can be either the transmissibility to the connected region or the pore volume of the boundary blocks.

2.4.3.5 Distribution of a Given Rate between the Outer Boundary Blocks

Except for the case of a constant pressure boundary, the total water rate through the boundary q_{wn} is determined, which must be distributed among the boundary blocks. The goal is that the individual block pressures converge to the average boundary pressure p_r. Therefore the overall rate will be distributed based on a kind of injectivity index:

$$J_i = \tau_{ij}(p_r - p_j) \quad \text{if } p_r - p_j > 0, \quad \text{else } J_i = 0 \tag{2.7}$$

where j is a non boundary neighbor of the boundary block i and TR_{ij} is the transmissibility for the block pair i and j. If the block i has more than one neighbor, than the injectivity indices will be summed up. If a block j is neighbor to more than one boundary block than the injectivity index has to be reduced accordingly.

Let q_{wn} be the overall boundary rate during a time step Dt_n, then the rate injected into the boundary block i is:

$$q_{wi,n} = \frac{J_i}{\sum_i J_i} \cdot q_{wn} \tag{2.8}$$

2.5 Target Pressure Method

2.5.1 Previous Works

The first step in every History Matching is to determine the objective functions. They are, among others, the well bottom hole pressures, water cuts, GOR etc., but the primary objective must be to match the average reservoir pressure and the pressure for given volume regions. If these pressures do not fit to the measured ones, then there is no chance to achieve a well by well match with the used reservoir model. For a volume region the average pressure is usually given as a pore volume weighted average or as a hydrocarbon weighted average which will be calculated from the regular pressure surveys.

The region pressures depend on the production and on the water influx from the aquifer. The concept of Artificial Boundaries allows to match the historical average pressures directly, without the usual trial and error procedure. The idea is called **T**arget **P**ressure **M**ethod (TPM). The principle and the corresponding work flow will be explained for the most simple case.

Consider one Productive Area with one Artificial Boundary around it, as shown in Figure 2.11. The target volume region is now the whole grid without the boundary blocks. Note that the blocks of the boundary are one phase water blocks, with constant salinity and that no grid describing an aquifer is present.

For the Target Pressure Method the average pressure and the overall compressibility of the volume region must be calculated at the end of every time step *j*. The average pressure is:

$$p_j^{av} = \frac{\sum_{i=1}^{m} \omega_i \cdot p_i}{\sum_{i=1}^{m} \omega_i}, \tag{2.9}$$

where the weighting factor, w, is the total or the hydrocarbon pore volume of block *i.* In Equation 2.9 p_i is the actual calculated pressure of the blocks and m is the number of blocks. The overall compressibility of a block *i* is

$$C_i = V_{pi} \cdot (c_\phi + S_o c_o + S_g c_g + S_w c_w)_i \,. \tag{2.10}$$

The total compressibility of the volume region is the sum of the block compressibilities:

$$C_t = \sum_{i=1}^{m} C_i . \tag{2.11}$$

In this equations

m	is the number of blocks in the target area
V_{pi}	is the pore volume of block i [m^3]
c_ϕ	is the pore compressibility factor of one single block [bar^{-1}]
S_p	is the phase saturation ($p = o,g,w$) [-]
c_p	phase compressibility factor ($p = o,g,w$) [bar^{-1}]
C_t	total compressibility [m^3/bar]

Let q_{wn} be the overall boundary rate during a time step Dt_n, then the rate injected into the boundary block i is:

$$q_{wi,n} = \frac{J_i}{\sum_i J_i} \cdot q_{wn} . \tag{2.12}$$

The rate must be defined for every time step individually. This procedure includes the following steps:

1. Predict the calculated pressure changes for the following time step, Δt_n, based on the pressure decline rates of the previous two time steps.
2. Determine the difference between the predicted and the target pressure for this time point: Δp.
3. Determine the volume of water which should be added to the target volume region to hit the target pressure. This can be calculated based on the overall compressibility given by Eq. 2.11:

$$W = C_t \Delta p . \tag{2.13}$$

4. The injection rate for the Artificial Boundary during the time step Δt_n is:

$$q_{wn} = W / \Delta t_n , \tag{2.14}$$

which will be distributed among the boundary blocks according to Equation 2.8. The injection rate for the first time step is always zero.

Mittermeir[44] published an example to demonstrate the properties of the TPM. Figure 2.13 shows the pressure propagation of the reservoir and Figure 2.14 shows the attained boundary pressure propagation with the associated water injection rates.

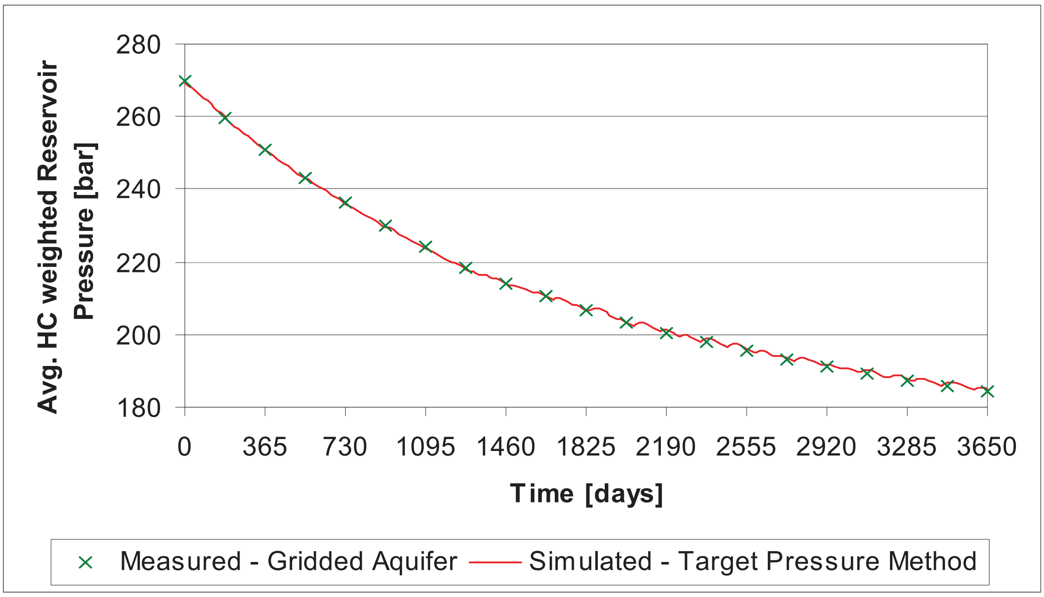

Figure 2.13: Comparison of the result of the TPM calculation with the measured data (from *Mittermeir*[44])

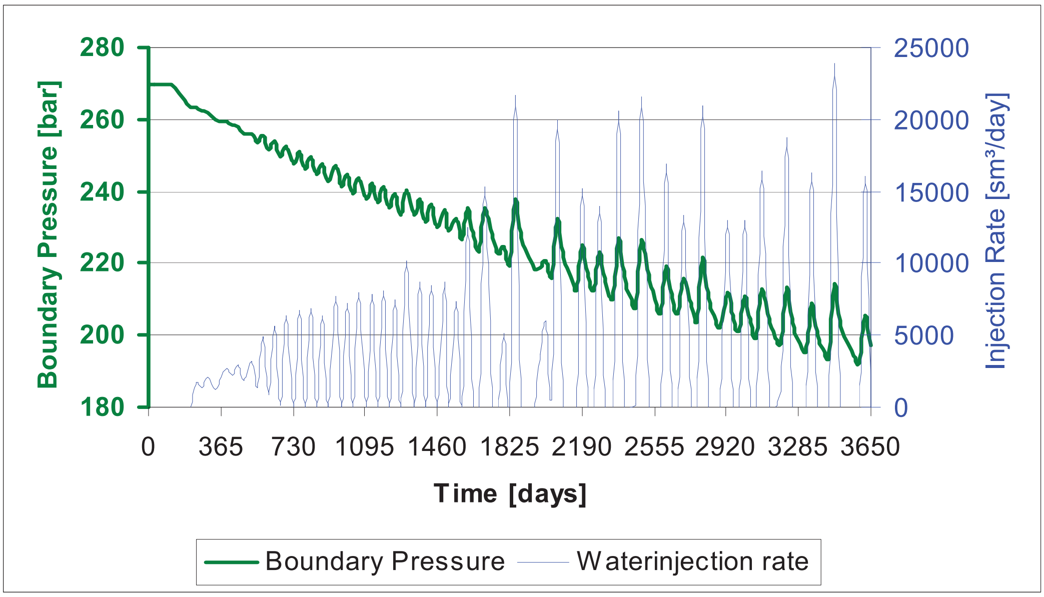

Figure 2.14: Boundary pressure and injected water into the artificial outer boundary (from *Mittermeir*[44])

As can be seen in Figure 2.13 the average reservoir pressure was matched very accurately in one single simulation run. The injection rate that is plotted in Figure 2.14 as a function of time oscillates strongly. This is caused by the explicit implementation of the TPM. This means that the water injection is calculated at the beginning of every time step. As a consequence these oscillations can be found in the boundary pressure and the average pressure of the productive area also, although they are smoothed out in the average pressure of the target area. After *Mittermeir*[45] these oscillations could be reduced by using smaller time steps, but since the reservoir pressure is only influenced very little, these oscillations have no practical importance. The author found, in connection with his field project Lower-GIR[1], that this statement in not generally valid. His suspicion was confirmed by practical application of TPPM to the field Augila and Alborz (private communication Harrer[20])

It should be emphasized that the target pressure method is applicable to reproduce the history but no prediction can be performed in this way. The next step must be to find an aquifer model which provides the necessary water influx over the whole time period based on the calculated boundary pressure of the TPM. Such an aquifer representation can be either an analytical aquifer model or a gridded aquifer. Both will smooth out the water injection rate and the boundary pressure efficiently. The suggested workflow by *Mittermeir*[44] is:

1. Identify the optimal analytical aquifer models and their parameters.
2. Calculate the history with those analytical aquifer models to verify the results of the TPM run.
3. Calculate the extent and permeability of a gridded aquifer.
4. Fine tuning of the History Match using the gridded aquifer model.
5. Perform the prediction runs.

2.5.2 Identification of the Optimal Analytical Aquifer Model

Besides supporting the reservoir from the first moment of the history matching period with the correct water influx, the TPM produces another very important and valuable output. This output is stated in form of the best fitting analytical aquifer parameters. As results of the TPM run, the boundary pressure and the cumulative water inflow, W, are available as a function of time for the whole period of past production. This is analogous to the results of a material balance calculation, and can be used in a similar manner to determine the parameters of the best fitting analytical aquifer model. For this, the following error function should be minimized:

$$E = \sum_{j=1}^{n} \omega_j [W(t_j) - W_e(t_{Dj})]^2 \tag{2.15}$$

where n is the number of time steps, W_e is the result from one of the models described in Section 3.3. $w_j = t_j/t_n$ is a usual weighing factor. This means that the differences in water influx at a later time have more weight as the earlier ones. Different analytical aquifer formulations require a different number of parameters describing it. For the Schilthuis model one (C), for the Fetkovich[19] model two (J_w, W_{ei}), and for the van Everdingen-Hurst[63], Vogt-Wang[64] and Carter-Tracy[10] models three parameters (r_{De}, β and *C*) will be determined. For all models also the standard deviation, *s*, will be calculated, showing which model type is the best one. Using this best fitting aquifer model, the run can be repeated and proven if the historical pressure can be satisfactory reproduced or not. If this is possible, it can be expected that the analytical model is suitable to provide the required water influx for prediction runs. This is especially the case if the aquifer does not manifest complicated or irregular behaviors.

For all analytical aquifer models mentioned above, the parameter pairs or triplets fitting best are determined using a generic algorithm. Detailed description of this procedure is given by *Pichlbauer*[51], *Mittermeir*[44] and in PRS Technical Description[29].

2.5.3 Application of TPM to TPPM

2.5.3.1 Experiences

As already mentioned the Target Pressure and Phase Method is an extension of the Target Pressure Method. Theoretically all three aquifer types could be applied to TPPM. PRS offers all of them, ECLIPSE only Fetkovich[19] and Carter-Tracy[10]. The Vogt-Wang[64] model which is in fact the same as the Hurst-van Everdingen[63] model, is not available in ECLIPSE. The Carter-Tracy model is an approach to the Hurst-Everdingen model with the apparent advantage that it is not necessary to store the boundary pressures for all previous time steps. For this reason the Carter-Tracy model become popular in the early time simulation software (Three-Three, ..., but also ECLIPSE). Numerical experiments showed that the results from PRS and ECLIPSE differ up to 20%, which is not a problem using both simulators independently because the parameters will be tuned during the HM anyway. For TPPM this discrepancy is unfortunate, It deteriorates the compatibility of the two simulators. How the Carter-Tracy model is implemented in ECLIPSE is not known and the code is not accessible for the author. No insufficiency or bug could be identified in PRS and so there is nor reason to doubt its correctness. In this situation the Fetkovich model is the only one usable today for TPPM.

2.5.3.2 Improvements

It can be checked easily, how good the aquifer modeling works. The target pressure run must be repeated with the analytical aquifer model, using the parameters determined automatically by PRS. The run can be repeated with ECLIPSE too, checking the compatibility also. Simple small (academic) models gave mostly satisfactory results. Experience with the large full field cases as Upper-Gir, Augila and Amal (mentiond in Section 2.5.3.1) showed that some improvement would be advantageous. Two possible discrepances between the ptarget and fetkov approach would be presumed and eliminated in PRS:

1. Using ptarget option the water influx (injection in boundary) is calculated for a predicted average region pressure after a given time interval. The fetkov option calculates the water influx based on the actual average boundary pressure. The author introduced an alternative option, govered by keyword, considering the average region pressure instead of the average boundary pressure.
2. ptarget handle the boundary block pressures impicit the fetkov expicit. The author changed the second one to an implicit formulation.

The following example shows that this heuristic approach could be regarded as a successful step. A deeper investigation and scientific prove of this question is beyond the objectives of this work.

2.5.3.3 *Fetkov* Test Model

While conducting this thesis work it was discovered that the two simulation packages in use, PRS and ECLIPSE, give different results when an analytical aquifer model of Fetkovich type was used. Depending on the complexity - in terms of phases (oil, water, free gas), number of blocks, extend of the boundary, etc. - the differences could be regarded either as minor or severe. Further it was discovered that tuning the parameters of the Fetkovich model (maximum enroachable water and aquifer productivity index) would lead to satisfactory results. No general rules for tuning could be determined. Consequently this tedious work had to be done in trial and error process for every model setup individually. Naturally this is not a satisfactory situation.

In order to be able to investigate the differences between the PRS and ECLIPSE Fetkovich aquifer model implementation, it was decided to create a simple model. One of the objectives during model design was that this model could be also calculated manually by a simple material balance calculation. Therefore it was decided to create a one dimensional (1D), horizontal, one phase (water) model with one water producing well and a single boundary block. A cross section of this model can be found in Figure 2.15.

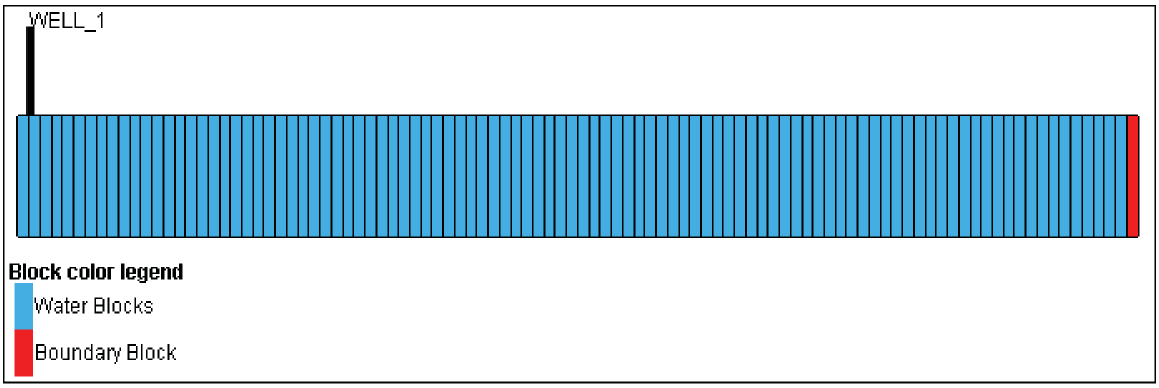

Figure 2.15: : Cross-section view of Fetkov Test Model showing well position and boundary location (exaggeration = 50).

The entire model consists of 100 blocks. Each of these blocks is, equally shaped with equal dimensions and properties (e.g. porosity, permeability, etc.). Due to the horizontal character of the model all blocks have the same pressure after initialization.

The model was operated for a period of 10 years. During the first 5 years the water producer was operated at a constant water production rate of 50m³/day. During this period the average pressure of the model decreased leading to a water encroachment from the analytical aquifer. After this withdraw period the water producer was shut in and the model was calculated for some other 5 years. Due to the pressure gradient in the model (shown in Figure 2.16) created by the water withdrawal, water encroachment from the analytical aquifer continued until the average pressure of the model and the aquifer pressure became equal. This is documented e.g. in Figure 2.20.

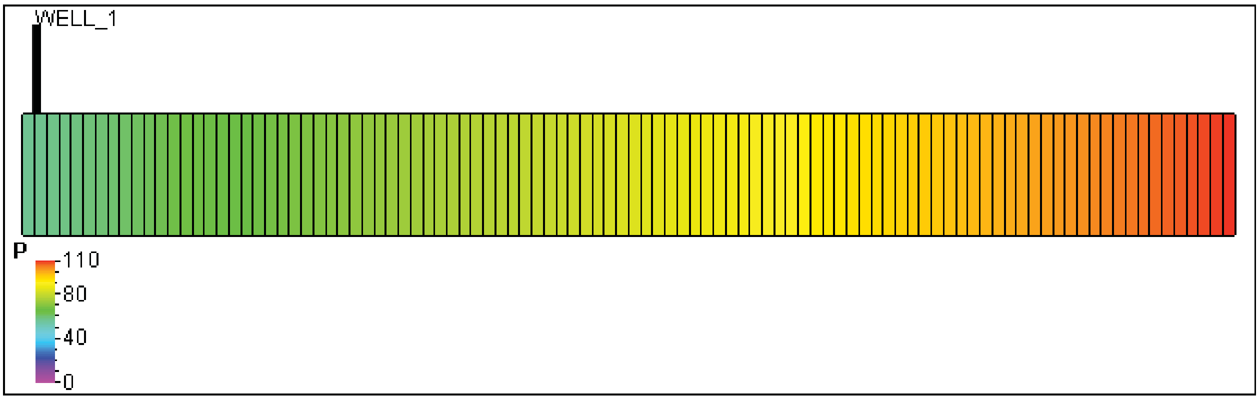

Figure 2.16: : Cross-section view of Fetkov Test Model showing pressure gradient between water producer and analytical aquifer at 1988/01/01 (exaggeration = 50).

The above mentioned setup was run with PRS and ECL with a time step length of 31 days. The entire input was the same. The input parameters of the aquifer model were converted from ECLIPSE (which is regarded as the reference for this test model) to PRS as shown below.

```
# B O U N D A R Y - D E F I N I T I O N S
#----------------------------------------
#ECL input is the following:
#---------------------------
# Datum depth                    : 1000      [m]
# Initial aquifer pressure at datum : 110       [bar]
# Inital water volume in the aquifer: 4E+10      [sm3]
# Total (rock+wat)compressibility   : 10.35e-005 [1/bar]
# Aquifer productivity index        : 100       [sm3/(bar.day)]
# -------------------------------------------------------------
#PRS input is the following including detailed conversion steps.
#-------------------------------------------------------------
# Wei = ct*W*pi
# Wei = 10.35e-005 [1/bar] * 4E+10 [sm3] * 110 [bar]
# Wei = 4.554000E+08 [sm3]
# BOUNDARY Bound1 Fetkov AQUIWEI 4.554000E+08 AQUIJW 100.0
```

Figure 2.17 shows a comparison of average reservoir pressure calculated by PRS (shown in green) and ECLIPSE (shown in blue). Both simulators were operated at a time step length of 31 days. The ECLIPSE result clearly shows the two periods (water withdrawal and pressure buildup) and a smooth pressure propagation. Contrary the PRS results shows a very unsteady, zig-zag like pressure propagation. The PRS run was repeated with a time step length of 1 day. For this small timestep length which is not applicable for full field runs also PRS calculated a smooth pressure propagation. This is shown in Figure 2.18. Figure 2.19 displays the cumulative water influx across the boundary/from the analytical aquifer into the model area. This plot clearly shows an uneven water encroachment for the PRS run with 31 days time step length and an even water encroachment for the PRS run with 1 day time step length and the ECLIPSE run with 31 days time step length. It should be noted that the cumulative influx and the final pressure are equal for all three investigated scenarios.

Combining the findings of Figure 2.17, Figure 2.18 and Figure 2.19 following conclusion can be drawn. The uneven water influx calculated by PRS based on a time step length of 31 days leads to high pressure (average model and BHP pressure of the water producer) fluctuations. For such a time step length PRS overestimates the required water influx rate, leading to a pressure increase in the model, which hamper further water encroachment until the pressure has declined again.

This observation can be easily explained by the nature of how the analytical aquifer models are implemented in PRS. PRS treats the analytical aquifers explicitly. This means that at the current time step the water influx for the next time step is already estimated. The longer the chosen time step length, the more likely this estimation deviates from the actually required water influx rate.

In order to resolve this problem, implementation of the PRS Fetkovich analytical aquifer was improved in a way that the calculation is treated now implicitly. The success of this improvement is shown in Figure 2.20.

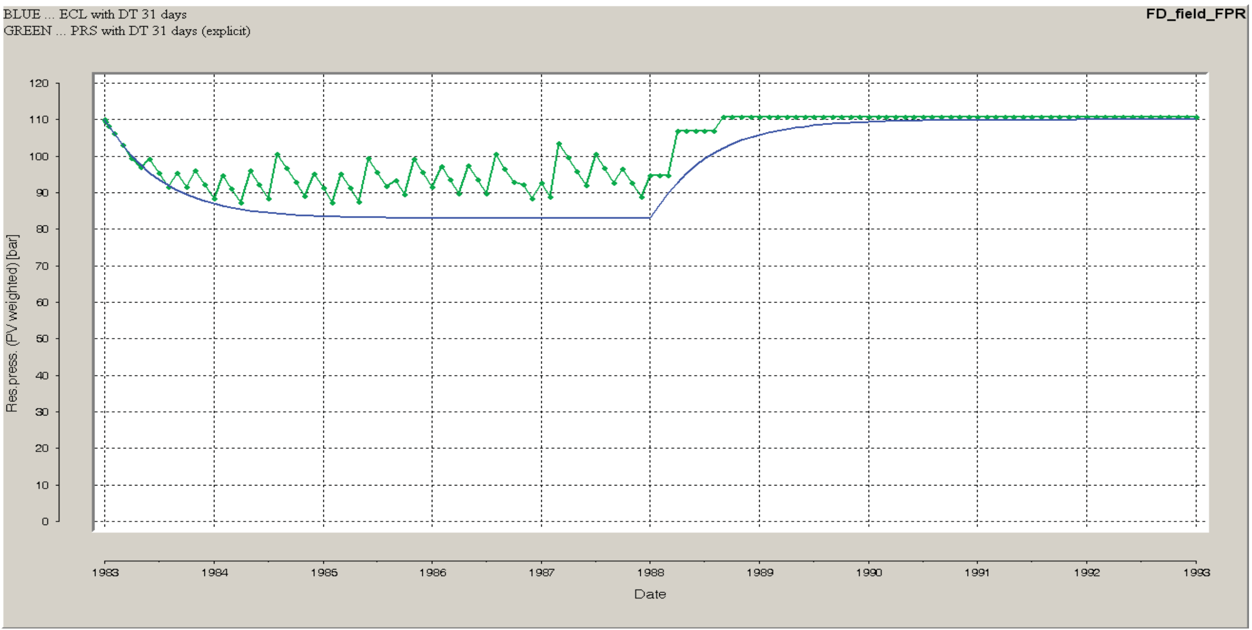

Figure 2.17: Comparison of average reservoir pressure calculated with ECLIPSE and PRS (before improvement) at a time step length of DT = 31 days.

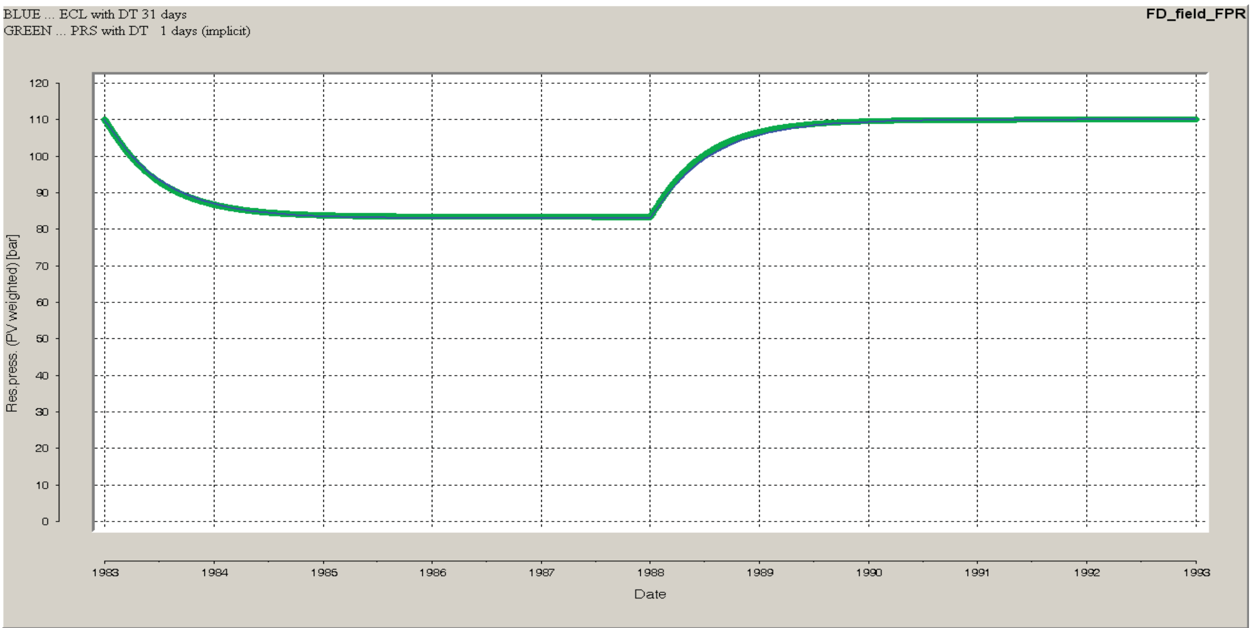

Figure 2.18: Comparison of average reservoir pressure calculated with ECLIPSE and PRS (before improvement) at a time step length of DT = 1 days.

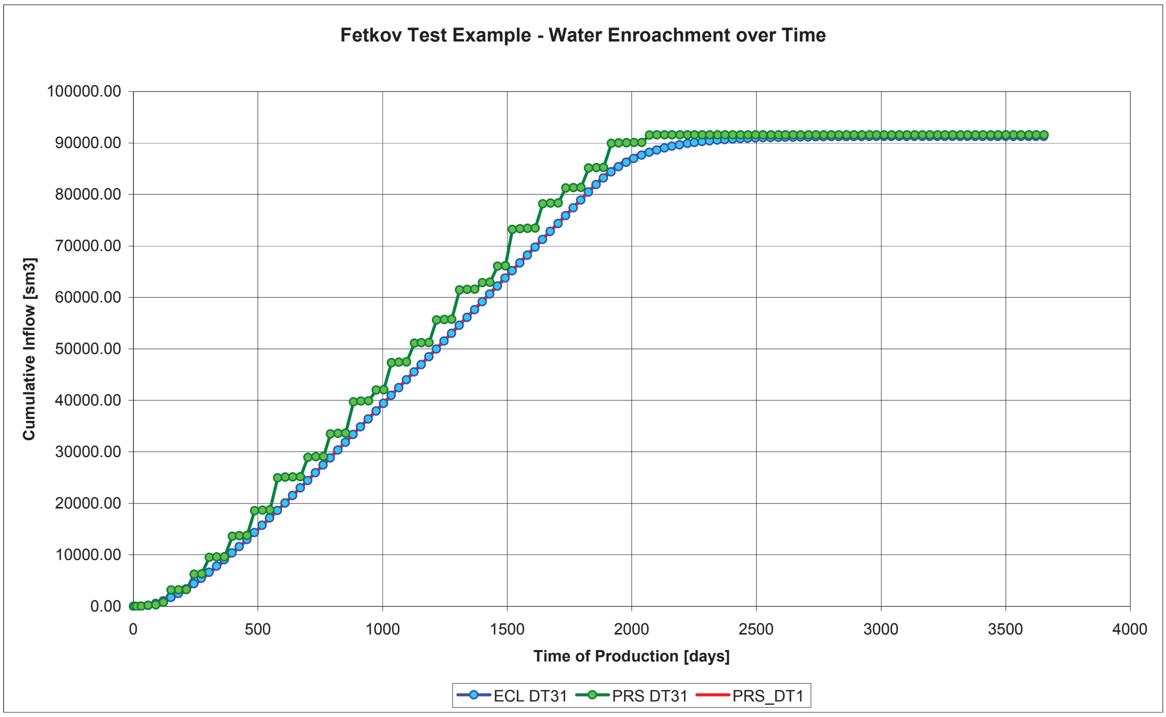

Figure 2.19: Comparison of water encroachment as a function of time for Fetkov Test model before improvement of PRS.

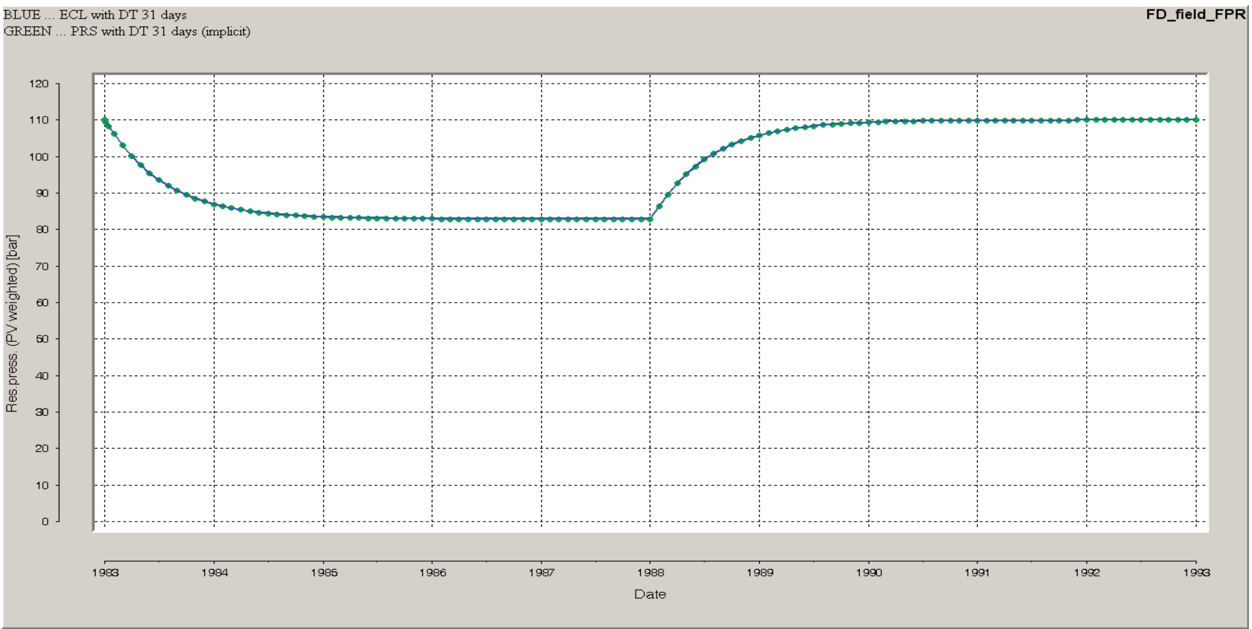

Figure 2.20: Comparison of average reservoir pressure calculated with ECLIPSE and PRS (after improvement) at a time step length of DT = 31 days.

Chapter 3

Target Pressure and Phase Method

3.1 Definition of TPPM

In conventional history matching (HM) process the outputs of the dynamic model were the pressures and the production rates. They are compared and if they more or less fit to the historical data then the matching was successful. This process is described and displayed on the Figure 2.3 and Figure 2.4. *Pichelbauer*, *Mittermeir* and *Heinemann*[51,42,44] introduced the Target Pressure Method (TPM) which made the HM process more efficient. The area pressures were defined as input and the boundaries provide the water inflow (sometimes outflow) following closely the pressures as shown in Figure 3.1. At the end of every run the optimal analytical aquifers were identify and their parameters determined. The weekness of the method is that the wells are not able to produce the assigned oil or gas rates with the meassured GOR and water cut or the wells were constraint by minimum bottom hole pressure before the end of the HM. To decide if a given geological realisation is correct or not still needed a time consuming inner iteration as displayed in Figure 2.4.

The author suggested to extend the concept. The basic idea was to define beside the area pressures (Figure 3.1) also the oil, water and gas production rates (Figure 3.2) as targets and give them as input, also extend the the Target pressure Method (TPM) to a Target Pressure and Phase Method (TPPM). Between the conventional approach in Figure 2.5 and the TPPM in Figure 3.3 is the difference that the arrows have the opposite orientation. While the desired production by the model wells are normally not possible, the wells are authorised searching the required phases (oil, gas and water) within a greater volume; in the worst case within the entire pressure region. If all wells find its produced phase volumes all the time within limited spots, which can be regarding as the own drainage area, then the geological model is globally right. If not, the given realisation must be rejected. The screening of the geological realisation becomes fast and efficient because the inner iteration loop becomes obsolate as shown in Figure 3.4. Note that TPPM can and should be used directly on the static models without any simplification or upscaling.

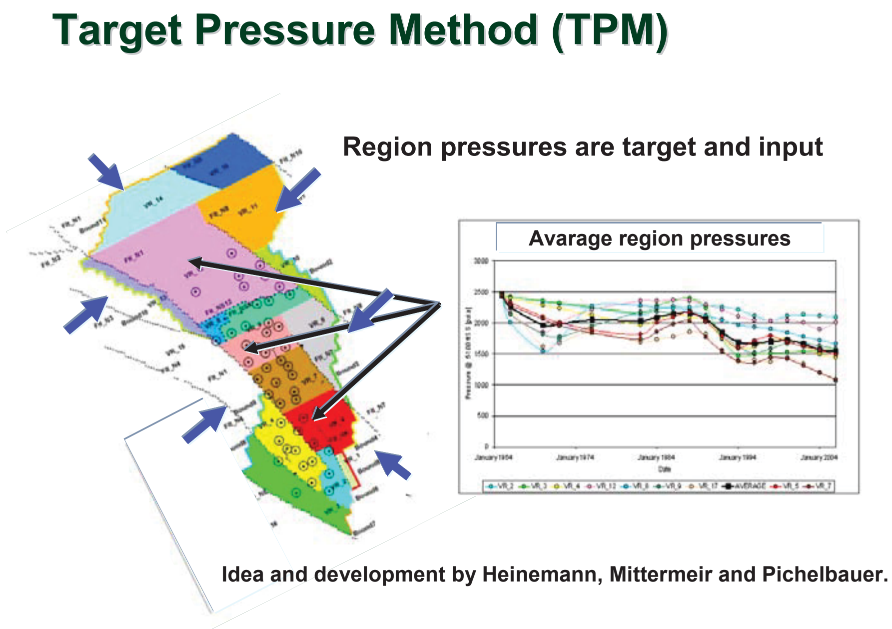

Figure 3.1: Principal of the Target Pressure Method. Idea and development by *Pichelbauer*, *Mittermeir* and *Heinemann*[51,42,44]

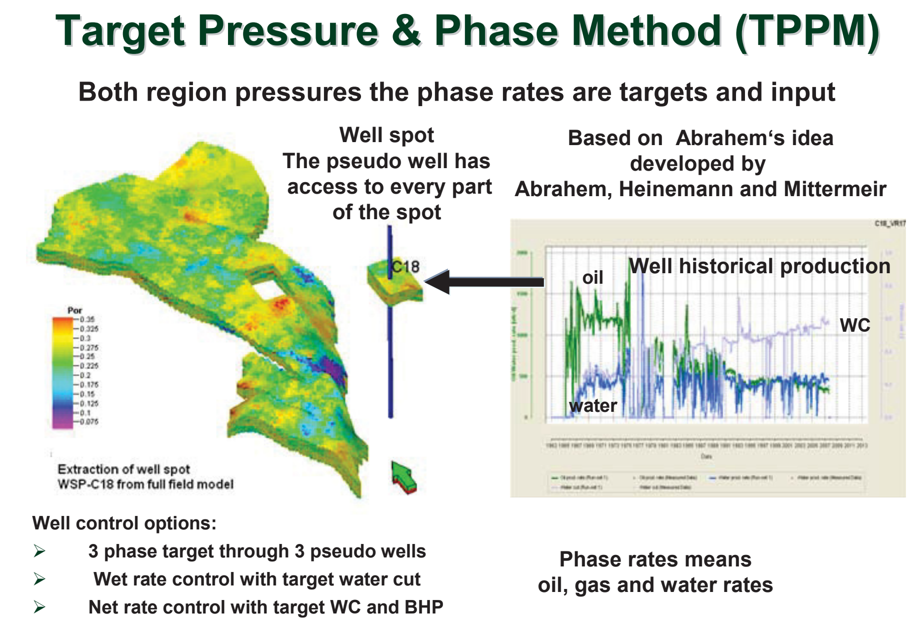

Figure 3.2: Concept of Target Pressure and Phase Method. TPPM assignes the phase production rates to well spots and not to the wells. Idea from Abrahem.

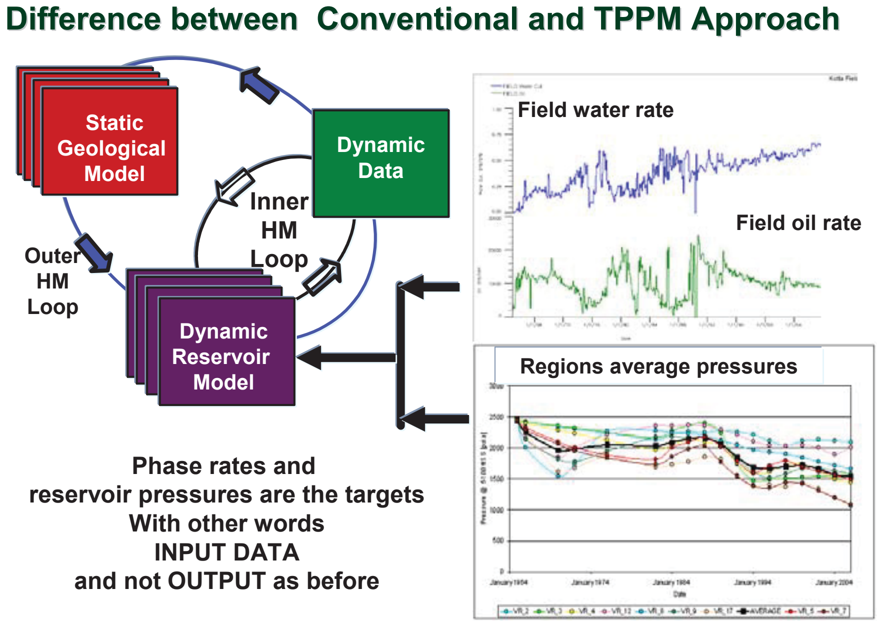

Figure 3.3: Difference between the conventional (see Fig.2.5)and TPPM history matching approach. The Target Pressure Method (TPM) is part of TPPM.

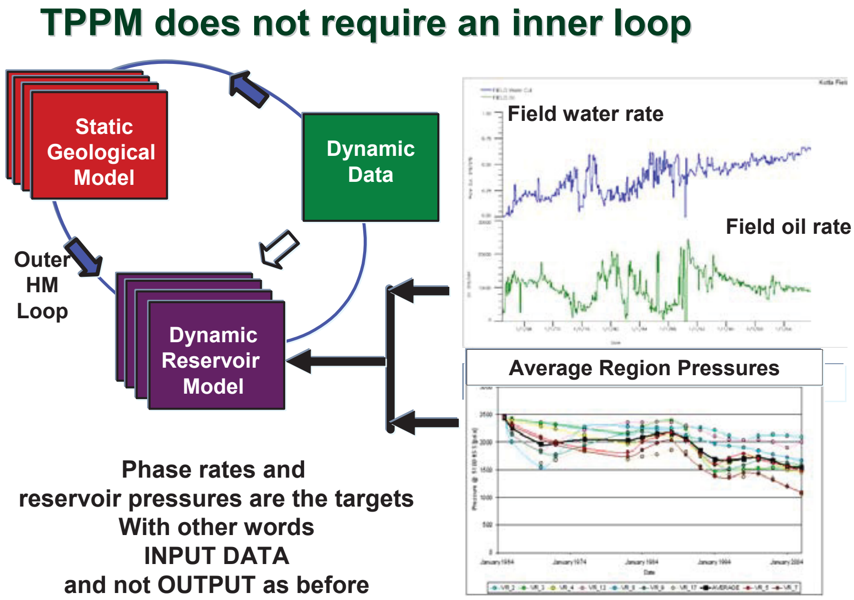

Figure 3.4: Target Pressure and Phase Method dicectly screens the geological realisations.

3.2 Elements of TPPM

This chapter presents the reservoir modeling workflow, based on the concept of **TPPM**. The **TPPM** is a well defined new method and an option in **PRS**. TPPM is not available in other simulators today, also not in ECLIPSE. Nevertheless ECLIPSE is an important element (tool) in the new workflow.

TPPM takes advantage of a large number of well known and widely used options and methods. It will be assumed that the reader is familiar with them. Methods available in most of the commercial simulation software, especially in ECLIPSE, will not be explained. It is also assumed that the reader is an experienced user of reservoir simulators, having an overview about the difficulties and pitfalls of any History Matching (HM) work. Nevertheless the previous chapter gives some background information about the author's view and understanding regarding selected topics. They should minimize the risk of mutual misinterpretations. These questions were the following: (1) difference between Modeling versus Simulation; (2) what is History Matching; (3) Automatic and computer assisted HM; (4) Aquifer modeling; (5) Target Pressure Method (TPM).

TPPM operates on two different objects, the aquifers and the wells:

1. The aquifers are handled in two ways: the aquifer boundaries supply water into the model to follow the area target pressures (ptarget) or a given analytical aquifer model supplies water according to the actual (i.e.: boundary, regions) pressures (fetkov). Detailed descriptions are given in Section 5.3.

2. The wells are sources connected somehow to the reservoir and operated under different conditions. A well is identified by name and characterized with a series of attributes and keywords:

matching: The well is object of the TPPM process.
netrat: The net production rate or injection rate is specified for an individual well.
wetrat: The gross production rate (oil + water) is specified for an individual well. This possibility may be used for oil wells, but is not feasible for gas wells.
ph3rat: The rates of all three phases under surface conditions are specified for a well in the production statistics file.
WPIMULT: Maximum value of the productivity index multiplier.
STRETCH: Maximum number of possible pseudo perforations which will be opened if necessary.
EXTEND: Number of pseudo perforations to be open definitively.

All objects can be handled individually: one boundary operates in ptarget and the other with fetkovich analytical aquifer, some wells operate in matching mode, the reminders conventional.

3.3 The TPPM Work Flow

1. Setting up an ECLIPSE Model

The starting point of a TPPM procedure is the re-gridded and upscaled dynamic reservoir model, equipped with everything necessary to start a simulation run. The preferred set up is an ECLIPSE input deck. The completeness and consistency should be checked by initializing the model and running it, formally using ECLIPSE 100 simulation software. The adverb “formally” means that the input should be checked for syntax and physical meaning but not for project related correctness.

2. First PRS Run

Step 1. will be repeated using PRS. Besides, a short command file with the extension <name>.tdd no supplementary inputs are necessary. In the first step PRS reads the SCHEDULE file and transfers it into a form, which can be read more easily by PRS (but also by everybody else). If the user intends to modify or extend the data for any reason, then this should be done in ECLIPSE files already. Step 1 should be repeated after all input has been updated. The consistency between the two software should be kept at all time during the project. Note that this is a conventional and not a TPPM run.

3. Assessing Pressure Regions

The grid model (the reservoir model) should be partitioned in pressure regions for which the average pressure development will be assessed for the entire history. They are the target pressures (ptarget) for the matching. The pressure regions are normally defined as volume regions. At the same time also boundaries should be defined to which analytical (or numerical in ECLIPSE) can be allocated. ECLIPSE allows to choose any set of existing blocks within the grid; they must neither be on the outer side of the active area, nor on a continuos surface. PRS is more restrict in this respect so this should be geometrically and hydrodynamically really a boundary. This boundary should be defined equally in ECLIPSE.

To every pressure region one and only one boundary can be assigned in PRS. This coupling must not be outright. Not all regions must be connected to a boundary and a boundary can be assigned to a region without having direct (geometric) connection to this.

4. Setting Pseudo Perforations

Supplementary perforations (connections) should be given to wells, called pseudo perforations. As first choice the blocks along the well trajectories should be considered. In case of vertical wells all layers above and below the real perforations should be declared as possible connections. In case of horizontal wells also blocks outside of the trajectory lying in the vertical and/or in the horizontal plain can be considered. Generally speaking the well will be regarded as a pseudo multilateral well, having access to its entire drained reservoir volume. All these pseudo perforations should be introduced (for data management reasons) into the simulation software, at the model initialization and then be closed.

5. Operating PRS with Pseudo Wells

A TPPM run with PRS differs from the conventional run in Step 2 only by adding the attributes tppm proceed to the command file. The first runs should be carried out with the aquifer option ptarget and matching ph3rat option for the wells. The target phase rates will be distributed individually among the perforations based on the Equation 5.4. Consequently two (or three) bottom hole pressure (BHP) will be obtained from Equation 5.5, different for oil, water (and gas). The result is naturally not physical, but this is also not required at this stage. Important is only that all wells produce the reported rates over the entire history. If this is possible than there is enough mobile oil, water and gas at the real perforations all the time and the model is globally right. If this is not the case, then the pseudo perforations can be opened one after one. If the well can not operated even in such a way, then the available amount of oil, water and gas globally or locally is insufficient. To be able to complete the actual run, the problematic wells will be switched to wetrat control. Also the low permeability can constrain the wells by minimum bottom hole pressure. Productivity index multipliers will be applied automatically to keep the model wells in operation. Note that as consequence of the ptarget option the average reservoir (i.e.: pressure or volume region) pressure is always correct.

6. Revision of the Static Model

Now the wells are ordered in two groups, the good ones fit to the expectations in Step 5 and the bad ones do not. In the second group are the wells which were switched from ph3rat to wetrat and those which were constraint by minimum bottom hole pressure. The locations of the bad wells give clear indication about the problems in the geological model.

In case of multiple realization a ranking is possible already at this state. Note that all of the models were run over the entire history and the development of the reservoir pressure is practically identical in all. The user can sort out the unrealistic (contradicting) realizations coming to an considerable narrower model spectrum.

PRS writes out a diagnostic file with all comments given during the run ordered by wells and date. Supplementary the result(s) can be loaded in PETREL, displaying the reservoir status, by highlighting the bad wells and showing the phase movements over the production time. The whole team (reservoir engineer, geologist, geophysicist, production engineer) should sit together watching the movie and finding out the reasons for failure. It should be discussed and agreed which supplementary investigations are necessary and how the static model could be improved. In TPPM it is forbidden to tune the dynamic model at this level of the work.

Steps 5. and 6. will be repeated until there are no more bad wells. During this cycle increasing emphasis should be put on two details:

- pseudo perforation which would be opened
- the differences in the phase bottom hole pressures (see Section 5.2.1.).

7. The Globally Matched Model

At this point the dynamic model is globally matched. All well spots (drainage areas) of the model produce the historical oil, water and gas rates and the reservoir (regions) pressures are equal with the target pressures over the entire production time. Therefore all terms necessary to determine the optimal analytical aquifer parameters are given.

An advantage of this model compared to any conventional approaches is, that one can have more confidence in the distribution of the mobile phases (oil, water). A supplementary advantage is that the global TPPM matched model updates itself automatically. The HM can be extended and the prediction can be updated month by month.

8. The Spot by Spot Match

The well control should be switched to wetrat. This can be done generally or partly, concentrating on one area or a group of wells only. To keep the other wells at ph3rat has the advantage, that the actually focused wells cannot be influenced by discrepancy in partitioning of the fluid in oil and water (as it can occur with wetrat).

What the TPPM approach can do at this stage is easily explained: The run informs the user which well construction (location and PI's of perforations) could produce the historical rates with the measured BHP at the offered reservoir structure and parameters within the individual spots (drainage areas). TPPM opens and closes pseudo perforations and assigns PI multipliers to the individual perforations to match the targets. The solution is naturally not unique. Therefore PRS offers options as stretch, extend, average, forced, WPIMULT, WPIMULTP with which the user can influence and constrain the automatic matching. In this way the TPPM provides pseudo wells telling the user "*if your reservoir spot looks like this, and this is your grid model then I would need such a well producing as targeted.*" If the pseudo well differs considerably from the real well, than the reservoir geology must be updated. The quality measure of the reservoir description are the artefacts in the tuned pseudo wells. The objective of the fine re-parametrization of the reservoir model is to eliminate or at least to reduce the number (extension) of the pseudo perforations. In TPPM it is still forbidden to tune the dynamic model at this level of the project.

9. Implementation of Predictive Capabilities

The TPPM globally matched model has also higher predictive capability. The existing wells can be operated with estimated rates and WC (using decline curves) and new well locations can be checked similar to a conventional model. In many cases such a globally matched model is sufficient for operative decisions.

The main object of any HM is to end up with a dynamic model possessing the highest possible predictive capability. For that it is a fundamental requirement that all modelled wells should reproduce the cumulative oil and water production for the entire production period and the slope of the curves in the last years should fit to the observations (see Section 3.3.). If this is the case than one can be confident in two respects:

- The correct amounts of oil and water are located at every well drainage area all the time. Therefore it can be assumed that the distribution of the phases in the reservoir is modelled correctly and the place of the remaining oil is determined credibly.

- The model reproduces today's well productivity. Therefore the model can be used to predict the well and field performances.

The TPPM option matching ph3rat satisfies this requirement automatically but a forecast is only possible if the user can define the conditions for future oil, water (and gas) rates with sufficient certainty. Note that a physically right description of the near well flow is not available at this stage (could be achieved after the well by well match, if anyway). Practically two approaches are possible:

The first possibility is to extrapolate the observed (historical) oil rate, WC and GOR directly by establishing decline/incline rates as functions of time, average reservoir pressure, cumulative production, etc.. This does not sounds very scientific but most of the reservoir engineers are more confident with this than with an analytical approach. Note that such a forecast is the bases for asset evaluation and reserves estimation in most of the cases.

The second possibility is to use the information about reservoir-well connection offered by the pseudo well with matching wetrat option. Note that in this case the "perfect" well match is not assured automatically like with ph3rat and requires some efforts from the user to achieve a satisfactory match. Possible improvement of the geological parameters will be conveyed to the prediction directly but the pseudo perforations and the PI multiplier need to consolidate. They can and will be different in every time step during the HM but must be made permanent for the forecast.

10. Consolidation of the Pseudo Wells

The reasons why the pseudo perforations and the perforation transmissibility multipliers for a well change over time are manifold: the reservoir parameters, errors in production data, insufficient description of the physics (i.e.: coning), the grid resolution, etc. It must also be considered that the inflow performance of the real well changes over time in most of the cases. It should be accepted that the HM seldomly can be successful with a single setup of the pseudo wells. This question is discussed in Chapter 5 in more details.

Besides the stretch option, PRS offers the option extend with which the number of pseudo perforations can be fixed. Using extend for the last years of the history assures that no further changes occur in this respect, what is advantageous for the prediction. The best is naturally if no pseudo perforations are necessary (so the input is extend 0 0).

The tppm proceed run writes a file about the perforation adjustment for every well containing the actual and the pseudo perforations and the perforation multipliers as a function of time. A supplementary option in PRS is evaluate which balances out the pseudo perforations and calculates average multipliers over longer time intervals. The balancing out means that the outliers in pseudo perforations will be eliminated and the multiplier averaged. The keyword SMOOTH governs this smoothing with the integer parameters -1 to 4. No averaging will be done by SMOOTH -1; with 0 all pseudo perforation set ups will be kept but the multiplier will be averaged for time intervals with identical perforation patterns. By SMOOTH 1..4 the smoothing becomes deeper and deeper. Note that SMOOTH is a time dependent parameter.

PRS writes the **C**onsolidated **W**ell **A**djustment data in the **CWA** file containing date sorting of all wells, using the PERFSPEC identifier (keyword) for perforation specification.

Following a tppm proceed run, the step evaluate can be repeated as one’s liking.

11. Verification run

The TPPM result can be checked by performing a conventional PRS run (by discarding the attribute tppm) and using CWA as include file. With SMOOTH -1 the two runs will be nearby identical. The reason for small differences is explained in Chapter 6. This step should be done always before the prediction is set up, checking if the model was not corrupted by the process evaluate.

12. Transfer to ECLIPSE

The option tddm shedule has the function to update the original ECLIPSE SCHEDULE file with the CWA data. The original file will be read and the TPPM operations will be introduced with the ECLIPSE keywords WELOPEN and WPMULT. Afterwords the example can be run as usual.

3.4 Well by Well Matching

The on Spot-By-Spot level history matched reservoir model is satisfactory for most of the reservoir management problems but certainly not for optimizing well constructions (completion, multilaterals) and operations (smart wells). The engineer has the possibility to improve the reservoir model by near well modifications in the same way as he would do it in a conventional workflow. This must be done with care, because a more reliable modeling of near well phenomena needs higher grid resolution and improved discretization approaches too. The necessary and suitable methods are well known from the literature: local grid refinement, sublayering, windowing technique, unstructured PEBI grid, streamline technique, etc. Most of these methods are available in PRS. Unfortunately they are not or only in limited amount available in ECLIPSE and in other commercial simulators. The theoretical backgrounds and the questions of practical application are presented in detail in PhD theses of *M.Mlacnik*[46], *G.F.Heineman*[23], *S.Brockhauser*[9], *G.Mittermeir*[44,].

Chapter 4

The Field Case

4.1 Field Data and Project Objectives

CON55 is an oil field situated in the central part of the #S basin. The oil bearing layer is the #G formation of Upper Cretaceous age. The predominant lithology is limestone that has partly been dolomitized. Sedimentation occurred in a reefal and near reefal environment, which was influenced by tectonic and eustatic forces.

The field was discovered in July 1963. Since then, 58 vertical wells and 3 horizontal wells have been drilled into the #G formation. As of March 2006, cumulative oil production was ### MMSTB, with the current daily production being ## MSTB. The reservoir drive mechanism is believed to be a strong water drive that is supporting the pressure from the east and from the north.

Several full field studies have been performed to characterize the CON55 field. The last study was completed in 1998. Since then, new 3D seismic surveys have been acquired and six additional wells have been drilled. The HOL study[41] incorporates the new data to improve the understanding of the reservoir and to propose optimized field development strategies. The main objectives of the study have been defined by AGOCO:

- Provide a sound geological and reservoir engineering model;
- Evaluate various development strategies, including possible water injection schemes, to boost reservoir pressure, mitigate the high rates of water production and enhance oil production.

The central and decisive step to achive these goals is to create a dynamic reservoir model and use it for modeling and simulation. No reservoir model is good or wrong, but more or less suitable to achieve the study goals. The specific objectives of the modeling and history matching are the followings:

- Validate the geomodel with respect to dynamic flow behavior and to gain additional information to be incorporated into the geomodel.

- Create a dynamic model which can credibly predict and optimize future developments.

The first objective has more or less a qualitative nature. The geomodel should and will be constructed by considering all knowledge gathered over 45 years of production from CON55 Field. The second requirement is strictly quantitative. The model should manifest strong predictive capability for both.

- the amount and location of the reminder movable oil, as target of future development,
- the future production of existing and new wells.

The credibility of the model will be based on the description of the past i.e.: on the quality of the history match: All single model wells must be able to produce the quantity of oil and water as reported in the history. Both the oil and water production rates (i.e.: water cut) in the last year should be close to the measured. The simulator should honor the observed tendencies. In this case the model can predict the future performance.

4.2 Summary of the Geological Model

This section is a summary from the CON55 Integrated Study. The study was conducted by a team build by experts of AGOCO and HOL. The study was completed in November 2009 and the result was presented in 7 Volumes. The author was not member of this team, but got limited permission from AGOCO to use some data for his work, performed independently from the study. This Section is based on the data and results presented in Volume 4[13].

4.2.1 Structure of the reservoir

The upper #G Formation, sometimes referred to as the #K Member, consists of porous limestones of variable lithologies that have been interpreted as a reef complex, although it is probably more correctly referred to as a bioherm. Upward growth of sessile organisms during periods of episodic subsidence alternated with emergence and subaerial erosion of the central core and deposition of outward-dipping layers of calcirudite. The CON55 reservoir occurs in the massive biohermal core and in the flanking calcirude beds. The massive carbonate interval is characterized by high porosity whereas the flanking beds exhibit pronounced variations in porosity and typically are coarser and more porous upwards.

The reservoir of the CON55 Field has the form of an elongated horst block, which is dipping towards the north and bounded to the east, west and south by major extensional faults. Unfortunately seismic reflections along these structural ramps are continuous and do not provide clear indications of faulting. It is also possible to interpret faults forming more or less isolated fault blocks or define structural blocks that are connected over steeply dipping structural ramps. Probably the reality is a combination of the two. The structural ramps may in reality be traversed by series of minor, NE trending en echelon faults which accommodate the structural deformation in these areas[14].

The production history showed indications for both concepts. Most of the major faults were proved as sealing but the high productivity indices of wells along this faults speak for en echelon like faulted structure.

A 3-D view of the structural configuration of the CON55 Field is shown in Figure 4.1. The fault pattern is given in Figure 4.2 together with the well locations and the pressure (or volume) regions. The boundaries between the regions VR_9 -VR_12 and VR_8 and VR_9 were interpreted as faults (NS12 and NS8) in earlier geological models.

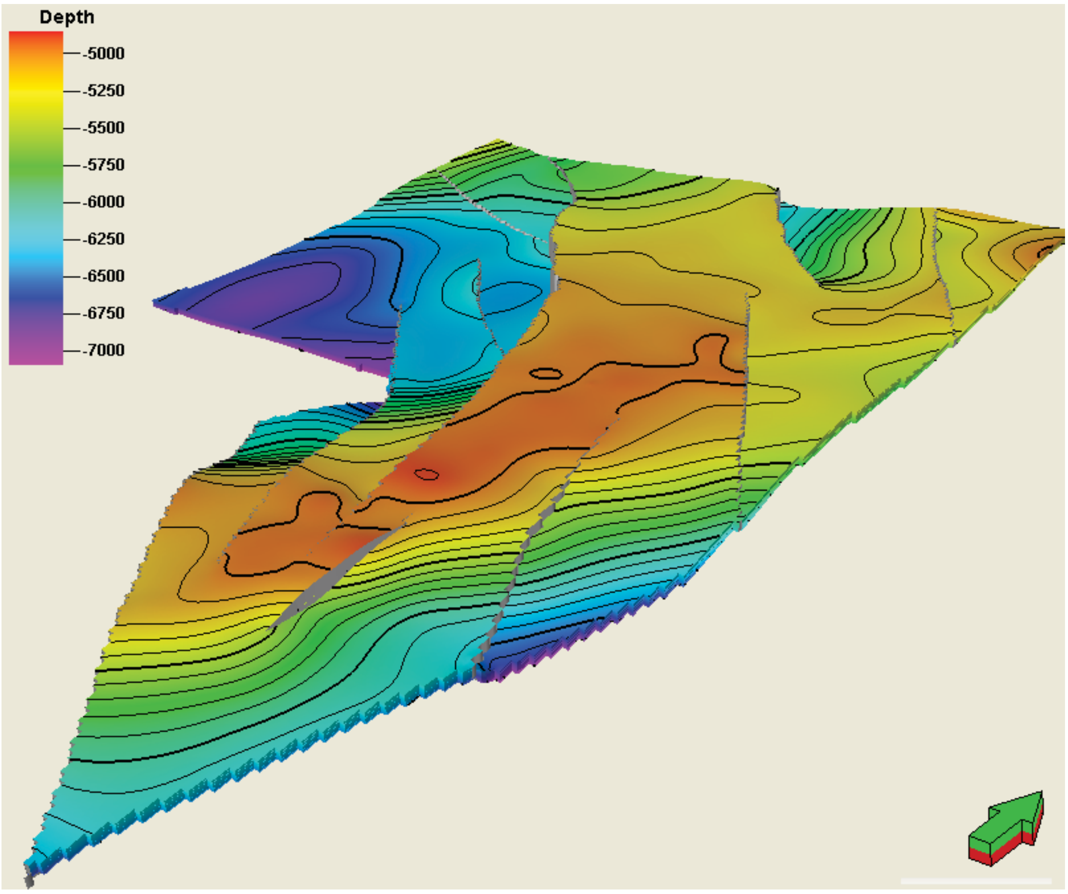

Figure 4.1: 3-D view of the structural configuration interpreted for the northern area of the CON55 Field (after Davis and Egger[13]).

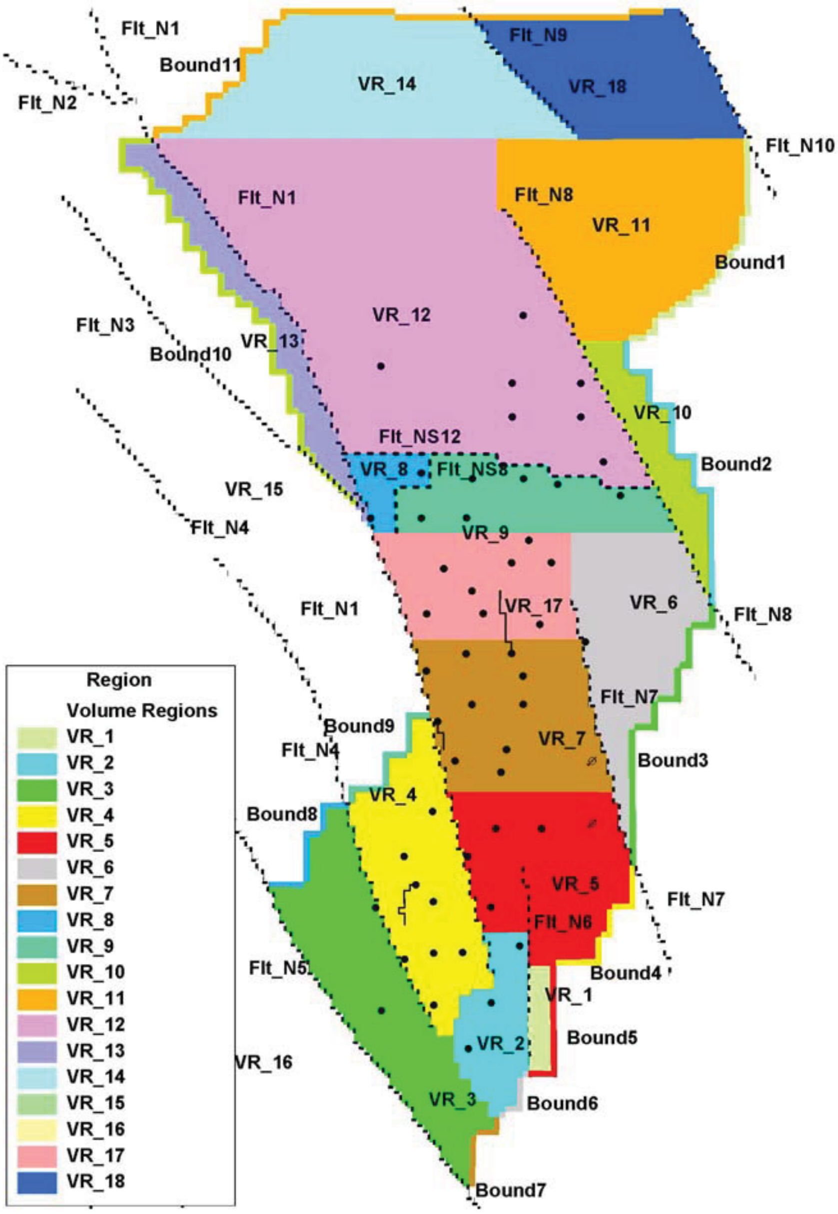

Figure 4.2: Wells, volume region, boundary and fault names of CON55 Field (#W block) (from Mittermeir[41], modified by the author)

4.2.2 Reservoir parameters

In the geological model, the CON55 reservoir was subdivided into seven lithostratigraphic zones (G1-G7) which were correlated based on electric log patterns. The reservoir quality in each of these zones is highly variable, which is attributable to variations in pore size. The variability in reservoir quality is represented in the geological model by four facies types. The distribution of petrophysical properties in the geological model is conditional on the facies model. Nevertheless the average porosity, permeability, and net to gross ratio per reservoir zone are nearby identical: porosity 0.26-028, NTG ratio 0.8-1.0, permeability 21-28 mD.

It is evident that no differences in average petrophysical properties exist between the lithostratigraphic zones. Therefore - even though each zone is characterized by diagnostic log patterns - the reservoir zonation does not reflect variations in reservoir quality[16].

In addition to the variations in facies type, fracturing was found to be a significant control on productivity in the CON55 Field.

The integration of productivity indices with faults interpreted in the CON55 Field indicates that productivity decreases with increasing distance to faults. This suggests that damage zones exist around the major faults in the field, in which the permeability is locally enhanced by fracture swarms that are oriented parallel to subparallel to nearby faults.

4.2.3 Grid and Upscaling

The grid size in the static model is 50x50 m and the vertical resolution is 84 layers. For the generation of a simulation grid, the author decided, after consultation with Heinemann[24], Egger[16] and Harrer[20], to maintain the grid block size of 50x50 meters from the geological model; the top and base surfaces of the simulation model are exactly identical with the geological model.

As the geological reservoir zonation does not reflect reservoir quality, it was found appropriate to replace the geological zonation by twelve simulation layers, whose thickness varies proportionally to the total thickness of the Gheriat reservoir. On the other hand side the 12 layers could easily represent these zones if it would turn out that they offer any advantages.

Porosity, permeability, water saturation and the net to gross ratio were upscaled into the simulation grid by volume weighted arithmetic averaging of the grid properties of the geological model. A cross section through the geological model and the simulation model is shown in Figure 4.3.

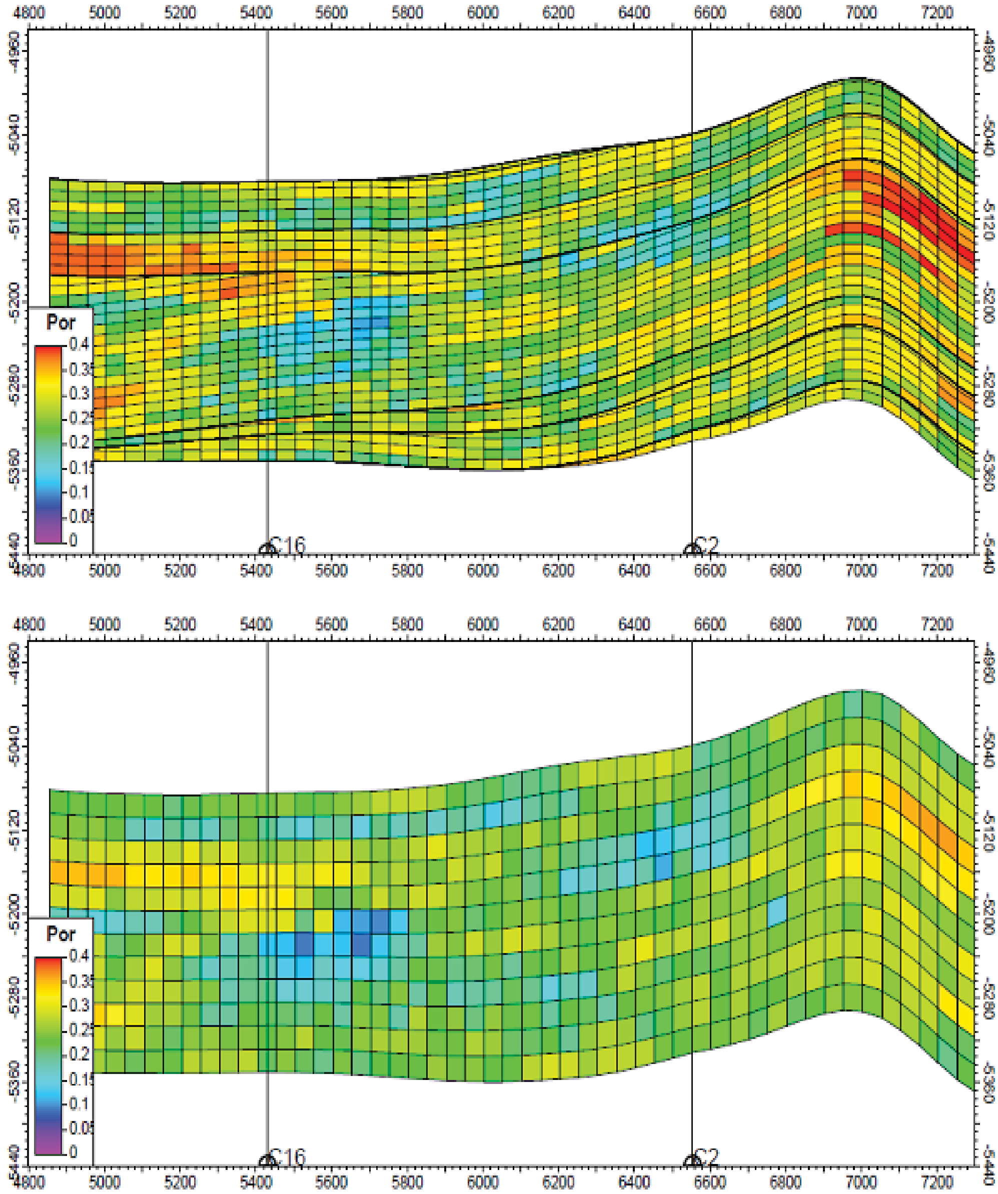

Figure 4.3: East-west cross section through wells C16 and C2 showing porosity of the geological model (top) and the simulation model (after Davis and Egger[13], modified by the author)

Water saturation was modeled using a water saturation profile established from interpreted saturation logs as an external trend. Figure 4.4 shows three cross sections. The top pictures show the saturation distribution modelled on the geological grid together with the G1-G7 zones. The cross section in the middle of Figure 4.4 shows the upscaled water saturations. Finally, the water saturation distribution used for the simulation model and calculated based on a free water level surface and a capillary pressure function is shown at the bottom of Figure 4.4.

As it can be seen in the top picture of Figure 4.4, there is no sign for any relationship between these zones (G1-G7) and the saturation distribution. To the contrary, the two seem to be independent of each other and zonation does not suggest the possibility of establishing a more detailed initial saturation distribution or to distinguish between different rock regions.

Considering that the connate water saturation is estimated to be 0.15 (based on log data, even lower) the reservoir has an unusually thick transition zone. The extension can be 150 ft or more. Therefore, up to 50% of the thickness of the oil zone contains movable water.

In addition, the distribution of movable water within the reservoir seems to be random. The saturation in the geological model represents a realization from an unconditional stochastic simulation.

Neither the lithostratigraphic zones nor the usual vertical equilibrium concept offers a guide to the appropriate initialisation and is a portent of difficulties in matching the watering out behaviour of individual wells.

The free water level (FWL) of the North part of CON55 field was determined at a depth of 5268 ft SS. Because all attempts to devise a reasonable zonation failed, only two possibilities remained:

- Non-equilibrium initialisation (NEQLI) using the saturation distribution from stochastic simulation without change.
- Equilibrium initialization (EQLI) using a single capillary function for the entire reservoir thickness. The function can vary laterally; that is, the function can be different in each rock region.

The first conceptual simulation model was NEQLI initialized. The stochastic simulation approach honoured the random distribution of rock types and because of this also resulted in a random distribution of water saturations.

Such an initialization approach is appropriate from a statistical point of view[20]. Figure 4.5 shows a typical cross section. Because the simulation is not conditional, every stochastic realization will have globally similar saturation distributions but the value at a given location, such as a single perforation, will be different.

Global history matching can be based on such a stochastic model of the reservoir fluid distribution; the calculated average water cut of a large number of realizations will fit the history. However, a well-by-well match cannot be established by this unconditional method. Such a well-by-well match requires either a conditional stochastic or a deterministic distribution of the phases.

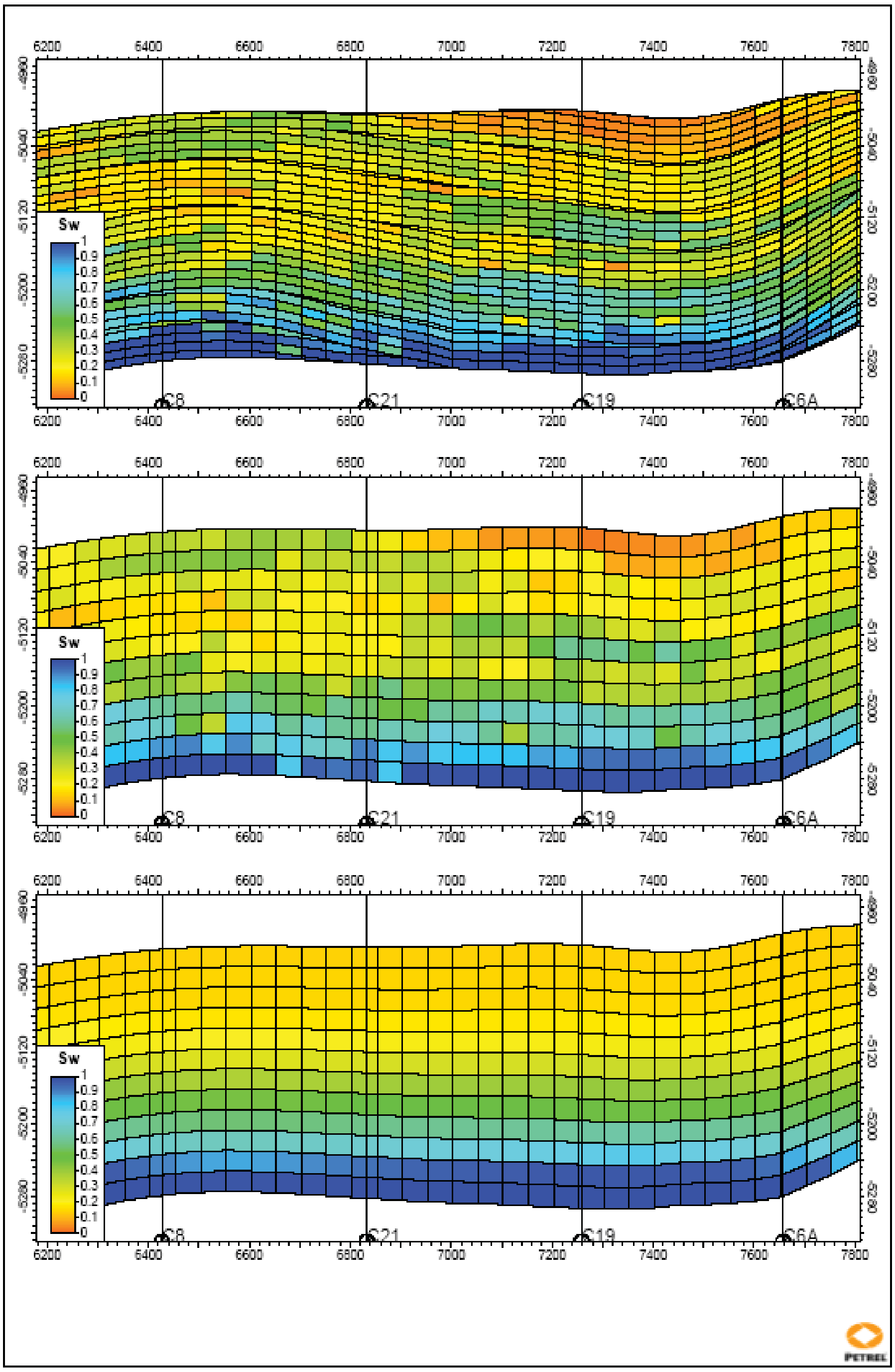

Figure 4.4: Cross section through wells C8, C21, C19 and C6 showing log derived water saturation of the geological model (top), showing log derived water saturation of the upscaled geological model and water saturation of the equilibrium initialization in the simulation model (after Davis and Egger[13], modified by the author)

The top and the bottom cross sections in Figure 4.4 compare the results of the NEQUI and EQUI approaches. HOL decided to use the EQLI initialization approach, following the principle of Khalid Aziz[4]: "keep the model as simple as possible and make it as complex as necessary". For the following history match, keep in mind the possibility that water could break into a well at higher structural position and not solely at the bottom. Figure 4.5 compares a well log with the water distribution in the simulation model.

As a consequence of the initialisation approach used, the simulation model probably will have a different vertical saturation distribution than the actual distribution. The lateral distribution of the phases will be probably realistic but the vertical distribution will certainly not.

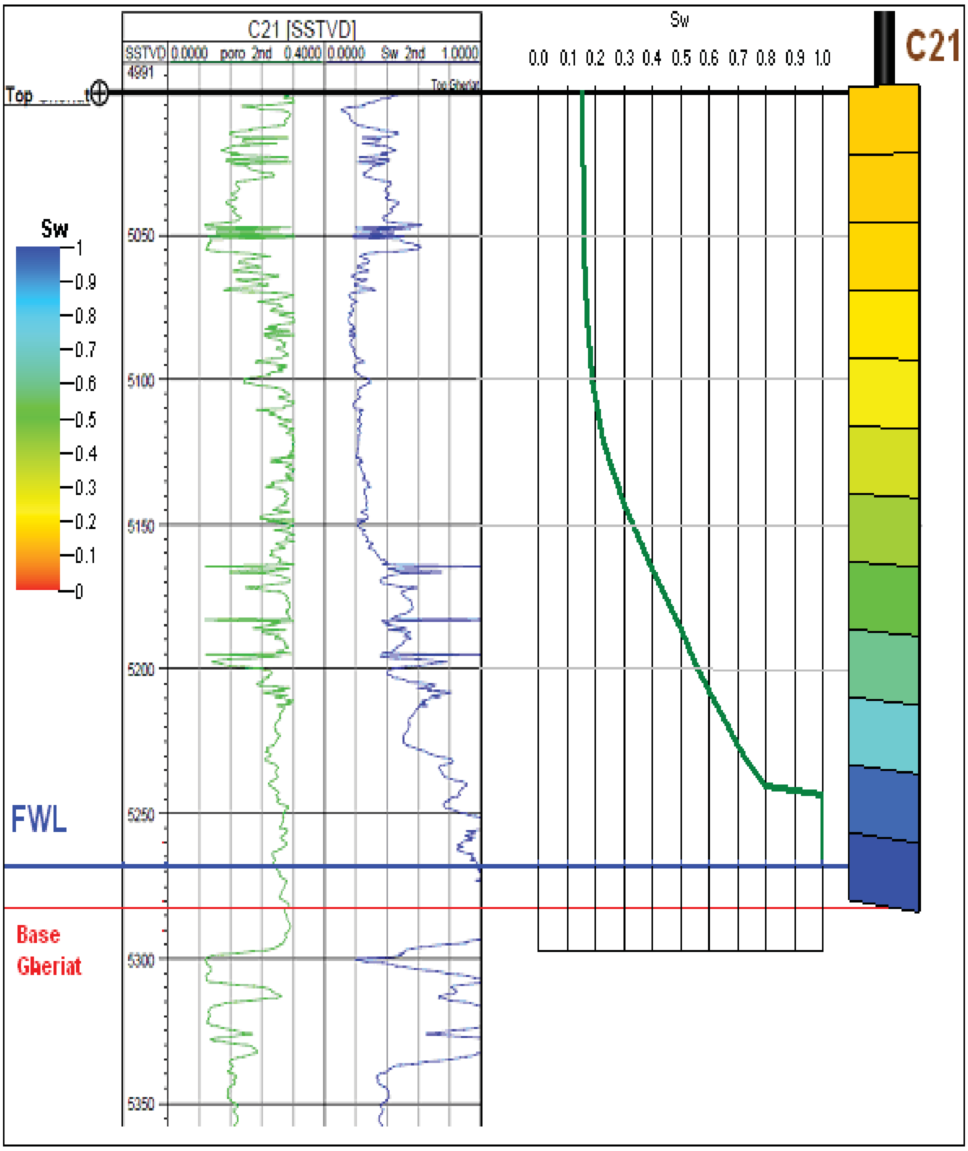

Figure 4.5: Porosity and water saturation log, capillary pressure function and block water saturations for well C21. Comparison of "reality" and "model".

4.3 Field Production

A total of 59 wells have been drilled in CON55 field throughout its history (for the newest wells C60, C61 and C62 no production information was available). 47 of them were actually contributing to the field's cumulative oil production which exceeded ### million STB in 2007. Then wells were outside the main hydrocarbon bearing zone (C01, C04, C05, C09, C11, C12, C13, C14, C15, C20 and C47; C12 produces from a separate sector in the south).

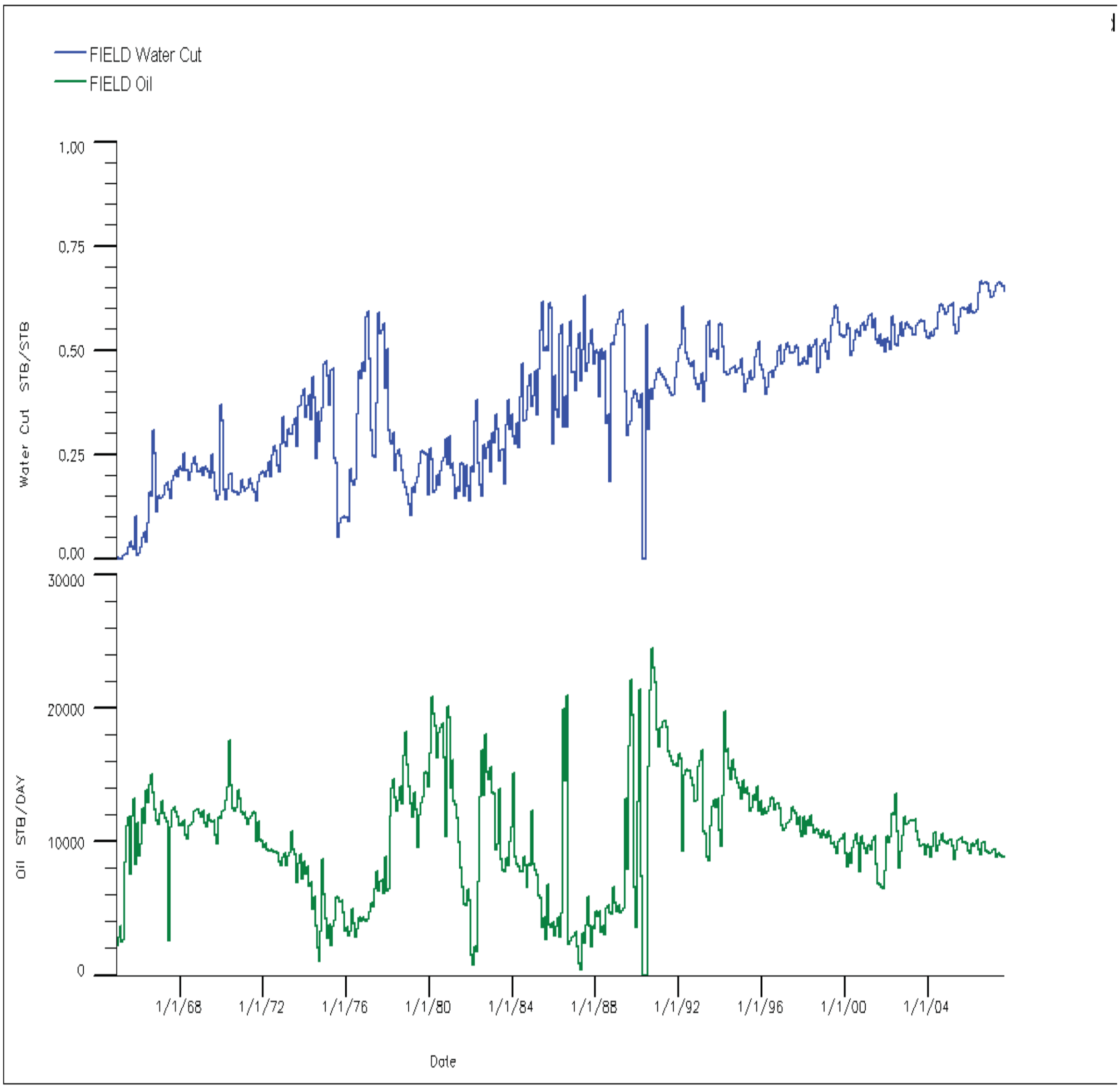

Figure 4.6: Field Oil Production (green), Water Cut (blue) .

Figure 4.6 displays the historical field oil production and water cut between 1964 and 2007. Production from CON55 reservoir commenced in December 1964.

4.4 Reservoir Pressure

The initial reservoir pressures of both blocks are hydrostatic, 2450 psia at the reference of depth 5100 ft SS. The pressure declined during the production from 1964 until 2008 to 1500 psia in average. Figure 4.7 shows the static BHP's for all wells. The high scatter in pressure data is an indicator for the existence of different pressure regions, which are separated from each other by at least partially sealing interfaces e.g. faults. Based on the different pressure behaviors the reservoir was divided in 9 pressure/volume regions, showed in Figure 4.2. Figure 4.8 is an example for this data separation. Figure 4.9 shows the average pressure development for all volume regions. At the end of 2008 the pressure is with 1000 psia the lowest in the middle of the reservoir (regions 7) and with 2000 psia the highest in North (region 12).

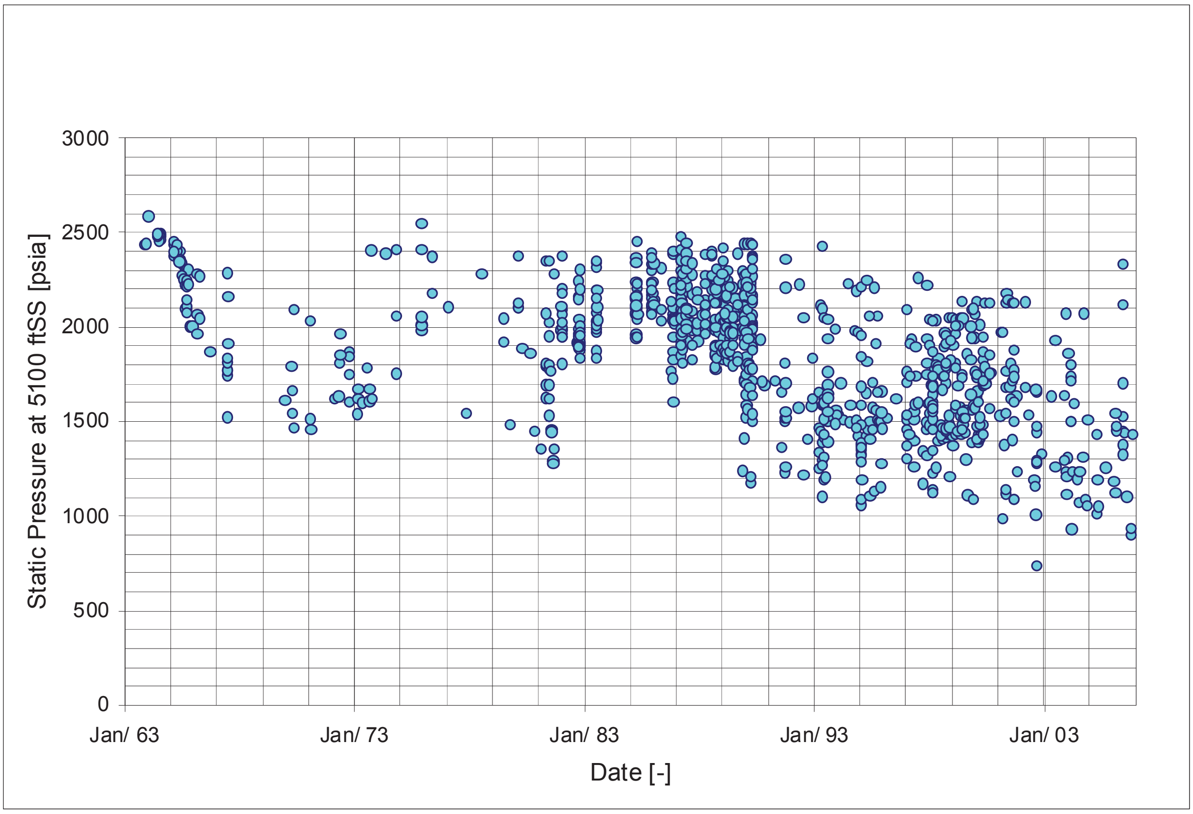

Figure 4.7: Static BHPs of all wells of entire #W Block.

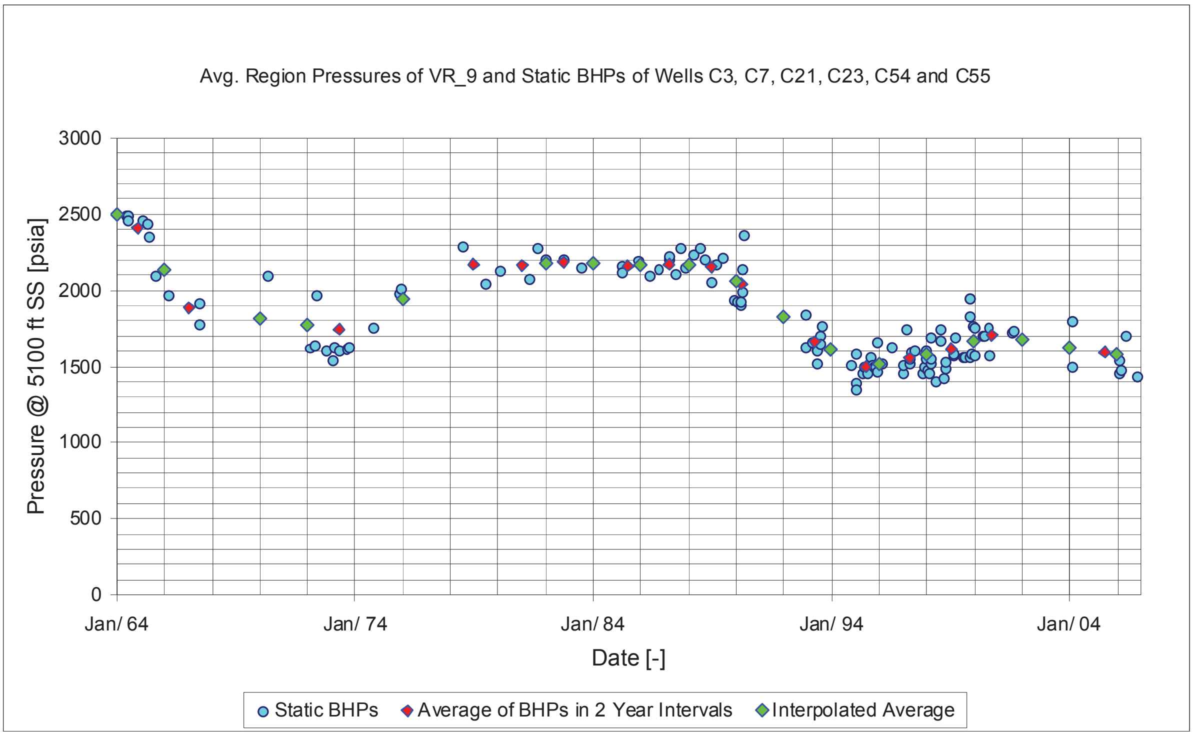

Figure 4.8: Static pressures of wells within region VR_9.

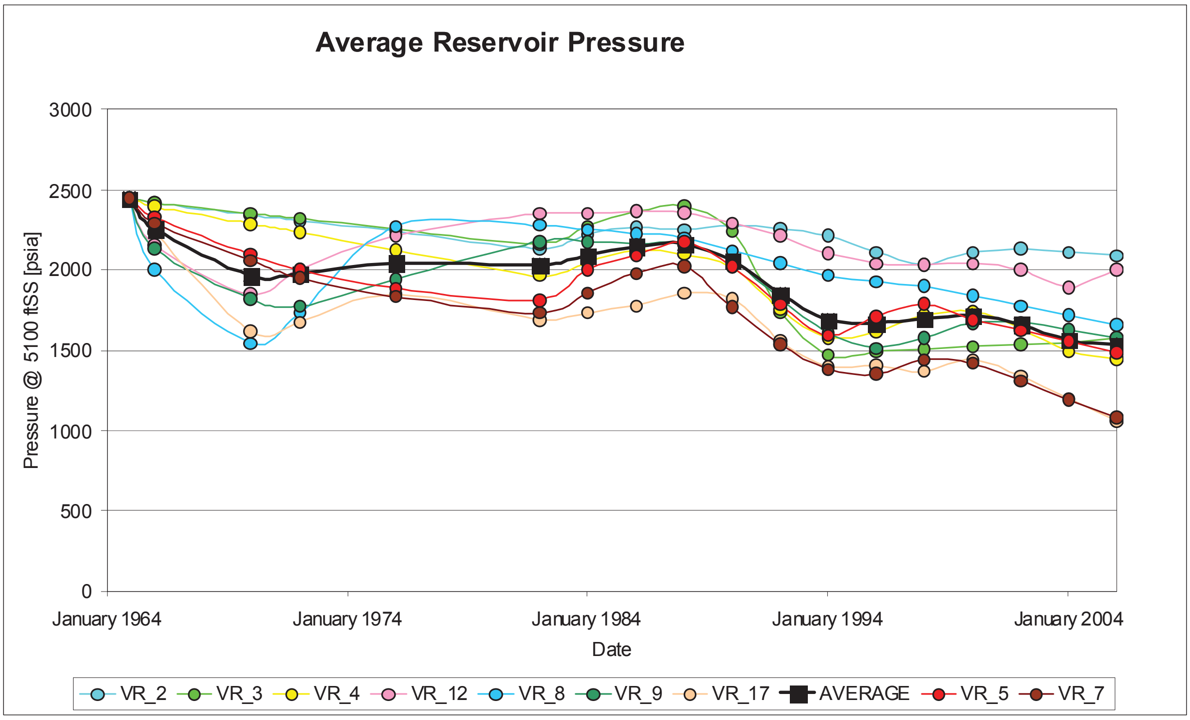

Figure 4.9: Average pressures for individual segments and HCPV weighted reservoir pressure for the entire field.

4.5 Water Influx

Material Balance calculations on the bases of the volumetrically calculated OOIP, historical production and average reservoir pressures resulted in a water drive index of > 0.8. The calculated water influx from the outer aquifer was around of 250 MMstb. The Fetkovich type analytical aquifer model gave the best fit. The material balance calculation does not define from which side the water was coming. In spite of the existence of mobile water below most of the wells, the general character of the depletion is not a bottom water drive. Regarding most of the wells the main flow direction is in lateral direction. Regarding the reservoir structure given in Figure 4.1 and Figure 4.2 it seems to be sure that this can be quite uneven. To locate the water influx, the boundary must be segmented.

Figure 4.2 shows the boundary segments numbered from Bound1 to Bound11 as theoretical posibilities. After examining the lateral pressure gradients and the watering of the wells in detail the following boundaries were identified as active: Bound1, Bound3, Bound4, Bound6, Bound8 and Bound9.

4.6 Extracted Single Well Models

Caused by strong edge water inflow the CON55 wells do not posses individual drainage areas which could be regarded as an independent model. For this reason no HM can be performed on single well models. In spite of that one grid cube and one cross section were extracted by the author from the already matched full field grid at the position of the well C18, shown in Figure 4.10 and Figure 4.12. The well C18 was selected because it is characteristic for the field, it has a long and continuous production history and operates under direct aquifer influence. The parameters within the the models were slightly modified.

These two grid models will be used to examine certain behaviours and to explain the concept and methods appied in the full field modeling. Note that these calculations are modelings and not simulations. The results mirror the nature of the happenings, but do not offer quantitative information about the well performances.

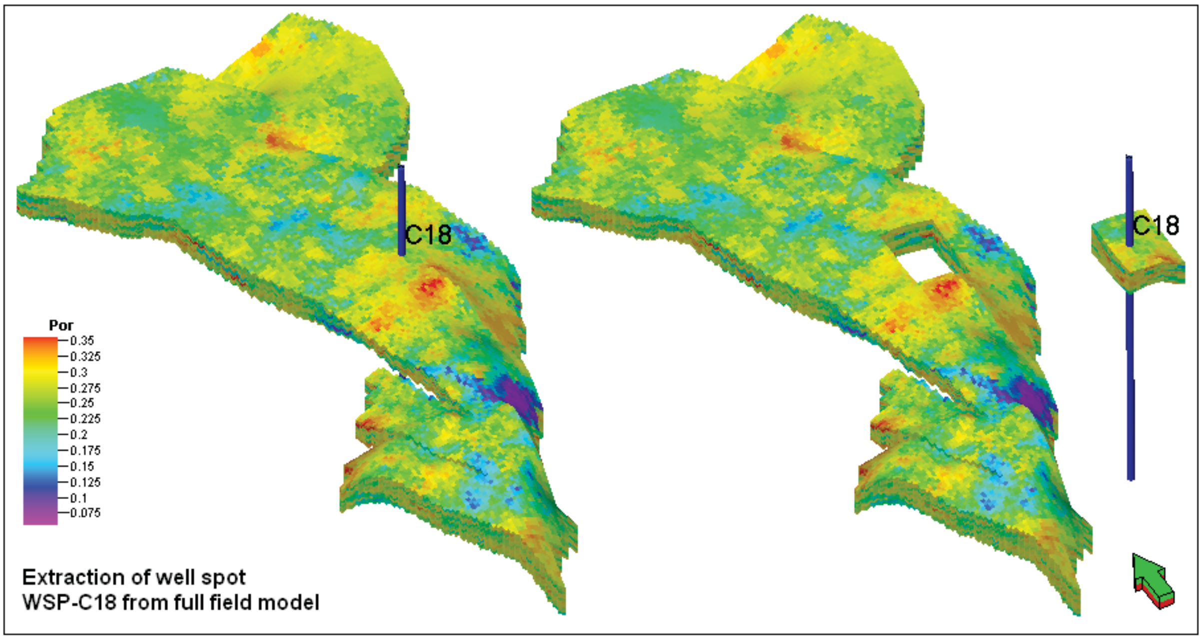

Figure 4.10: C18W well spots were extracted from the full field model .

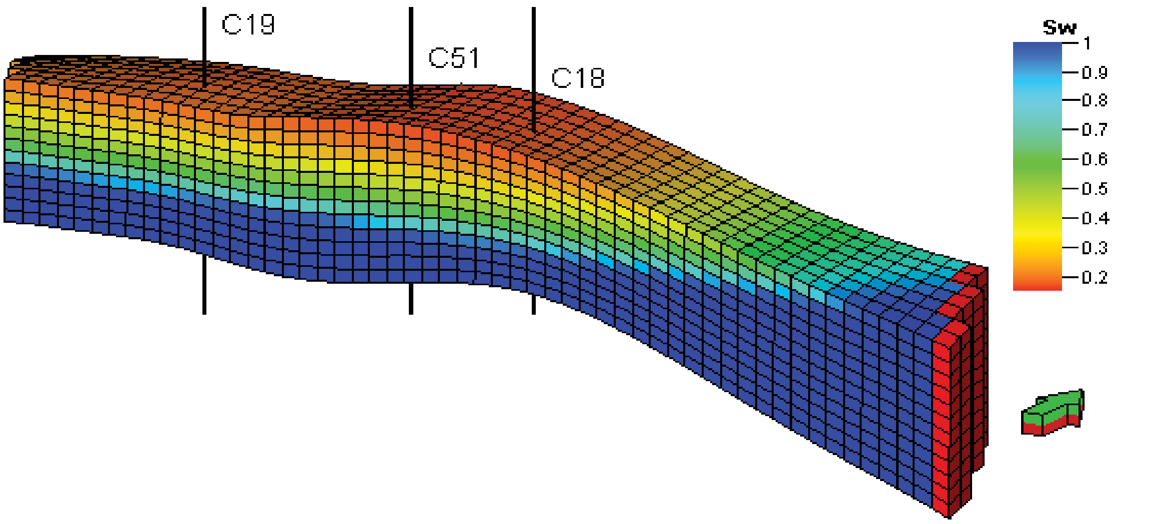

Figure 4.11: 3D view of cross section model showing wells C18, C19 and C51, initial water saturation distribution and location of water influx boundary (red blocks) .

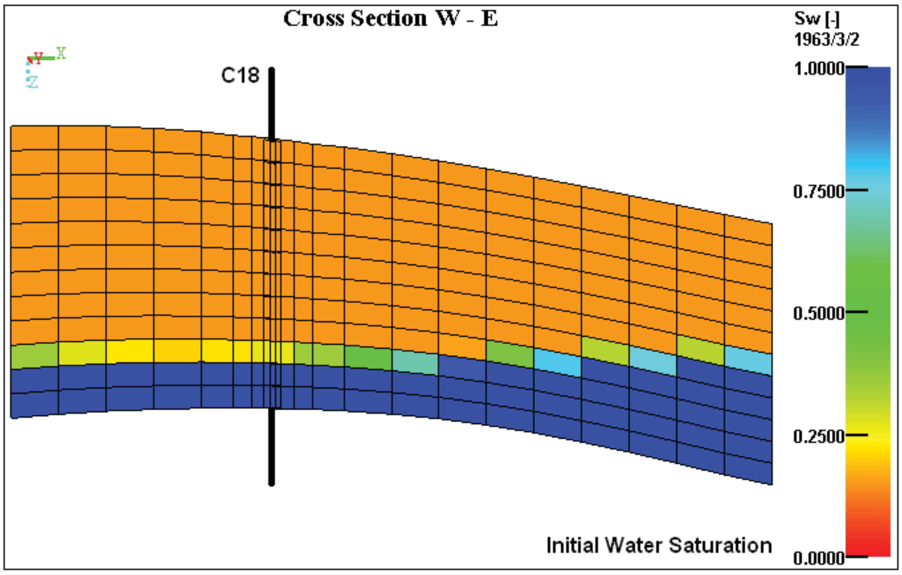

Figure 4.12: Initial saturation distribution of C18W single well model, with a cross section trough of the well.

The well model has an extent of 800 x 1050 m, and a thickness of 80 m average. The areal grid size is 50 x 50 m. The model consists of 16x21x12 = 4032 grid cells. The model was equilibrium initialized using the capillary pressure curve given in Figure 4.5. Figure 4.12 shows the initial saturation distribution. The OOIP in this well spot model is 6.14 MMstb. On the right hand side, there is a boundary for water influx from the aquifer. Figure 4.13 displays the production history of the well C18.

Both the single well model and the cross section is situated in volum region VR_17 (see figure 4.2). The region pressures are displaid on Figure 4.9.

The cross sction model described in Figure 4.11 consists of 4548 blocks. The original oil in place equals 28.8 MMstb and the initial water volume equals 79.5 MMstb. The initial pressure was calculated to be 2439 psia. All wells produced with the historical oil and water rates during the numerical experiments and the corresponding average region pressure was defined as target pressure.

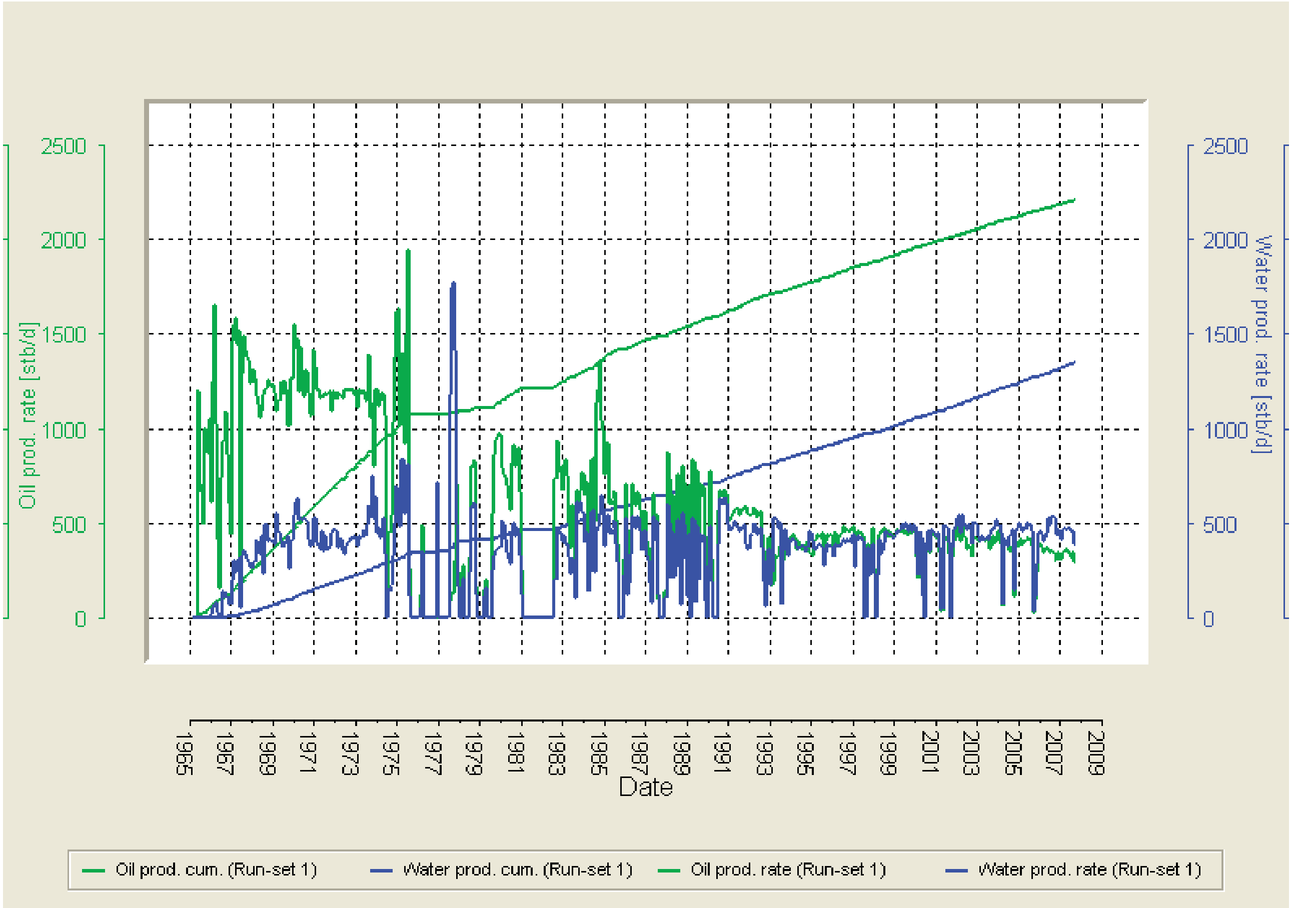

Figure 4.13: Production history of the well C18 and the target pressure assigned to the C18W model

Chapter 5

Validation of the Target Pressure and Phase Method

5.1 Introduction

This chapter describes the handling of the pseudo wells and their relation to the corresponding real wells. It will be presented how pseudo wells can be used to match near well properties, fractures and coning behaviors. A single well and a cross section model will be presented to show that in certain cases the pseudo well is the only practical solution.

Nevertheless **TPM** is still an iterative procedure; the analytical aquifer parameters are valid after all the wells produce exactly the historical rates of all components (in black oil model the oil, gas and water). For that, the model must be tuned. In a first step the geological model will be revised (validated), then the production, PVT and SCAL data are checked and corrected within the confidence range[24], then also beyond that, followed by different kind of "pseudos" (e.g.: directional or perforation specific relative permeabilities), interbeddings and low and high permeability strikes, baffles and channels, but the goal will be never achieved[26]. Some differences between the model and reality always remain. At the end the reservoir parameters were tuned and the well model was adapted losing the confidence in both of them.

It is a justifiable question if the wells are identifiable and stable objects in a reservoir model or not. Already the localization of the effective well-reservoir connection is difficult and the inflow performance changes by cement and casing failure, scaling etc. over time. The skin factors determined in subsequent tests can easily show 200% or 50% of the previous value. It makes no sense to try to model a well with constant parameters over longer time (10, 20 or 40 years), especially not for the history. A "matched well" has no relevance.

The word "validation" in the chapter title is perhaps not the best expression at this place. The TPPM is not a mathematical model and not a solution which can be compared to measurements, observations or results from other theoretical approaches. Nevertheless it is possible to explain the application of TPPM in more detail and to present simplified and easier understandable cases. The objective of this chapter is to help the reader to understand the pseudo well concept and persuade him of its applicability.

In the following, three kinds of wells will be addressed:

- the real well which exists in the field,
- the model well representing the real well in the reservoir model
- the pseudo well, that masks the real well during the model building process.

The model well, as the name suggests, should represent the real well as good as possible. Amongst others, it should have the same trajectory and the same perforations as the real well. Supplementary the calculation of the well inflow should be accurate, which requires correct analytical or gridded inflow models. Also if both, the reservoir and the well models are the best possible ones, the linked reservoir well model will not fit the historical production rates, GOR, WC and observed reservoir, bottom hole and well head pressures; at least not in the early stage of a modeling process. The objective of HM is to achieve that the rates, WC, pressures, etc. fit to the reality.

The main difference between the classical and the proposed approaches is easy to explain:

- In a classical approach, both the reservoir and the wells are “correctly” described but their modelled and measured behaviors will be different.

- In the new approach the pseudo well behaves as the real one, has the same rates, WC, pressures, e.t.c., but is different to the real well. The objective is to force the pseudo well to converge with the real one.

5.2 Well Models

5.2.1 Inflow performance

Wells can be represented in a reservoir model as simple volume sources, or as the well known Peacemen well model[50,30] or at the end of the list as an independently gridded object with skin zone, cement bound, casing, perforations, tubing, valves, pump and well head. Regarding the pseudo wells the most simple approach, namely the Peacemen well model[50,30] is certainly satisfactory.

The inflow rate of the phase p from a perforation (also called "connection" in Eclipse) I will be calculated by the following equation:

$$q_{pI}^{n+1} = J_I(\lambda_p D_p)_I^{n+1}[p_{pI}^{n+1} - p_{wfp}^{n+1} - \rho_t^n g(z_I - z_{ref})], \tag{5.1}$$

where:

$\lambda_p = k_{rp}/\mu_p$ - is the mobility of phase p at the perforation (connection) I [1/cP]

k_{rp}	-	the relative permeability of the phase p at the perforation (connection) I [-]
μ_{rp}	-	viscosity of the phase p from the perforation (connection) I [cP]
q_p	-	rate the phase p from the perforation (connection) I [kmol/d]
J	-	perforation (connection) transmissibility [...]
D_p	-	mole density of phase p in the perforation (connection) I [kmol/m^3]
p_p	-	pressure of phase p in the perforation (connection) I [bar] at z_{ref}
p_{wf}	-	well bottom hole pressure [bar] at z_{ref}
z_{ref}	-	reference depth [m]
z	-	vertical depth of the grid point I [m]
r_t	-	average flowing density in well between z and z_{ref} [kg/m^3]
g	-	gravitation constant [m/s^2].

The perforation transmissibility J is calculated based on the *Peacemen*[50] well model. The Equation 5.1 is also given in ECLIPSE terminology in Figure 5.1.

Writing Equation 5.1 in more compact form:

$$q_{pI} = \Upsilon_I[p_{pI} - p_{wfp} - d_I], \tag{5.2}$$

where

$$\Upsilon_{pI} = J_I(\lambda_p D_p)_I \quad \text{and} \quad d_I = \rho_t g(z_I - z_{ref}). \tag{5.3}$$

The well rate is the sum of the perforation rates:

$$Q_p = \sum_{I=1}^{N} \delta_I q_{pI} = \sum_{I=1}^{N} \delta_I \Upsilon_{pI}[p_{pI} - p_{wfp} - d_I] \tag{5.4}$$

where

$$\delta_{pI} = \begin{cases} 1 & if \quad perforation \ldots open \\ 0 & if \quad closed \end{cases} \tag{5.5}$$

$$p_{wfp} = \frac{\sum_{I=1}^{N} \delta_I \Upsilon_{pI}(p_{pI} - d_I) - Q_p}{\sum_{I=1}^{N} \delta_I \Upsilon_{pI}} \tag{5.6}$$

During the history match the oil, water and gas rates (Q_o, Q_w, Q_g) are known. The free gas rate (Q_{Fg}) can be estimated from the gas rate and the average pressure in the drainage area:

$$Q_{Fg} = Q_g - Q_o R_s(\bar{p})\,. \tag{5.7}$$

Now three different bottom hole pressures can be calculated shown in Equation 5.6 which are non-physical values. In the classical approach a single bottom hole pressure will be calculated using net or wet reservoir rates as target. The model well is operated normally with target wet rate by water drive and by target reservoir volume by solution gas or gascap drive. For target wet rate the bottom hole pressure is:

$$p_{wfb} = \frac{\sum_{I=1}^{N} \delta_I (\Upsilon_o + \Upsilon_w)_I (p_{oI} - d_I) - Q_b}{\sum_{I=1}^{N} \delta_I (\Upsilon_o + \Upsilon_w)_I} \tag{5.8}$$

The apparent bottom hole pressure and the calculated WC and GOR are the measures of the HM quality.

(5.9)

Inflow performance relationship in ECLIPSE 100

In ECLIPSE 100 the inflow performance relationship is written in terms of the volumetric production rate of each phase at stock tank conditions:

$$q_{p,j} = T_{wj} M_{p,j} (P_j - P_w - H_{wj}) \quad \text{[EQ 65.1]}$$

where

$q_{p,j}$	is the volumetric flow rate of phase p in connection j at stock tank conditions. The flow is taken as positive from the formation into the well, and negative from the well into the formation.
T_{wj}	is the connection transmissibility factor, defined below.
$M_{p,j}$	is the phase mobility at the connection.
P_j	is the nodal pressure in the grid block containing the connection.
P_w	is the bottom hole pressure of the well.
H_{wj}	is the well bore pressure head between the connection and the well's bottom hole datum depth. $P_w + H_{wj}$ is thus the pressure in the well at the connection j, which we call the "connection pressure".

Figure 5.1: Inflow performance relationship in ECLIPSE 100 (from Eclipse Manual[58])

5.2.2 Productivity Index

To calculate the BHP on the bases of the perforation parameters is relatively uncertain and is difficult the verify. Production logging will be rarely made and the results also have limited validity over time. In contrary to this, production tests will be carried out often and the productivity indices of the wells are regarded as being known all the time:

$$PI = \lim_{\Delta p - 0}\left(\frac{Q}{\Delta p}\right). \tag{5.10}$$

where

$$\Delta p = \bar{p} - p_{BHP} . \tag{5.11}$$

and Q is the reservoir volume rate of the well (in a single phase case also surface rate can be used) and $\bar{p}$ is the static well pressure. The target bottom hole pressure is then:

$$p_{BHP} = \bar{p} - \frac{Q}{PI}, \tag{5.12}$$

where both $\bar{p}$ and p_{BHP} are calculated at the reference depth. The well by well pressure matching can be based only on these three quantities: Q, $\bar{p}$ and p_{BHP}. The BHP can be measured directly, the reservoir rate can be calculated with confidence, especially in the absence of free gas. Measuring static pressures is sometimes delicate but there is no alternative.

The static pressures will not be calculated in a numerical reservoir model either. They will be estimated using questionable averaging methods as WPAVE in ECLIPSE[58]. But at the end of the day these two pressures ($\bar{p}$ and p_{av}) will be compared and regarded as measure of the HM quality. *Klima*[36] suggested that the comparison should be constraint by the *PI*, regarding it as realistic and hard data. From a practical point of view it is better to determine or estimate the productivity indices and to use them to improve the quality of the history match.

5.2.3 Estimation of perforation rates

At this point the calculated phase bottom hole flowing pressures from Equation 5.4 are different for the phases. This discrepancy can be eliminated by tuning the transmissibility of the perforations. The following procedure was suggested by *Klima*[36].

Consider the time period $<t_a,t_b>$ in which no recompletions took place, the productivity index *PI* is known (and can be regarded as constant) and the (pseudo-) perforations were not changed. Choose *K* time step within this period (the number of time steps in the period is > K). Depending on the number of mobile phases 1 to 3 equations can be written for the K timesteps according to Equation 5.4. If all quantities in this equation would be realistic and exact, then the difference in phase bottom hole pressures would be the capillary pressure only. This difference is small, can not be measured (and so can not be verified either) and therefore it should be neglected[27]:

$$p_{BHPoj} = p_{BHPwj} = p_{BHPgj} = p_{BHPj} . \tag{5.13}$$

The common BHP results from Equation 5.12: (5.14)

$$p_{BHPj} = \bar{p}_j - \frac{(B_o Q_o + B_w Q_w + B_g Q_{Fg})_j}{PI} \tag{5.15}$$

where PI is taken from production tests and $\bar{p}_j$ is calculated by the averaging method in use (*WPAVE* option). Equation 5.4 can be written in a compressed form:

$$\sum_{I=1}^{N} e_{pIj} \delta_I = Q_{pj} , \qquad j = 1, \ldots, K, \tag{5.16}$$

where

$$e_{pIj} = \Upsilon_{pI} [p_{pI} - d_I - p_{BHP}]_j . \tag{5.17}$$

In this work the case with 3 mobile phases (with free gas) was not really handled, also here two phases, oil and water will be considered. Writing Equation 5.18 for this phases 2*K equations will be achieved containing N unknowns where N << 2*K:

$$\sum_{I=1}^{N} e_{wIj} \delta_I = Q_{wj} \tag{5.18}$$

$$\sum_{I=1}^{N} e_{oIj} \delta_I = Q_{oj} \tag{5.19}$$

Not that this equations brought the measurements (PI) and the well model to a common denominator.

In Equation 5.5 δ_I equals 1 if the perforation is open and 0 if not. Now it is suggested to regard d_I as a correction factor for the perforation. The Equation 5.18-Equation 5.19 should be valid over a longer time period with the smallest possible errors, keeping δ's constant. The unknown in these equations are therefore the perforation transmissibility multiplier δ_I.

They can be determined solving the Gauss normal equations:

$$\eta_1^1\delta_1 + \eta_2^1\delta_2 + \ldots + \eta_N^1\delta_N = \sum_{j=1}^{M} (e_{o1}Q_o + e_{w1}Q_w)_j$$

$$\eta_1^2\delta_1 + \eta_2^2\delta_2 + \ldots + \eta_N^2\delta_N = \sum_{j=1}^{M} (e_{o2}Q_o + e_{w2}Q_w)_j \quad (5.20)$$

$$\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots$$

$$\eta_1^N\delta_1 + \eta_2^N\delta_2 + \ldots + \eta_N^N\delta_N = \sum_{j=1}^{M} (e_{oN}Q_o + e_{wN}Q_w)_j$$

where

$$\eta_i^{i'} = \sum_{j=1}^{M} (e_{oi}e_{oi'} + e_{wi}e_{wi'})_j \quad i' = 1, \ldots N \quad (5.21)$$

and

$$\eta_i^{i'} = \eta_{i'}^{i}. \quad (5.22)$$

Unfortunately the theoreticaly elegant procedure described above does not work, resulting in non physical d_I values (i.e.: negative) in most of the cases. Experiments showed that a practical solution could be to restrict the multiplier to two values. The first is applied to perforations having a higher water cut as the target, the second used for the remaining ones. This solution was applied also to the field example presented in Chapter 6.

5.2.4 Crossflow

Crossflow is a well known phenomenon in wells, that are producing commingled from more layers separated by interbeddings. It is physical and therefore important to handle the crossflow in shut in wells. In wells producing continuously the crossflow is apparently more a numerical modeling, than a real problem. PRS offers two possibilities: The default solution is the *Modine* at *al*.[47] method applicable both to producing and shut in wells. The second solution simply eliminates the potential cross flows. In active wells the perforation PI's will be reduced by a common factor achieving that all of them become inflow (outflow for injectors) perforation. In shut in wells all perforations are plugged temporarily. TPPM introduces pseudo perforations and manipulates perforation productivity indices automatically to match the historical oil, water and gas rates. Which means that it is even not intended to capture the phase inflow from the individual perforations and therefore it is not possible to do it with the potential outflow (cross flow).

Therefore the second PRS solution will be applied only. The perforation multipliers determined by TPPM contain this kind of "cross flow factor" too.

5.3 Pseudo Wells

5.3.1 Setting of pseudo wells

Every history matching follows a hierarchical approach, going step by step from the global pressure match through the regional match to the well by well match. This work introduced an intermediate unit, called well spot, between the regions and the wells, representing more or less the drainage area of a well. Supplementary to the real wells, pseudo wells are introduced into the well spot. A pseudo well can, but does not have to be be, different from the real well. This means that it can have a different location, different perforations and artificial near well parameters as productivity indices, etc.. The only requirement for the pseudo well is, that it must be able to produce the same oil, gas and water rates as the real well all the time.

Generally it is no restriction how a pseudo well should be set. As already mentioned the objective of the matching process is to force the pseudo well to converge with the real one. Therefore the pseudo well should contain the real perforations in any cases. The supplementary perforations, called pseudo perforations, can be set along or on the extension of the real well trajectory, but they can also be arbitrarily distributed within the spot. In case of vertical wells, all layers above and below the real perforations should be declared. In case of horizontal wells also blocks outside of the trajectory laying in the vertical and/or in the horizontal plain can be considered. Generally speaking the well will be regarded as a pseudo multilateral well, having access to its entire drained reservoir volume if necessary. All these pseudo perforations should be introduced, for reasons of data management into the simulation software, at the model initialization and then be closed. They will be activated later if necessary.

The target phase rates will be distributed individually among the perforations based on Equation 5.4. Consequently two (or three) bottom hole pressures (BHP) will be obtained, differently for oil, water (and gas). The result is naturally not physical, but this is also not required at this stage. Important is only that all wells produce the reported rates over the entire history. If this is possible, then there is enough mobile oil, water and gas at the real perforations all the time and the model is globally right. If this is not the case, then the pseudo perforations can be opened one after one. If the well can not be operated even in such a way, then the available amount of oil, water and gas globally or locally is insufficient.

To be able to complete the actual run, the problem wells will be switched to wetrat control. Also the low permeability can constrain the wells by minimum bottom hole pressure.

Perforation transmissibility multipliers will be applied automatically to keep the model wells in operation. Note that as consequence of the ptarget option the reservoir pressure is always correct.

What the TPPM approach can do at this stage is easy to explain: The run informs the user which well construction (location and PI's of perforations) could produce the historical rates with the measured BHP at the offered reservoir structure and parameters within the individual spots (drainage areas). TPPM opens and closes pseudo perforations and assigns multipliers to the individual perforations to match the targets. The solution is naturally not unique. Therefore PRS offers options as matching, stretch, extend, average, forced, WPIMULT, WPIMULTP, with which the user can influence and constrain the automatic matching. In this way the TPPM provides pseudo wells telling the user "*if your reservoir spot looks so then I would need such a well to produce as happened.*" If the pseudo well differs considerably from the real well, than the reservoir geology must be updated. The quality measures of the reservoir description are the artefacts in the tuned pseudo wells. The objective of the fine re-parametrization of the reservoir model is to eliminate or at least to reduce the number (extension) of the pseudo perforations. In TPPM it is (should be) still forbidden to tune the dynamic model at this level of the project.

5.4 Single Well Modeling

The CON55 field operates under strong edge water drive. This was already established by conceptional models by *Mittermeir* et *al*[41]. Low and high permeable strikes, also if they could not correlate between the wells lead to early water break trough in structurally higher perforations.

In such a situation a well does not posses an individual drainage area, which could be regarded as an independent model. For this reason, no HM can be performed on CON55 single well models. The following calculations are therefore modeling and not simulation. The results mirror the nature of the happenings, but do not offer quantitative information about the well performances. In clear words, this chapter presents model calculations on the selected wells but not a simulation.

To keep the connection to the actual reservoir as close as possible the well C18 was selected for investigation and demonstration. The well spot, shown in Figure 4.10, was extracted from the already matched full field model. At the right hand side of the grid, there is the boundary to the aquifer.

The well C18 is situated in volume region VR_17 (see figure 4.2). Their average pressure, displayed on Figure 4.9, is used as target pressure. Figure 4.13 shows the historical oil and water productions.

Two grid models were applied:-

1. Cartesian grid, as in the full field model.

2. Well window, which can be plugged into the basic Cartesian grid, as shown in Figure 5.2.

The well window has a radial grid around the well bore with 7 rings. The inner ring is the well itself (with diameter of 7") and the second ring has a radius of 0.18 meter.

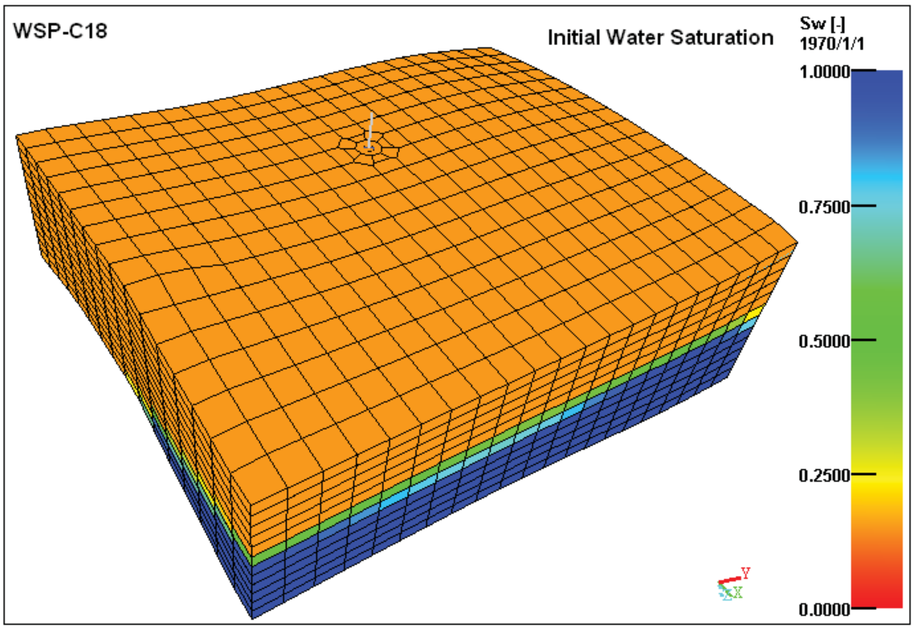

Figure 5.2: C18W well spot model with radial well window.

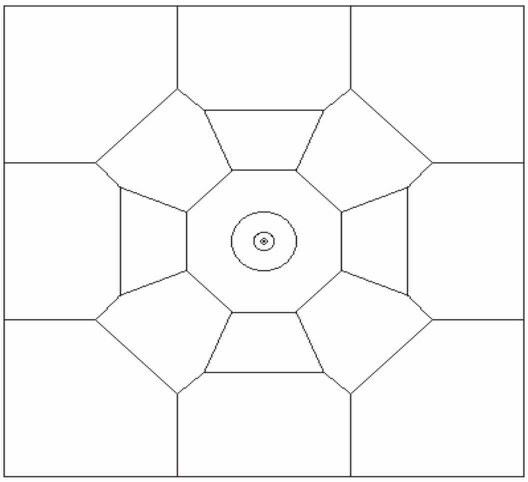

Figure 5.3: Window Grid (from Heinemann[23])

5.4.1 Experiment with constant rate

To demonstrate the problems, that the work faces in the case of CON55, the model was operated with constant gross production rate of 1000 BPD at first for three cases:

Case_A: The original Cartesian grid was used. The result is shown in Figure 5.4. The water shows up in the well after 20 years of production only.

Case_B: The radial window was introduced as shown in Figure 5.2. Figure 5.3 is the result of this grid. The water production starts already after 9 months of production and increases steadily, after 20 years and the water cut is 0.25. The difference between the Cartesian grid and the radial well window is, that the first one can not model coning behaviors but the second one can. Note that the difference between the two models is the grid around the well only. All model parameters are exactly the same.

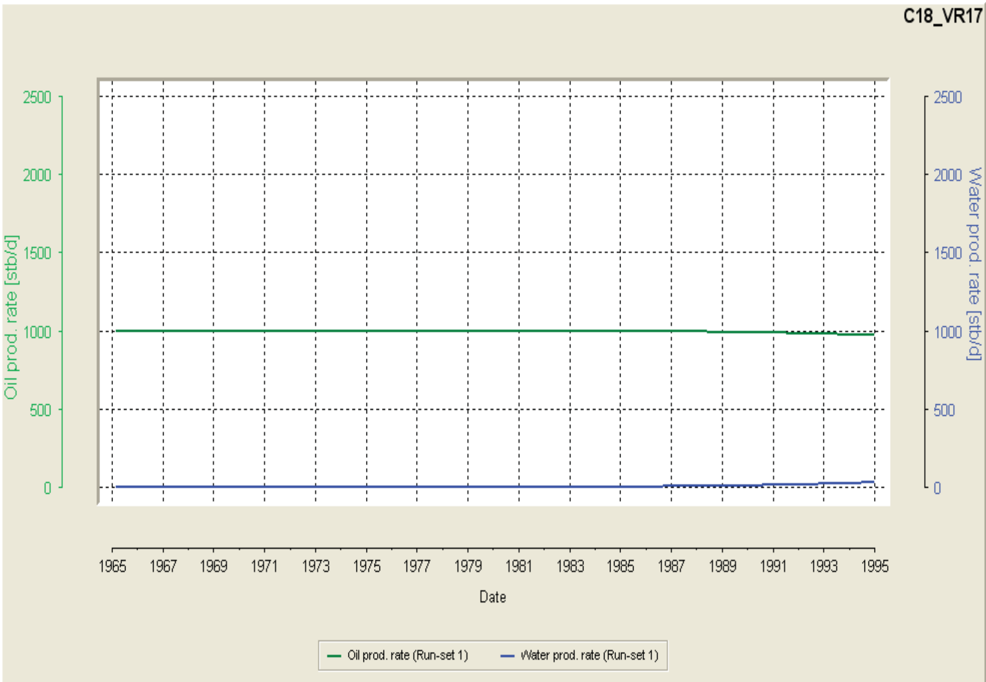

Figure 5.4: **Case_A**: Oil and water production rates of C18W model with Cartesian grid, 1000 BPD constant gross rate.

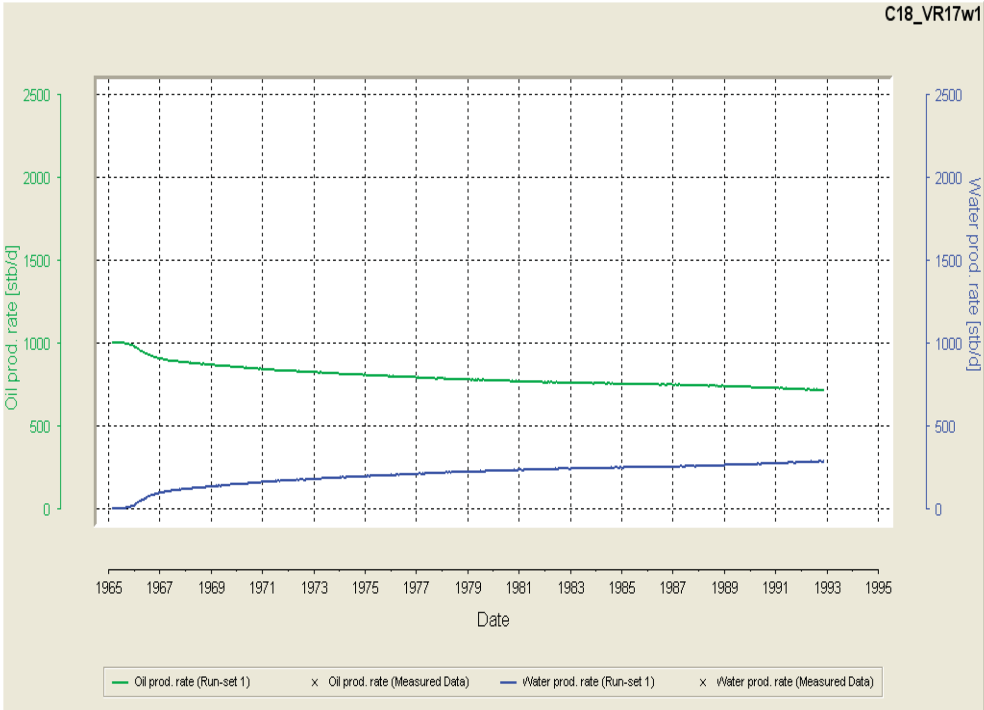

Figure 5.5: **Case_B**: Oil and water production rates of C18W model with radial well window;, 1000 BPD constant gross rate.

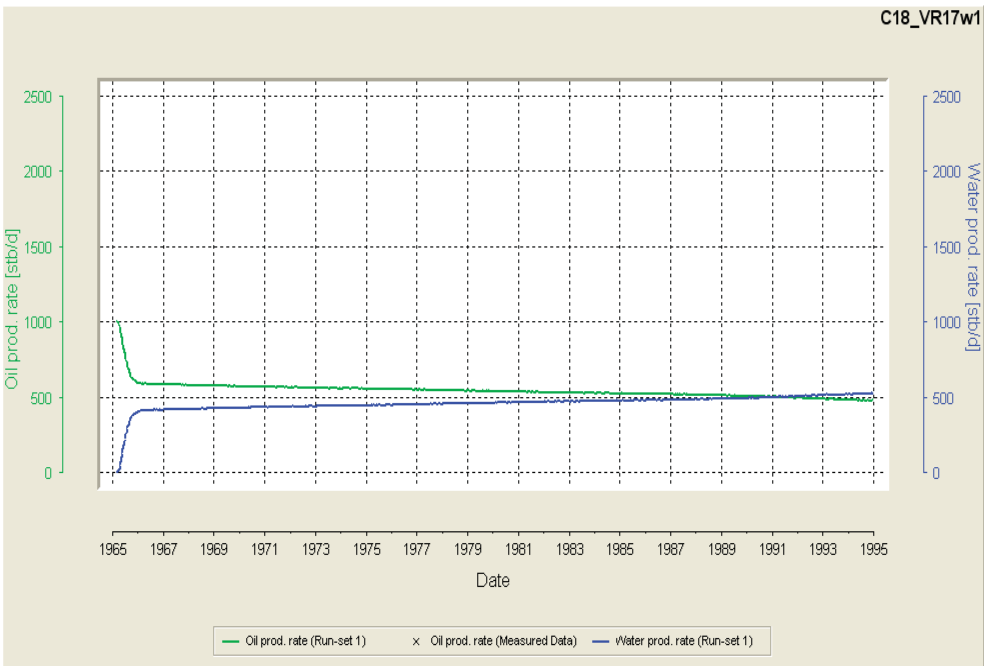

Figure 5.6: **Case_C**: Oil and water production rates of C18W model with radial well window and vertical fracture; 1000 BPD constant gross rate.

Case_C: It is assumed that CON55 is partly fractured, especially near to faults. Such fractures can enhance the productivity index considerably, as it was observed with many wells (also in C18), but they could be responsible for early water break through and high water cut also.

To simulate a possible vertical fracture the vertical permeability in the 2nd and 3rd ring was increased by a factor of 100.

This approximates a fracture with 0.6 m half-length and 1 mm width. Such a fracture has according Lamb's law 84400 Darcy of permeability (from Aziz[6]). This construction is not absolutely correct (theoretically it would be possible to grid the fracture too) but it is near to the perception.

The result is shown in Figure 5.6. The water breaks into the well within some months, the water cut is above 0.40 after one year and increasing to 0.50 after 20 years. Note that the nature of the watering in this case seems to be similar to the historical behavior of the real well C18, given in Figure 4.13.

Figure 5.7 compares the cases A, B and C. Assuming that the production in Case C is the "historical" one, two questions can arise:

1. Does TPPM match the history without introducing a radial well window and without assuming vertical fractures in vincinity of the well?
2. Can the matched model predict the future performance of "historical" model?

If the answer is no, than TPPM can be forgotten.

Case A was re-calculated with TPPM, taking the production from Case C as "historical". Figure 5.7 displays the oil and water rates for Case A, the "historical" Case C (light green and blue) and Case A with TPPM (dark green and blue).

The two last cases are nearby identical, so it must be shown in a magnification that there are some numerical differences. The number of pseudo perforations below the real ones is 5 at the beginning, then 4 and 3 at the end.

In the actual set up the transmissibility multiplier was applied to the deepest perforation, the other ones were multiplied with the reciprocal values. Figure 5.8 displays the number of perforations and the multipliers.

The "pseudo well" matched over 25 years could be used to predict the following 5 years with a fixed number of pseudo perforations and with constant multipliers.

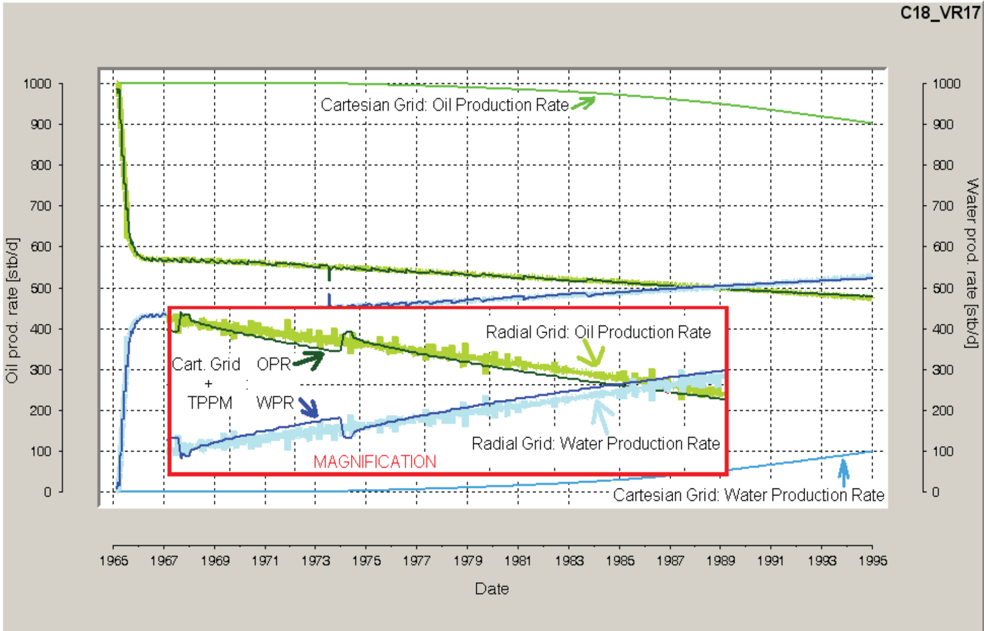

Figure 5.7: Comparison of "historical" Case C with Case A using TPPM.

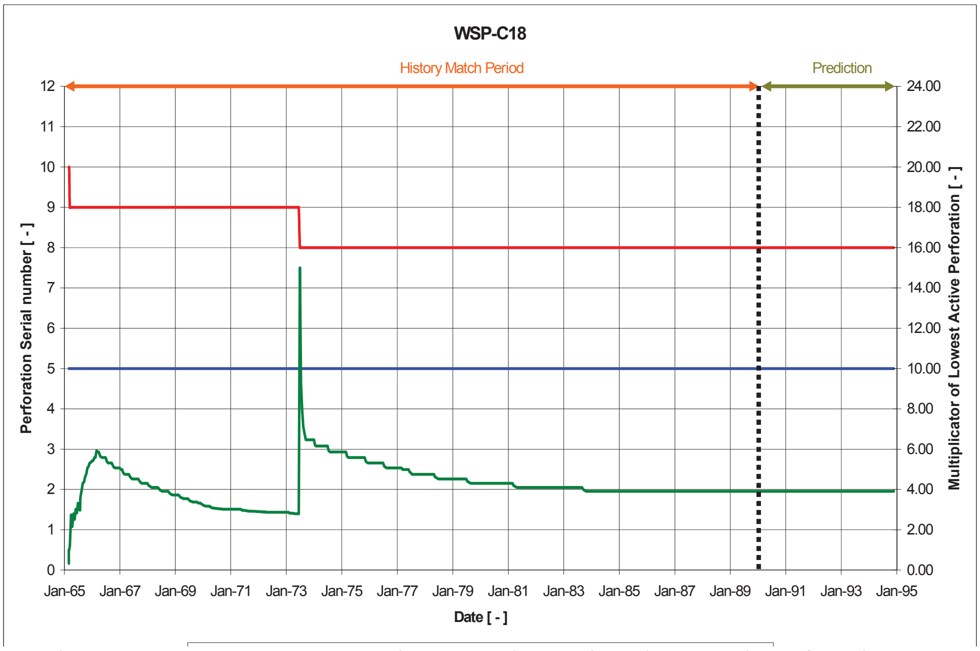

Figure 5.8: : WSP-C18 Active pseudo perforations and perforation transmissibility multiplier as a function of time.

5.4.2 Assessment of the Analytical Aquifer

Run_01 was performed using the 3-phase rate option. In this case the model well produces exactly the historical oil and water rate. Using the Target Pressure Method the water inflow was calculated, and at the end of the run the optimal aquifer parameters were determined.

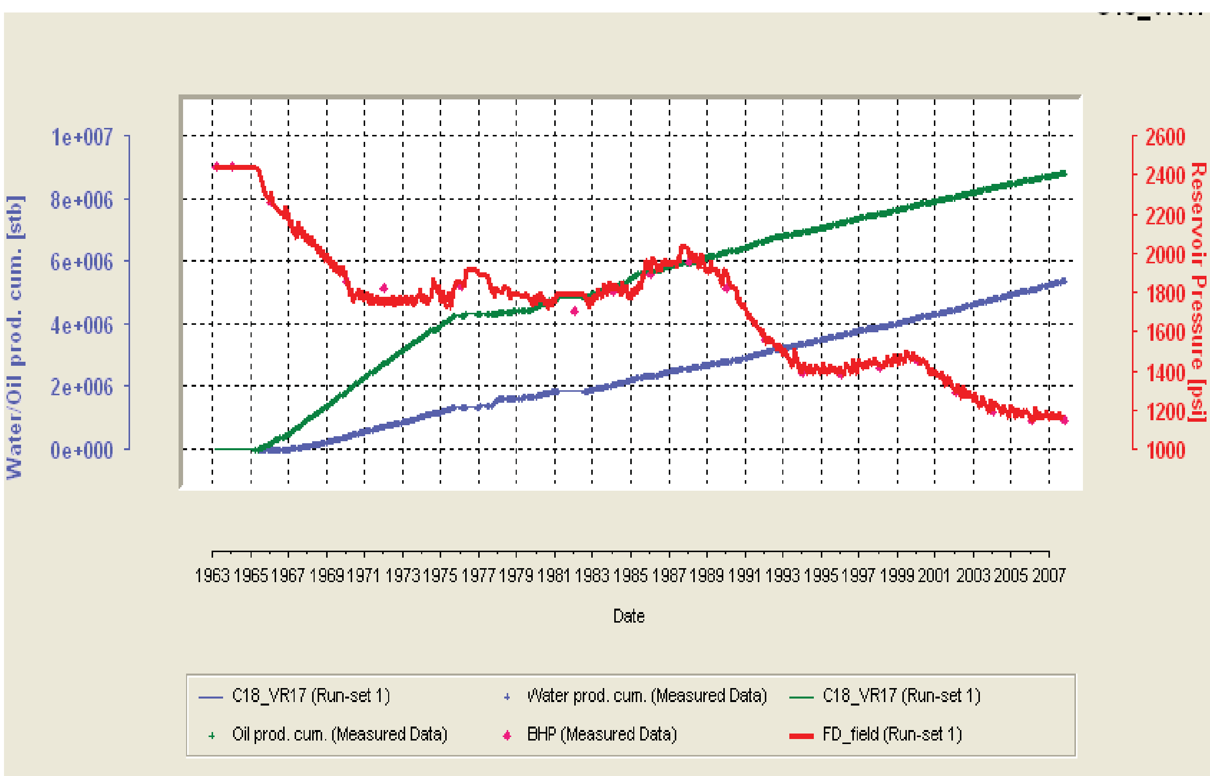

Figure 5.9: Run_01, pressure and cumulative oil and water production for the model C18W, operation with TPM.

Figure 5.10 shows the water inflow and the calculated average pressure. As it can be seen the model reproduces the target pressure nearby exactly.

The optimal analytical aquifer model is a Fetkovich type one with the parameters:

Maximum encroachable water: 0.345952E+08 [bbl]
Aquifer productivity index: 0.492543E+01 [bbl/(psi /day)]

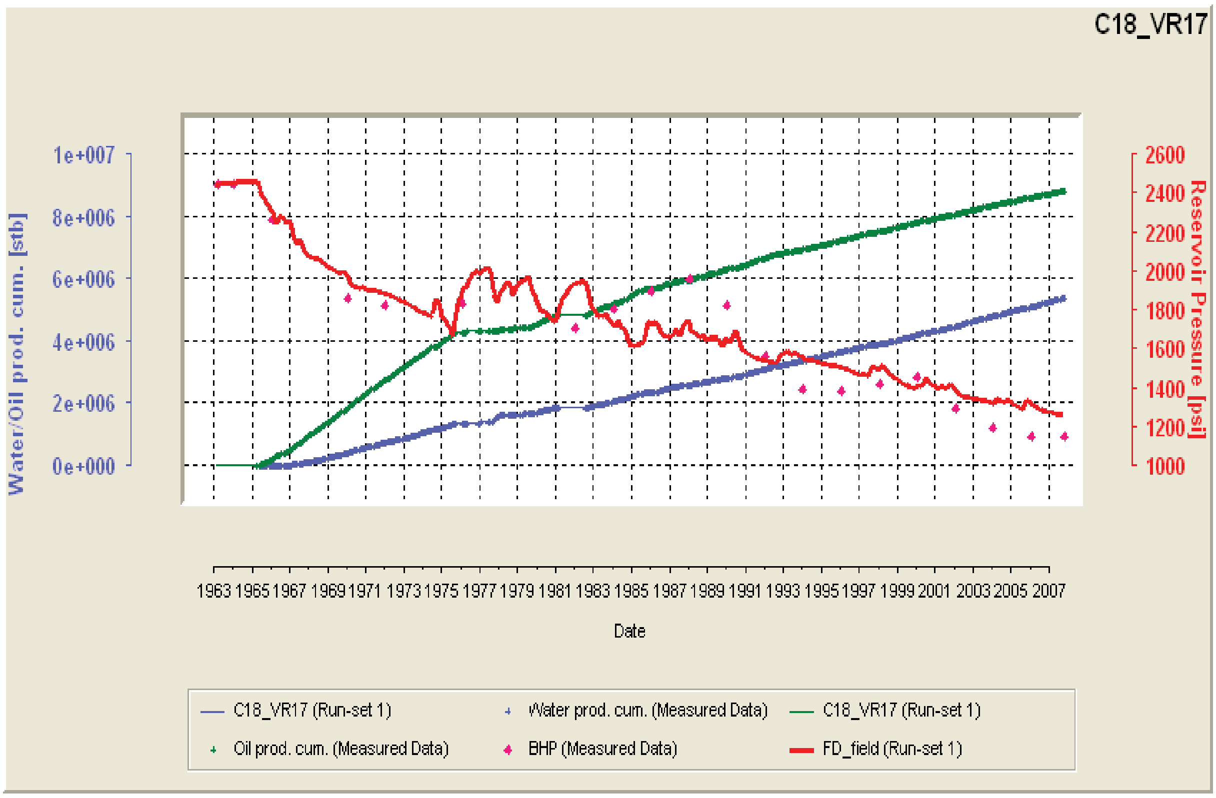

Figure 5.10: Run_02, result of C18W model operating with analytical aquifer.

The results of Run_01 and Run_02 show that the model is suitable for the planned investigations; the spot can produce the desired amount of oil and water under the given pressure history.

5.4.3 Experiments with Historical Production Rate

The exercise is now to match the production as closely as possible using the single well model. Note that all reservoir parameters, except the permeability, are equivalent to those in the geomodel. Naturally it would be advantageous to use the windowing technique, but this is not available in ECLIPSE. Therefore the Cartesian grid is the only real possibility. The match could be done as usual, i.e. the match could be performing by tuning some of the following parameters in the model:

- Horizontal permeability
- Vertical permeability
- Introducing layering, high and low permeability streaks
- Initial saturation distribution
- PI's for the perforations
- Relative permeability
- Capillary pressure

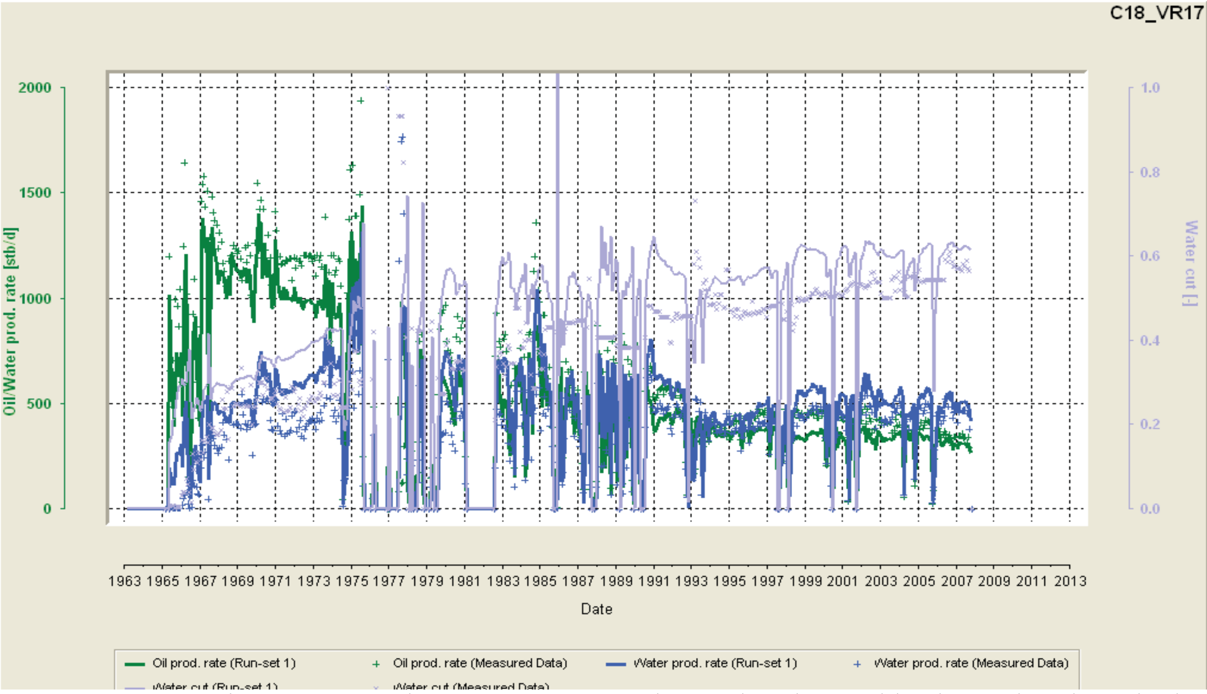

Figure 5.11: First attempt to match C18 by changed horizontal and vertical permeability

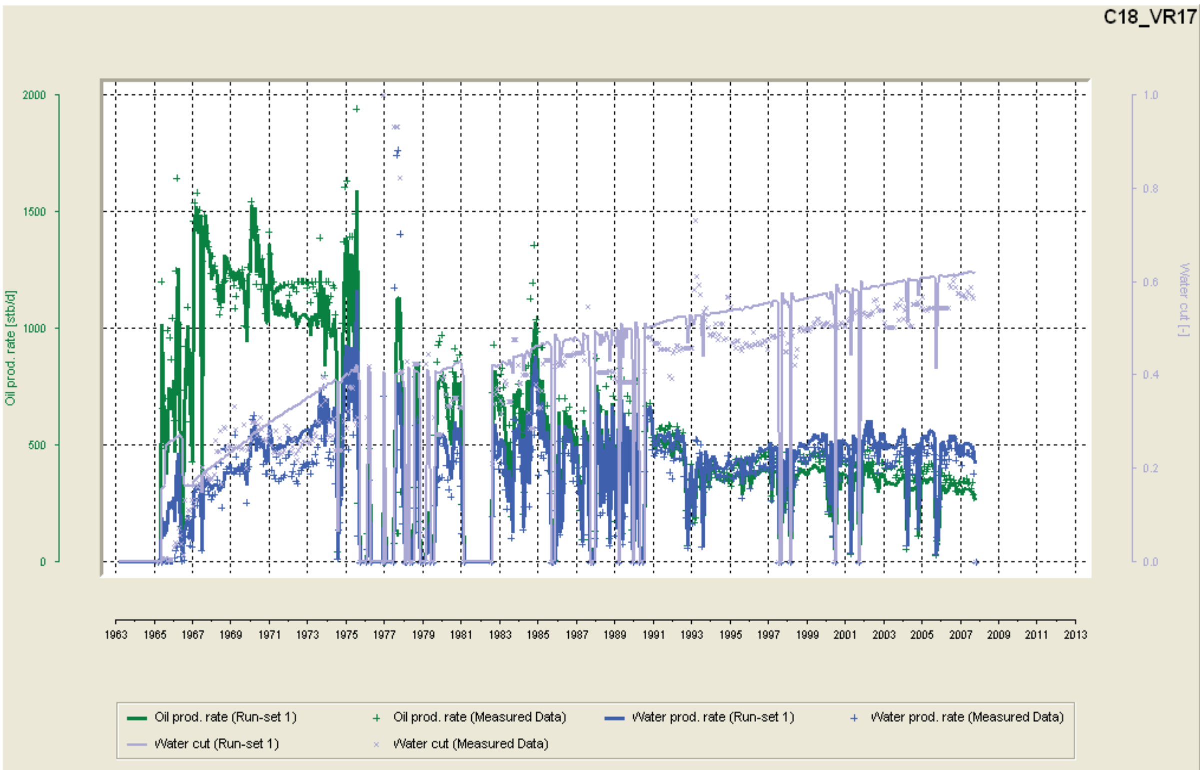

Figure 5.12: Tenth attempt to match C18 by changed horizontal and vertical permeability.

Figure 5.11 and Figure 5.12 show attempts to match the well by changing the horizontal and vertical permeability. Also if one or the other attempt would give better results, it cannot be known if the corresponding changes have something in common with the real reservoir. Nevertheless the results are poor in all of these cases. The surplus and shortage in the cumulative oil and water production makes the location of the remaining oil uncertain. The difference in WC tendency makes any production forecast questionable.

The production history tells two facts which are not disputable:

1. The production matches the amount of oil and water in the vicinity of the well.
2. The connection of the well to the phases and the inflow performances were exactly defined by the water cut.

Four points are disputable:

1. How far is the actual geological model from the reality?
2. Is the real reservoir-well connectivity equivalent with those in the model?
3. Are the assumptions of the reservoir physics (e.g.: relperm, wettability, etc.) and is their mathematical formulation correct?
4. Is the accuracy of the numerical solution (e.g.: gridding) satisfactory?

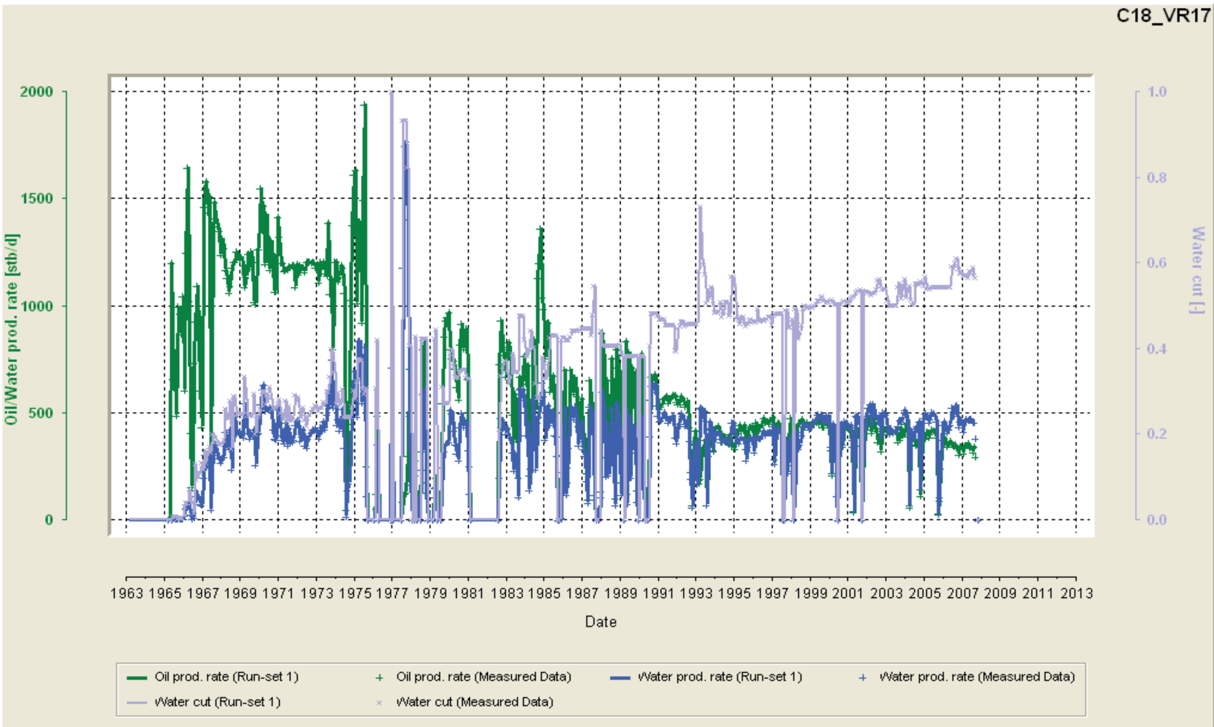

Figure 5.13: Result of history match using the automatic TPPM method.

What could be done?

Twist the reservoir and the physics or, admit that in certain cases the reservoir engineering science and practice is not able to say how the phases are distributed in the reservoir and how the well gets access to these.

It is better to let the well do, what it has to do and to accept, that the model failed to explain how it works.

Figure 5.13 shows the result of the match based on TPPM concept. The match cannot be better. As it can be seen, no such changes were allowed during the last 5 years, so the credibility of the forecast is assured. The possibility to optimize the well construction with this approach is not given.

The author believes that the water production in most of the CON55 wells is influenced by the combination of the following factors:

- extended transition zones,
- heterogeneous initial water saturation,
- fractional wettability,
- water coning,
- fractures and
- lateral water encroachment.

All these factors should be investigated further, to bring the analytical and the simulation models close to each other. The ideal situation in which a model satisfies both requirements will be never achieved.

5.5 Applicability of TPPM to Stratified Reservoirs

5.5.1 The Objective

Many different displacement patterns and processes can take place within a reservoir. The actual recovery processes can be regarded as a superposition of many individual processes happening at the same place concurrently. The aim of the full scale reservoir simulation model is to reproduce this complex recovery process. Just one example will be mentioned here. For volume region VR_17 water encroachment takes place concurrently from the North and from the East. Thus the individual North-South and East-West displacements are blurred out. Consequently a full scale model is not suitable for investigating and demonstrating the individual recovery processes. For such detailed studies specialized models like column, single well and cross section models are required.

Previously it was pointed out, that from the hydrodynamic point of view no distinct zonation for the CON55 Reservoir could be established. To be more precise, the zones G1-G7 identified during the creation of the 3D reservoir model based on lithostratigraphic well correlations did not indicate any vertical flow barriers or high permeability streaks. Nevertheless, such features cannot be excluded for CON55 Reservoir. Contrary, due to the complex water cut history of CON55 wells it is likely that such features exist, even if they could not be detected on well logs or seismic data.

Despite the likeliness and production data induced indications for the existence of vertical flow restrictions and/or high permeable channels, no information about their latter and vertical position and extent is available. Consequently it is not possible to introduce such features in the full scale simulation model.

Nevertheless the presented history match was able to reproduce the complex measured water cut history very accurately. The applied methodology was presented in Chapter 3.

The author conducted model calculations on a cross section model extracted from CON55 full scale model to demonstrate the impact of vertical flow restrictions and high permeable streaks on the displacement process. This Section and its Subsections will describe these model calculations in detail.

5.5.2 Model Setup

To demonstrate the displacement process in case of the existence of vertical flow restrictions and high permeable streaks a cross section model along the wells C18, C19 and C51, which are all situated in a row in West to East direction was extracted from the full scale model. A 3D view of this cross section model can be found in Figure 4.11 duplicated in this chapter by Figure 5.14. The coloring is chosen to show the initial water saturation distribution. Additionally the location (red blocks) of an outer boundary, acting as source for water influx from an outer analytical aquifer is shown. Despite the 3D character of the model displayed in Figure 5.14 it can be regarded as a cross section and not as a sector model, due to the fact that the displacement takes place only in two and not in three dimensions. The presented model calculations could be also conducted on a strict 2D cross section model, but in this case major alterations compared to the full scale model would have been necessary to operate the model in the desired way. For a 2D model the amount of original oil in place would be definitely too small to let produce the wells C18, C19 and C51 at their historical liquid rates. The author's goal was to keep the overall setup of the cross section model as close as possible to the full scale model. Only a limited number of minor alterations was introduced to enhance the effects that should be demonstrated with this type of model.

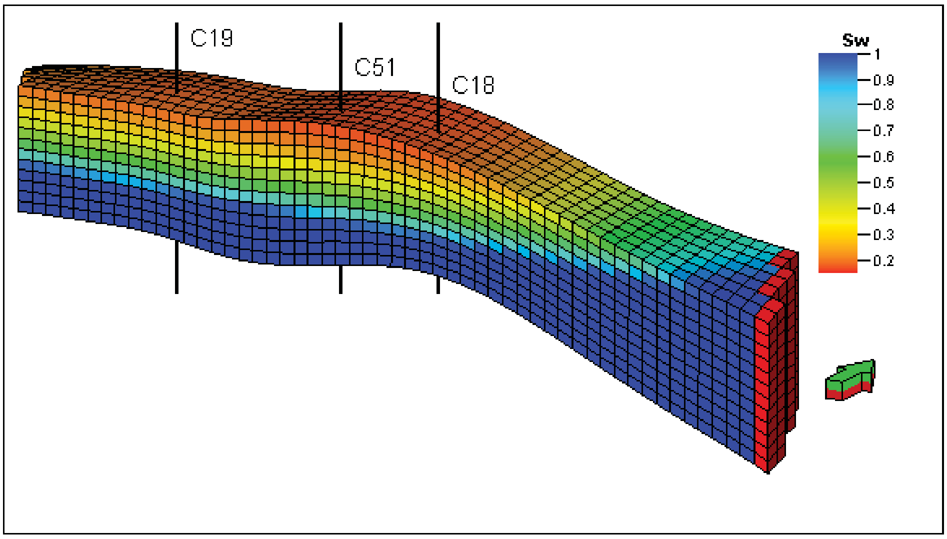

Figure 5.14: 3D view of cross section model showing wells C18, C19 and C51, initial water saturation distribution and location of water influx boundary (red blocks).

The cross section model in use is characterized by the following issues:

- Top and bottom structure, as well as the layering are exactly those of the full scale simulation model.
- The wells are at their real positions, produce their historic liquid rates and the completions of wells C19 and C51 are identical in position and time sequence to the real ones.
- Contrary to wells C19 and C51 the completion interval for well C18 was not changed over time for the model calculations. For demonstration purposes well C18 was completed in the second and third simulation layer only. The real perforation would be situated in the third and forth layer.
- Porosity and net-to-gross ratio was not altered compared to the full scale model.
- The lateral permeability equals 250 mD throughout the entire cross section model. Only for the third simulation layer the lateral permeability was increased by one magnitude.

The resulting transmissibility distribution in x-direction is shown in Figure 5.15. Despite the constant lateral permeability and the nearly invariable cell height, variations in transmissibility can be observed from Figure 5.15. These variations are solely the consequence of the stochastic net-to-gross ratio distribution. The artificially introduced high permeability streak can be identified by the sequence of red blocks.

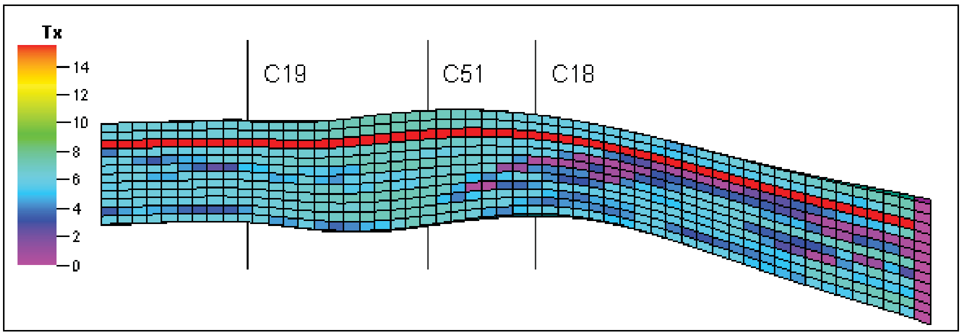

Figure 5.15: Cross section along wells C18, C19 and C51 showing lateral transmissibility distribution .

The vertical permeability equals 2.5 mD throughout the entire cross section model. Between the third and the fourth layer a vertical flow restriction was introduced by decreasing the transmissibility in z-direction by two magnitudes across this cell interface. This is indicated by the purple blocks in the third layer of Figure 5.16.

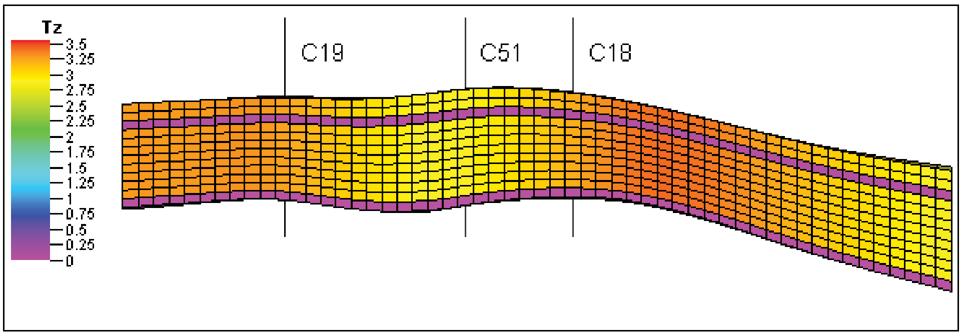

Figure 5.16: Cross section along wells C18, C19 and C51 showing vertical transmissibility distribution .

The chosen cross section is delineated by sealing faults at the West and at the East side in the full scale model. For the cross section model calculations this sealing character was kept for the West edge, but not for the East. Towards the East a boundary acting as interface for an outer analytical aquifer was attached. The location of this boundary is indicated by the red blocks in Figure 5.14. To achieve a closure towards this boundary, the free water level was set to 5248 ft SSL instead of the 5268 ft SSL of the full scale model. PVT and SCAL data equals those of the full scale model. The entire cross section model belongs to the first rock region.

The model described in Section 0 consists of 4548 blocks. The original oil in place equals 40.7 MMstb and the initial water volume equals 66.7 MMstb. The initial pressure was calculated to be 2446 psia. The model was operated for the entire history period of CON55 reservoir. All three wells were able to produce their historic liquid rates but the oil and water rates were naturally different.

One of the objectives of the **Case_I** was to demonstrate how the displacement would behave in the presence of a clear vertical flow restriction, respectively lateral high permeability streak. Both features act in a similar manner. They allow the encroaching water to override the oil. This overriding and the resulting stratified saturation distribution could be clearly demonstrated by the conducted cross section model calculations. To enhance the significance of such a displacement process, both features, the vertical flow restriction and later high permeability streak were combined into a single model.

Figure 5.17 presents the results of these model calculations Case_I. It displays the water saturation distribution at five distinct time points. At the top the initial state is presented. Due to the flow conduit in the third layer, water encroaching from the analytical aquifer attached to the Eastern model boundary tends to override the oil. This tendency can be observed on the subsequent cross sections.

Wells C18 and C19 both started to produce in mid 1965. Already half a year later the overriding effect can be observed (second picture from top in Figure 5.17). The longer the displacement process takes place, the more pronounced the overriding effect becomes, until the layers at a distinct column location are equally flooded.

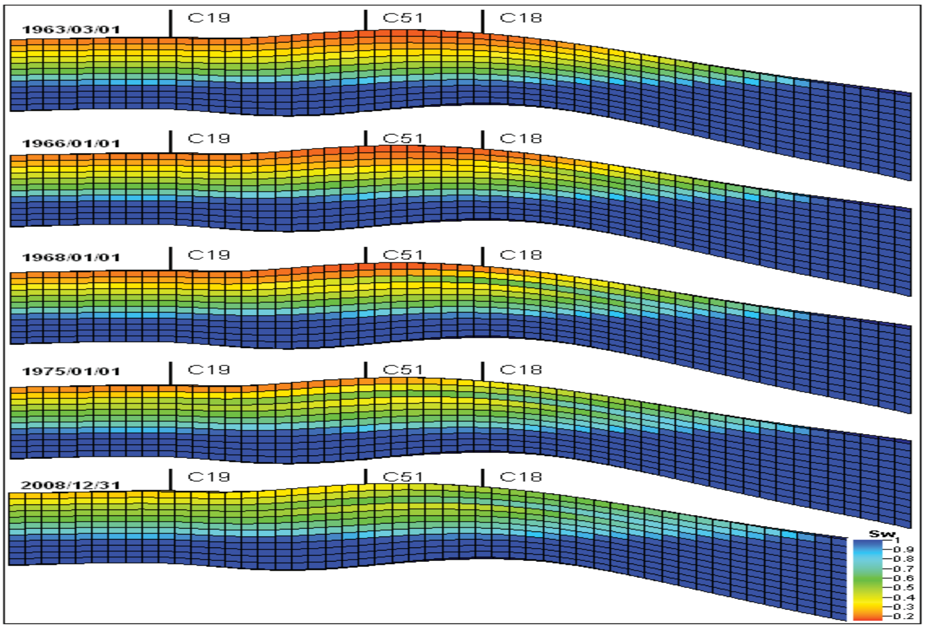

Figure 5.17: Water saturation distribution alterations for cross section model having a vertical flow restriction and a high permeability streak.

This model allows an experiment. The result should be regarded as “historical” and the reservoir parameters should be modified now in two directions:

1. **Case_II**: Influencing the phase distribution near the wells only: The high permeability streak and vertical barrier was taken out.
2. **Case_III**: Altering the phase distribution regionally: The permeability in the left upper side of the model (blocks I=1-56 from 106, K=1-6, from 12) was reduced by factor 10.

If the TPPM can provide what was promised, then in the first case it should be able to reproduce the history, in the second case not.

Figure 5.18 show the result of **Case_II**. The dots are the results of Case_I. As it can be seen, the two results are practically identical.

Figure 5.19 shows the result of **Case_III**. TPPM tried to do its best but a match was not achievable by using pseudo perforations and multipliers only. The model is still not matched globally.

In a situation as Case_II the modeler can switch to the "well_by_well" match, performing local parameter tuning. This cannot be done in Case_III. Also in Case_II it should be clear that not only the reservoir parameters are the question, but also the numerical methods in use. It can be easily seen, that with an improved discretization (orthogonal an unstructured PEBI grids, grid refinement, optimal layering) the pseudo perforations would be superficial.

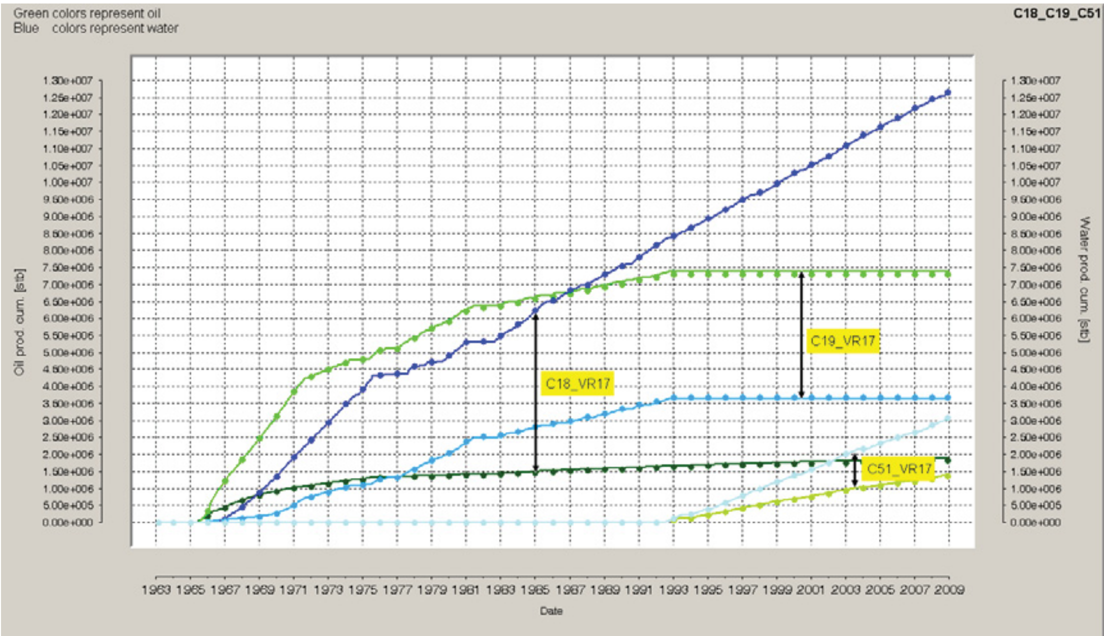

Figure 5.18: Cumulative oil and water production of the wells in Case_I (dots) and Case_II (continuous).

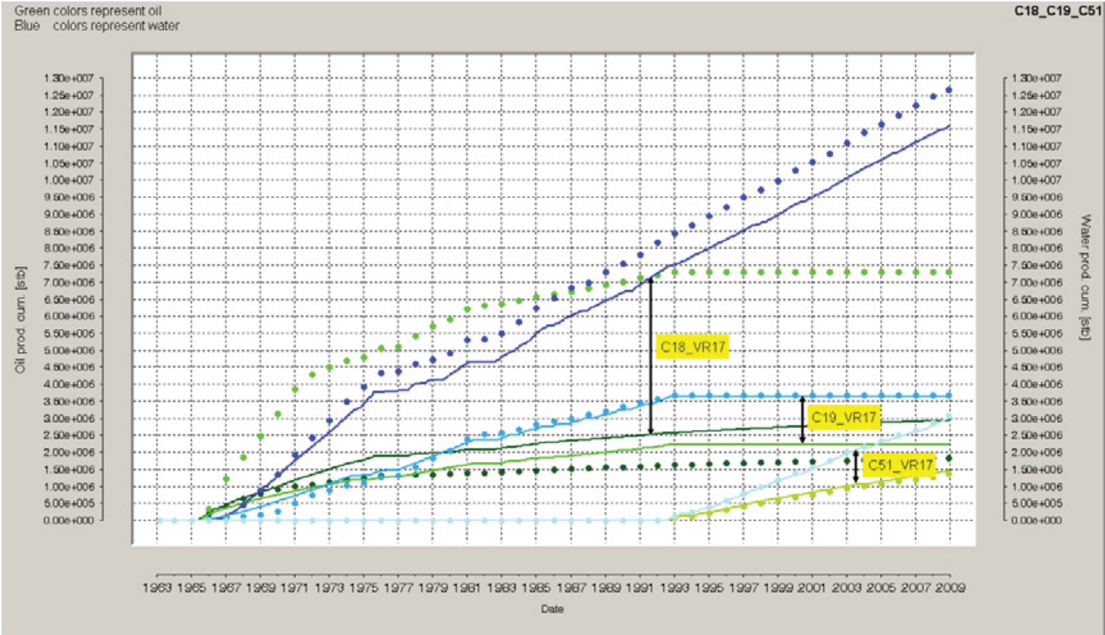

Figure 5.19: Cumulative oil and water production of the wells in Case_I (dots) and Case_III (continuous).

Chapter 6

Full Field Application of TPPM

6.1 Introduction

This chapter presents the first successful field application of TPPM. The project was conducted by HOL following a conventional History Matching approach and by using ECLIPSE simulation software. This was a fundamental obligation because the operating company requested the use of ECLIPSE^{TM} black oil simulator for this study but let open the possibility to apply also other tools under the condition that all of the finalized input data will be prepared as ECLIPSE input files and run on the Company's computers.

Most of the TPPM algorithms were developed while working on the full field model. The practice showed that after all small test examples worked fine, already 3 to 5 times more work was necessary to succeed with the real field example. Supplementary months were invested to generalize the code and to test it. The implementation of TPPM in PRS and the connected programing work was not done by the author, his merit and responsibility is limited to develop the concept and to the test the software.

The HM work needed 8 months in total (HOL worked on more projects in parallel). In half of the time ECLIPSE was used only. Later on PRS become the master tool. In the last cycle, after a final update of the geological model, only PRS was used until the end of HM. Then the PRS model was converted to ECLIPSE, making the predictions with it. It was not necessary to make any fine tuning on the PRS matched model, the results on ECLIPSE were practically identical.

In the following the field case will be presented in a “idealized” manner, as if the work flow would be applied from the beginning already. The goal is not to show the struggling during the development but to give an example for future applications.

6.2 History Matching Workflow

After setting up the first structural model, a 50x50 m areal grid with 84 layers has been constructed and parameterized. The question was how many simulation layers will be necessary and optimal. The model showed strong heterogeneities but no lower or higher permeability strikes could be correlated between the wells. On top of that, no separation surfaces could be identified. Therefore it was decided to upscale the model to 12 proportional simulation layers.

The 12 layer model with 137.400 active grid blocks was used for the conceptual modelling and for the history matching. The area was divided into 9 volume regions: VR1, VR2, VR3, VR4, VR17, VR7, VR8, VR9, and VR12 as shown in Figure 4.2. The well names were extended by the corresponding region names for easier orientation during the work (e.g.: C8_VR9 is a well in region 9). Boundaries were defined connecting the reservoir to outer aquifers. From the initially assumed 11 aquifer connections, 6 were proved to be active. They are Bound1, Bound3, Bound4, Bound6, Bound8 and Bound9.

It is always necessary to define a priori under which conditions the HM can be regarded as successful and applicable for forecasting. The results of a HM are the average pressures, static and dynamic BHP for wells, the cumulative oil, water and gas production and the production rates at the end of the history period. Which items are more important in a given case depends on the nature of reservoir, the depletion mechanisms and - very strongly - on the objective of the study. These limits are case dependent. It depends on the availability and quality of the data, on the quality of the geomodel and on the time frame of the study. The limits defined for the actual study are given in Table 6.1 and Table 6.2. The allowed difference in cumulative production on field and volume region level is given in absolute numbers (+/- MMstb) and also in percentage (%).

The production started in December 1964 and the end of HM was August 2009. The history match was conducted in three steps.

Table 6.1: Error limits field production

○	○ +/- MMstb	○ %
Oil	3.0	2%
Water	5.0	3%
Liquid	1.0	0.50%

Table 6.2: Error limits for average pressures

○	○ field level	○ volume regions level
Maximum	150 psia	100 psia
At the end of history	100 psia	50 psia

Step 1: Conceptual modeling and global matching

The main goal of this step was to constrain the static model and to avoid realizations which at the end of the day contradict the production history. The TPPM was used with the target pressure (ptarget) and the pseudo well (ph3rat)options. The TPPM assessed the water influx by closely matching the historical regional pressures and the oil and water production by activating pseudo perforations. This approach operates 2 wells instead of one at every well location: one produces oil, the other one water and calculates two bottom hole pressures. 32 from the 47 wells could be operated with historical oil and water rate over the entire 45 year period in the first run already. Based on the hints resulting from the simulation work the following improvement could be done in the geomodel:

- The reservoir top was corrected in the surrounding of the wells C35, C45 and C46, but without changing the well tops itself, which were strictly honoured as hard data.
- The original assumption that the NTG ratio is 1.0 was dropped. The actual average is now 0.87.
- Sub-seismic faults were identified between the volume regions VR_12 and VR_9 and VR_8 and VR_9. The position and extent of the volume regions can be found in Figure 4.2.

At the end of this step all wells were operated with the historical oil and water rates. Note that at this stage the global match is finalized. The reservoir pressure is matched for all volume regions producing exactly the historical oil and water rates during the entire HM period. Also the general setup of the simulation model was fixed as shown in Figure 4.2. This map contains all important elements: Faults, boundaries, regions and wells. The calculations confirmed the assumption made in material balance calculations, that the best solution can be achieved using Fetkovich type aquifer models.

Step 2: Spot by spot matching

The TPPM was used with the options ptarget, ph3rat and wetrat. Wells which became closer to be matched, were switched automatically from ph3rat to wetrat. The option wetrat operates the wells in the usual manner, but opens pseudo perforations if necessary. At this stage only one bottom hole pressure, valid for both phases, is calculated. The TPPM assessed the water influx by matching closely the historical regional pressures and the water cut by introducing pseudo perforations and perforation transmissibility multipliers. In this history matching phase regional porosity and permeability multipliers were applied and a supplementary rock region was introduced.

Step 3: Well by well matching.

In this step the target pressure method was not applied anymore. The water inflow was calculated by analytical Fetkovich aquifer models, determined in Step 2. The wells were operated under wetrat and netrat production control. TPPM with the automatic tuning of well inflows was applied to less and less wells; at the end to none of them. Perforation transmissibilities and near well reservoir properties were tuned in the usual - manual - way to match the well production histories as close as possible. In some wells the perforation intervals were still stretched or shortened to counterbalance grid effects (e.g.: coning) or not identified geological objects or properties (e.g.: interbedding). The procedure ended up in a conventional dynamic reservoir model, running also on ECLIPSE, were none of the TPPM options exist.

6.3 Initialization

There were two possibilities to initialize the simulation grid model:

- Non-equilibrium initialization on the basis of the saturation distribution from stochastic simulation.
- Equilibrium initialization based on capillary function, which can be different in every rock region.

The author and HOL's experts tried both possibilities, but then decided to go for the second solution. Figure 6.1 shows the two functions applied. The first one (green) was constructed from the log derived saturation distribution in the geomodel and tuned to become close to its OOIP. The second one (red) is an artefact and it was introduced during the history match to place more oil in certain regions. These regions are displayed in Figure 6.3.

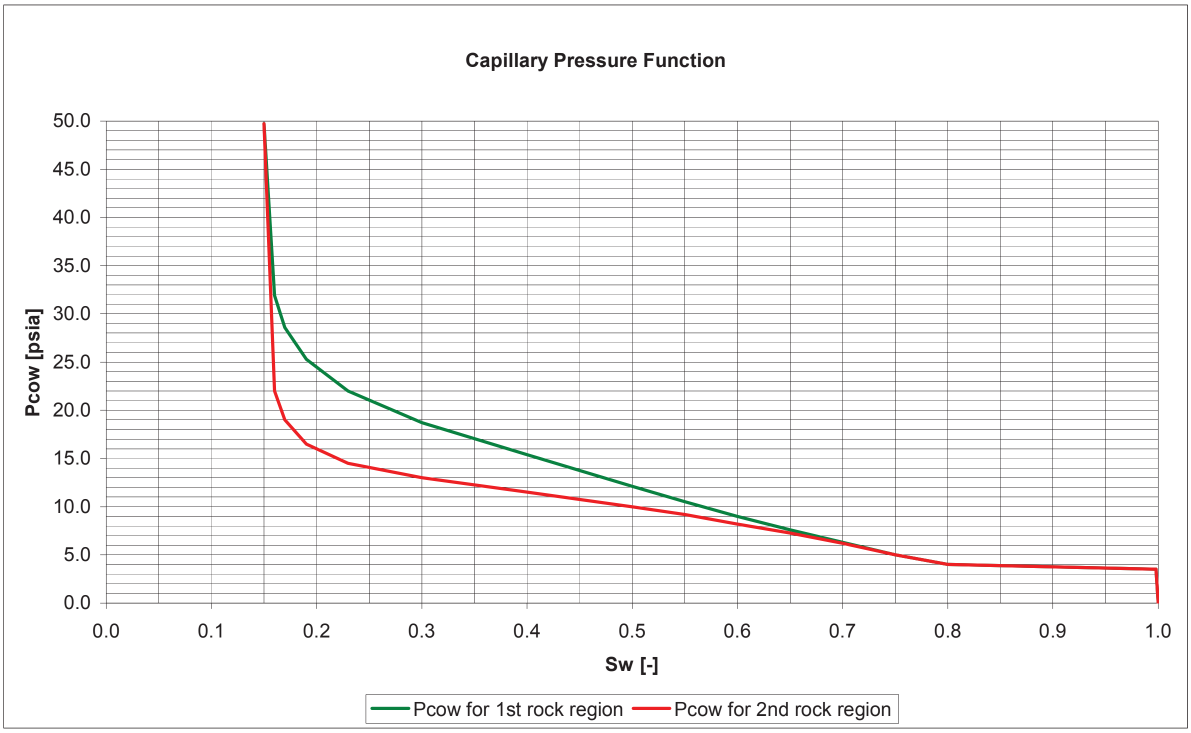

Figure 6.1: Capillary pressure as a function of water saturation.

The difference between the PA geomodel and the original simulation model, caused by the different initialization methods, was 0.3 % only.. The geomodels were initialized based on the stochastic water saturation distribution and the simulation models were initialized based on the capillary pressure functions.

As already written above, the geomodel was updated during the HM Step 1 already. All corrections were made by reinterpretation of seismic and log data and not by simple tuning. Further changes were made in the simulation model to enhance the HM. This section describes such kind of structural and parameter changes. Their geological relevance would be proven at the end of the modelling work and integrated into the final geomodel whenever possible.

6.3.1 Structural Modifications

The original structure of the geological model was updated solely in three areas of the CON55 reservoir. History matching showed that the amount of OOIP in the vicinity of well C35, C45 and C46 was insufficient to be able to produce the historically measured cumulative oil production from the simulation model. The objective of these structural changes was to lift the top structure within the uncertainty range inherent to seismic interpretation without altering the well tops of the wells itself.

6.3.1.1 Faults

Based on the observations and conclusions drawn from the simulation model, it was determined which faults or fault segments are sealing, partial sealing or open.

- Flt_N2, Flt_N3 are entirely outside of the area covered by the simulation model therefore their influence on the flow was not assessed.
- Flt_N1, Flt_N5, Flt_N6, Flt_S2, Flt_S3 were proven as sealing.
- Flt_N4 has shown to be partially sealing.
- Flt_N7 did not show to have any sealing character.
- Flt_N9 and Flt_N10 were considered as sealing.
- Flt_N8 is sealing where it separates VR_10 against its neighboring regions and has partly sealing character where it separates VR_11 against VR_12.
- Faults Flt_NS8 and Flt_NS12 are not part of the current geomodel, but have been identified in previous stages of seismic interpretation. Observations based on the dynamic simulation model indicated the existence of these faults, at least as baffles decreasing the communication between VR_8 and VR_12. Consequently, they have been considered in the simulation grid; even though no throw exists across them.

The positions of all these mentioned faults can be seen from Figure 4.2.

6.3.1.2 Aquifer Parameters

Parallel to the revision of the geomodel, the aquifer boundaries were defined and the water influx calculated. The following boundaries were identified as active: Bound1, Bound3, Bound4, Bound6, Bound8, Bound9.

During HM Step 2 the analytical aquifer parameters were assessed by using the Target Pressure Method. The calculation was repeated after every change of the reservoir parameters. The boundaries, the corresponding volume regions and the aquifer parameters are given in Table 6.3. This table contains the cumulative water inflow at 2008/12/31, too.

Table 6.3: Fetkovich analytical aquifer parameters and results

○ Boundary	○ Target VR	○ Wei	○ Jw	○ Cum. water inflow
○	○	○ [stb]	○ [psi/(bbl*d)]	○ [MMstb]
Bound1	VR_12	3.68E+12	59.20	80.49
Bound3	VR_7, VR_17	1.23E+10	128.00	81.68
Bound4	VR_5	1.28E+14	7.22	58.40
Bound6	VR_2	4.44E+10	82.40	8.23
Bound8	VR_3	1.28E+14	2.63	8.30
Bound9	VR_4	6.99E+10	0.129	20.14
			Sum	257,25

6.3.1.3 Porosity Alterations of the HM model

Besides the three local structural alterations mentioned above, the pore volume was corrected locally for a limited number of locations in the simulation model. The areal extent of these changes can be found in Figure 6.2. Some of these changes increased the pore volume; some of them reduced the pore volume. Due to the close relationship of the geological and the simulation model in HOL's workflow it is planned to shift these pore volume alterations towards the geological model for the final history matched model.

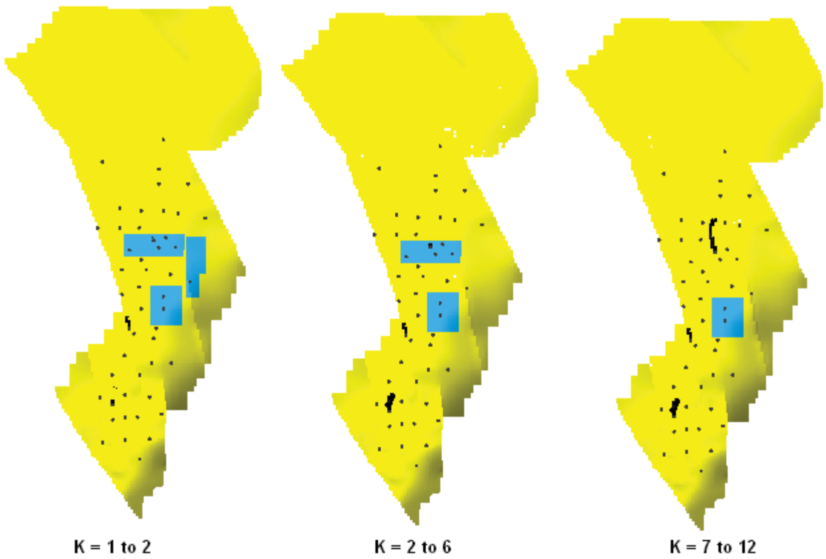

Figure 6.2: Porosity alterations in HM model (yellow - no change, blue - changed, dots - wells).

6.3.1.4 NTG Alterations in the HM model

During the history match the net-to-gross ratio was not changed, with one single exception. This exception regards one single simulation cell. This cell is intersected by the trajectory, to be more precise by the completion interval, of well C48. The original upscaled NTG value of the respective cell was close to zero, leading to a very low productivity index of the resulting grid-well connection. Consequently, the well could not produce the desired rates. To solve this problem the NTG of this cell was set to a value of the cells in its vicinity.

6.3.1.5 Rock region distribution in the HM model

Two rock regions were used during history matching. The majority of the reservoir is modelled with the first rock region indicated in blue in Figure 6.3. The second rock region corresponds to the orange area. In vertical direction a stack of simulation cells has the same rock region. The rock regions differ only in the applied capillary pressure function. These functions have been shown in Figure 6.1 as a capillary pressure versus water saturation plot.

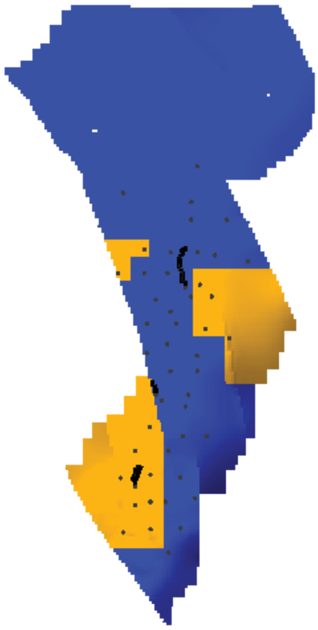

Figure 6.3: Rock region distribution HM model (blue corresponds to 1st and orange to 2nd rock region).

6.3.1.6 Permeability Alterations in the HM model

To achieve a well by well history match the permeability distribution was changed on two levels:

- Regional changes e.g.: on volume region level
- Local changes in the vicinity of the individual wells.

In Figure 6.4 the extent of the lateral permeability changes is indicated and in Figure 6.5 the vertical ones. Areas with altered permeability are indicated in blue. Please note that these plots do not indicate if the permeability was increased or decreased.

Aim of all these permeability changes was to tune the calculated water cut of the wells, to match the historical ones. For matching the water cut, local permeability tuning was introduced laterally and vertically. Prior to tuning the WC some wells required an enhancement of lateral permeability to prevent a shut in of the well due to minimum bottom hole pressure constraints.

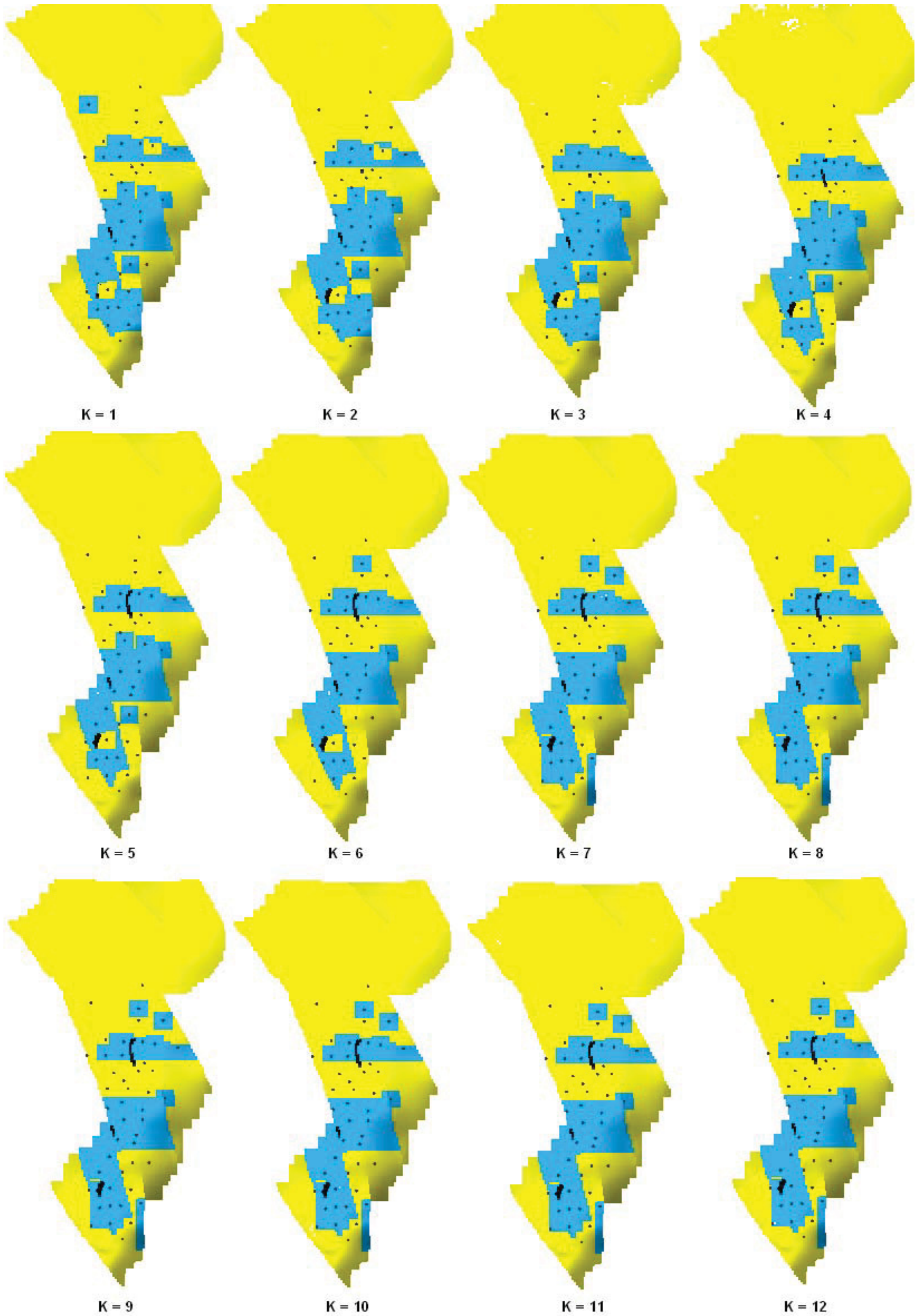

Figure 6.4: Lateral permeability alterations in HM model (yellow - no change, blue - changed, dots - wells).

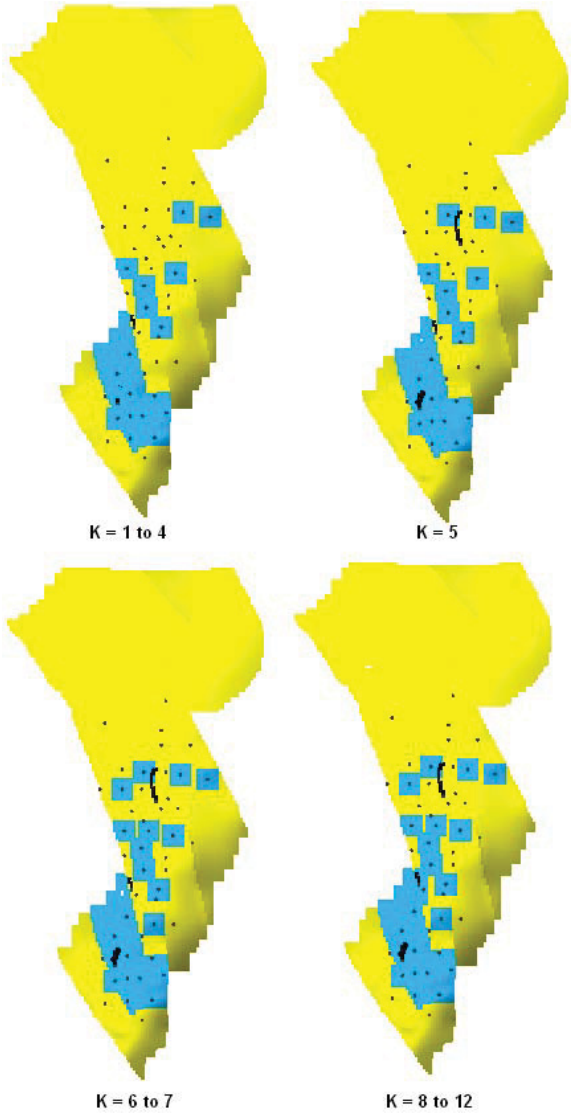

Figure 6.5: Vertical permeability alterations in HM model (yellow - no change, blue - changed, dots - wells).

6.4 Results of the History Match

The following tables and plots summarize the state of the history matching efforts up to the author's involvement (23 March 2009).

6.4.1 Global Match

Figure 6.6 to Figure 6.8 show the pressure match for 3 regions connected directly to an analytical aquifer.

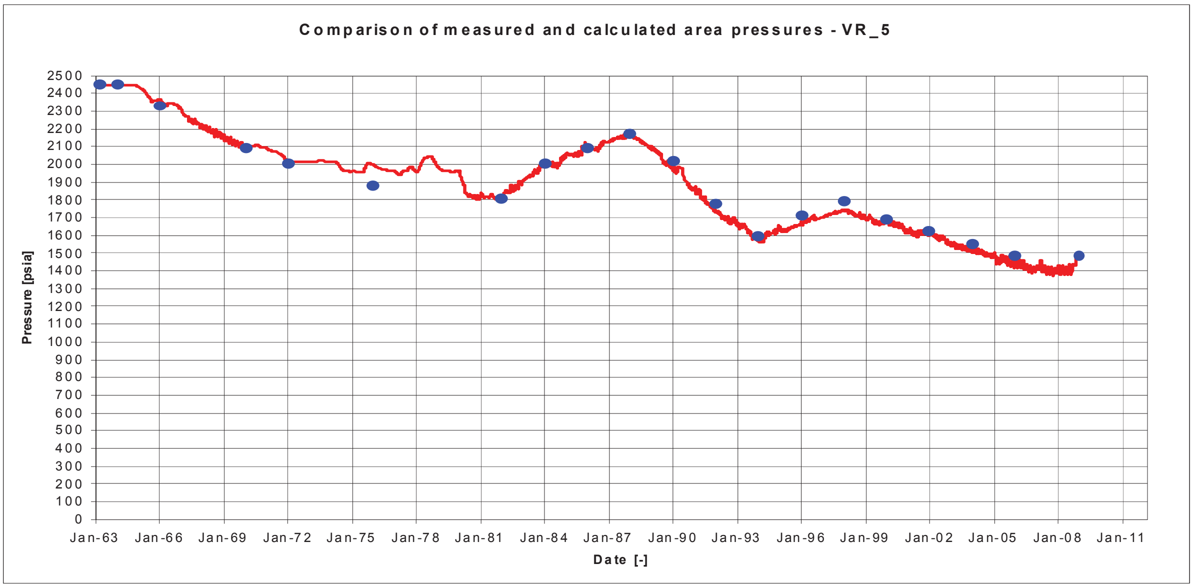

Figure 6.6: Comparison of measured and calculated area pressures - VR_5.

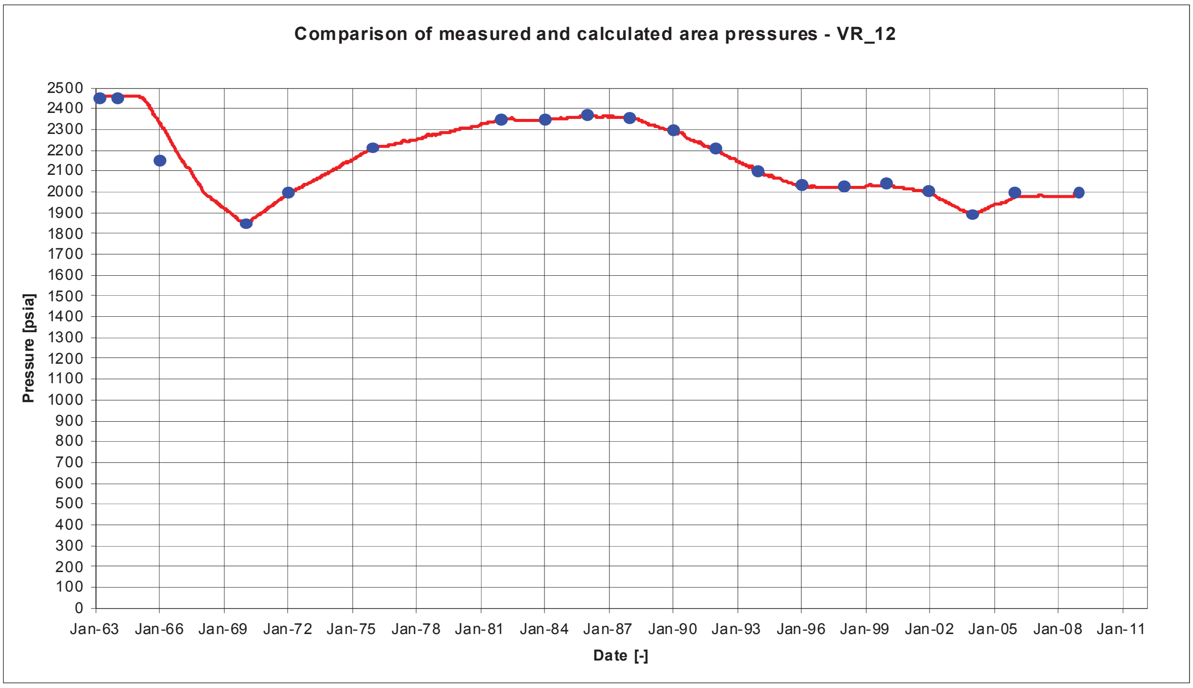

Figure 6.7: Comparison of measured and calculated area press. VR_12.

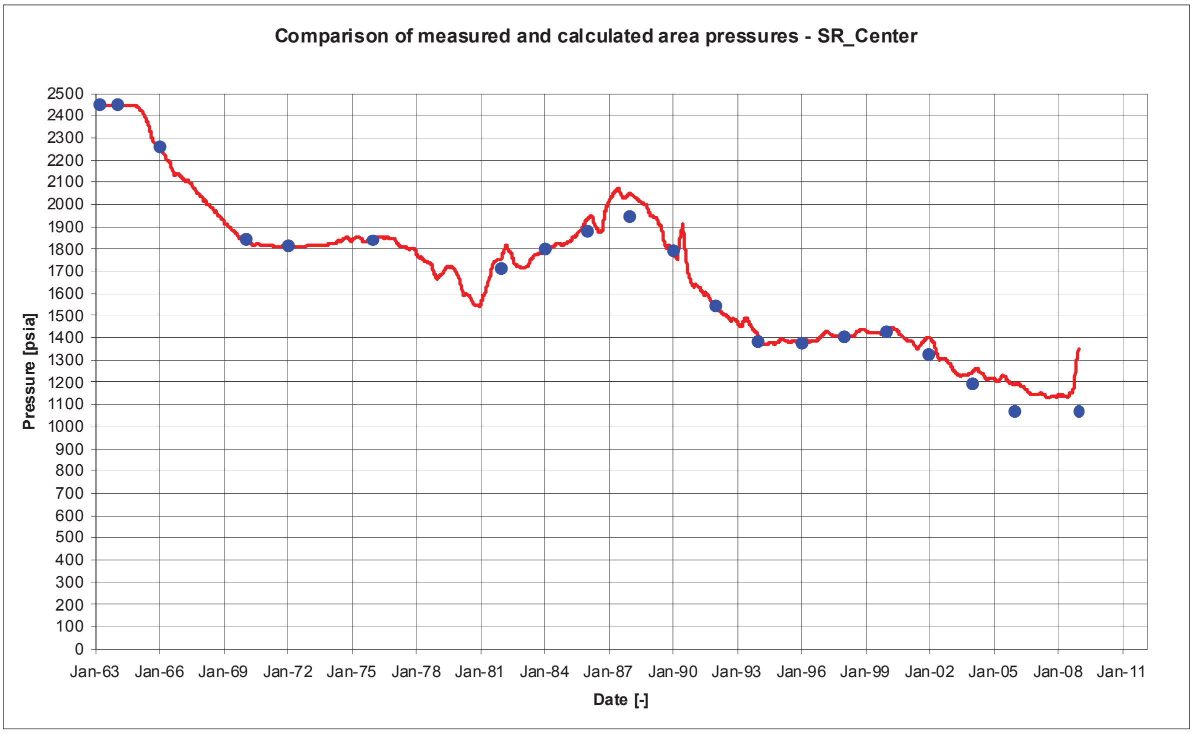

Figure 6.8: Comparison of measured and calculated area press. SR_Center.

6.4.2 Well-by-Well Match

The results of the history match are categorized in excellent, good, fair and failed. Some individual well plots are given in Appendix C based on ECLIPSE runs. The results were evaluated from two respects of the match: the cumulative oil production and the last year production rates. Regarding the oil rates the error % was calculated over the liquid rate (gross rate). Table 6.4 gives an overview about the quality of the well by well history match. It takes both, the cumulative production as well as the average rate in the last year, into account to classify the well by well history match. (Sorry, but the figures had to be cancelled.)

Table 6.4: Quality of the history match

Cumulative production				
○	○ Target	○ Matched	○ Diff.	○ %
Oil [MMstb]				2.51
Gas [MMscf]				-2,71
Water [MMstb]				-3.86
Avr. Pressure [psia]	1510	1576	66	4.19

Average production rate in 2008				
○	○ Target	○ Matched	○ Diff.	○ %
Oil stb/day]				14.0
Water stb/day]				2.0

6.4.3 Saturation distribution in the Reservoir

This Section shortly deals with the initial and the resulting saturation distributions at the end of the history match in the CON55 Reservoir (main block only). The figures in this Section consist of three different parts. At the top the initial conditions are shown. The middle picture shows the calculated ECLISPE saturation distribution at the end of year 2008. At the bottom the respective PRS results are shown. A total of three figures is shown here. Figure 6.9 presents a 3D view of the model area. Figure 6.10 is part of a cross section in South-North direction and Figure 6.11 is part of a cross section in West-East direction.

From all three figures the water encroachment, originating from the analytical aquifer models of the boundaries can be clearly seen. Especially in Figure 6.11 the displacement of oil by water flowing from the East towards the West can be clearly identified. Figure 6.10 on the other hand shows occurrence of a rise of the local water table in the vicinities of the wells. This is indicated by the bumpy water saturation in the transition zone.

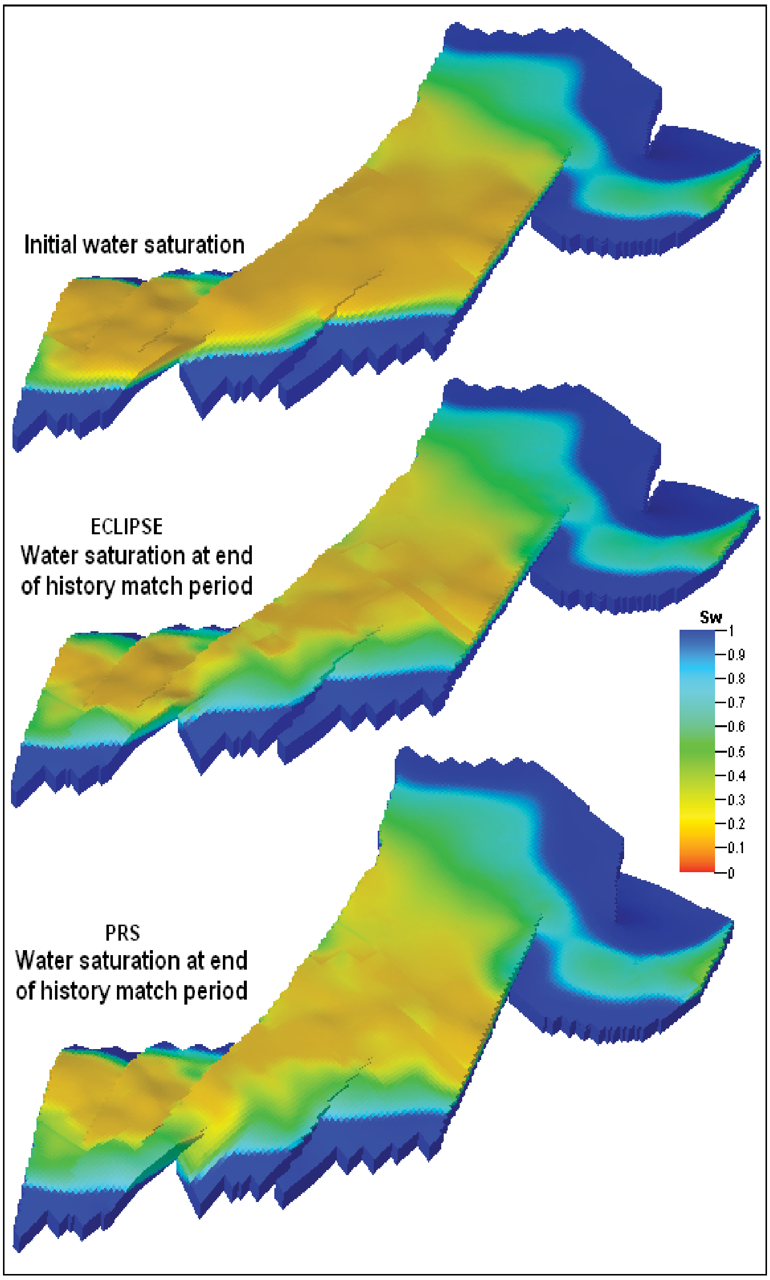

Figure 6.9: 3D view of CON55 Field showing initial water saturation and at end of history match period .

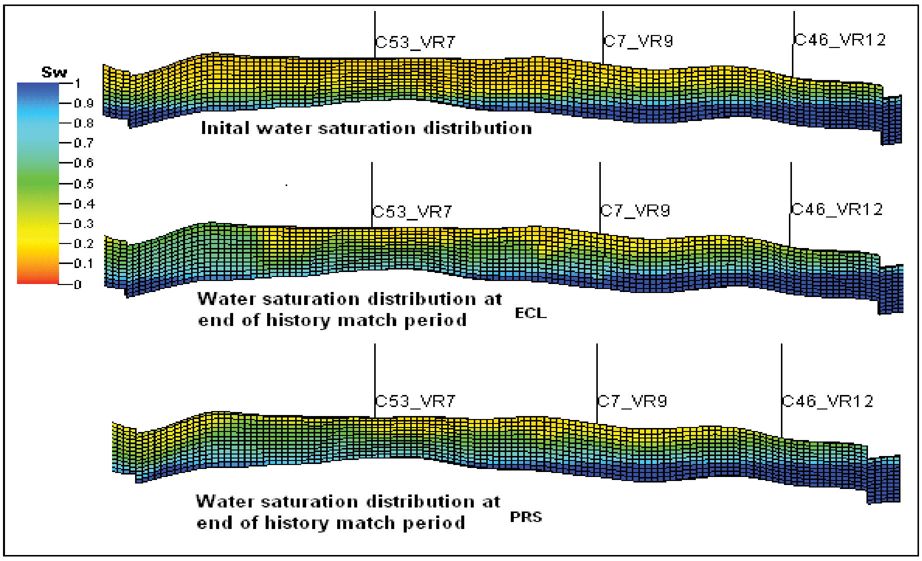

Figure 6.10: Cross section along wells C53, C7 and C46 showing initial water saturation and at end of history match period .

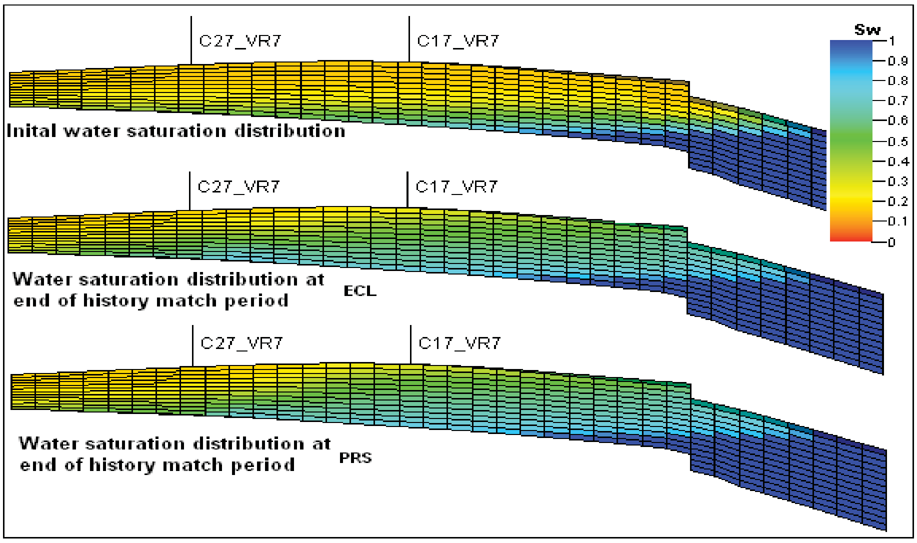

Figure 6.11: Cross section along wells C27 and C17 showing initial water saturation and at end of history match period.

Chapter 7

Closing Remarks

The author strongly believes that the objectives formulated in Chapter 1 were fully achieved. The original idea was proved as workable and the TPPM workflow could be established and improved step by step. The code became robust with the time and generally usable. The method was already applied to the fields

1. Maros, gas reservoir, UGS, Hungary, operated by E'ON, 2008.
2. AHM, oil field, Libya, operated by Akakus, 2009
3. North Gialo and Farigh, oil field, operated by WAHA
4. Libba, oil field, operated by Harouge, 2009.

The last three fields together have an OOIP of over 30 Bstb. The author sees an enormous potential to apply TPPM in Libya. Most of the reservoirs contain undersaturated oil and are depleted by bottom water drive, similar to the example field.

TPPM was developed in PRS but it could be easily implemented in any other simulation software, especially in ECLIPSE. Such a step would help to make it available for the entire petroleum producing industry.

It is sure that there is a large potential for further developments. TPPM has a certain kind of artificial intelligence capability. TPPM fails if there is not enough oil, water and gas at a certain spot in the model at a given time to satisfy the historical target production. In such situations the simulator can estimate the reasons for the failure, and can suggest possible improvements in the geological model. Such developments were already initiated. PRS offers also some auxiliary methods as material balance and displacement calculation, decline curve analysis, well test capability, single well modeling, etc. which can be used in combination with TPPM.

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Chapter 9

Nomenclature

Symbols

A	-	area, cross section, [m²]
c_p	-	compressibility factor of phase p [1/bar]
c_t	-	total compressibility factor [1/bar]
c_ϕ	-	apparent pore compressibility factor [1/bar]
D_p	-	specific mole density, [kmol/m³]
D_{pc}	-	diffusion coefficient, [m²/s]
$\vec{g}$	-	gravity acceleration vector, [m/s²]
$\vec{J}_{pc}$	-	molar flux of component c in phase p, [kmol/m² s]
$\bar{k}$	-	permeability tensor
k	-	permeability, [m²]
k_{rp}	-	relative permeability, [-]
M_c	-	molar mass of component c, [kg/mol]
$\vec{n}$	-	normal unit vector
N	-	total number of grid cells
$OOIP$	-	original oil in place [m³]
p_p	-	phase pressure, [bar]
p_{target}	-	target pressure, [bar]
q_p	-	flow rate of phase p, [m³/s]
q_p	-	source/sink term for phase p, [kmol/day]
q_{cmf}	-	matrix-fracture transfer term, [kmol/day]
S_p	-	phase saturation, [-]

t	-	time [days]
T	-	temperature, [K]
$\vec{u}_p$	-	filtration velocity, [m/day]
V_I	-	Volume of gridblock I, [m²]
V_p	-	Pore volume, [m³]
V_ϕ	-	Pore volume, [m³]
V_{p1}	-	Volume of phase p produced during phase p' imbibition, [m³]
V_{p2}	-	Volume of phase p produced during phase p' flooding, [m³]
V_T	-	Bulk volume, [m³]
x_{pc}	-	mole fraction of component c in phase p, [-]
z	-	depth, [m]

Greek Symbols

ϕ	-	porosity, [-]
Φ_p	-	phase potential, [bar]
λ_p	-	phase mobility, [1/cp]
μ_p	-	phase viscosity, [cp]
ρ_p	-	phase density, [kg/m³]
τ_{IJ}	-	interblock transmissibility, [m³]
Δ_t	-	time difference operator, $\Delta_t\Gamma = \Gamma^{n+1} - \Gamma^n$
Γ	-	boundary

Subscripts

c	-	component
g	-	gas
i	-	initial conditions
i	-	shape factor class
i	-	point index
ir	-	irreducible
k	-	location on the recovery curve
$k+1$	-	location on the recovery curve

l	-	left
m	-	matrix
n	-	old time level
$n+1$	-	new time level
o	-	oil
p	-	phase
r	-	relative
r	-	residual
r	-	right
w	-	water
x,y,z	-	coordinate directions

Superscripts

N_c	-	total number of components
N_p	-	total number of phases
ν	-	old iteration level
$\nu+1$	-	new iteration level

Conversion Factors

bar	=	psia*0.06894757
m	=	ft*0.3048
kg	=	lb*0.453592
$1000m^3$	=	MMSCF*26.795
kg/m^3	=	lb/ft^3*16.01846
°F	=	°R-459.67
°C	=	$\frac{(°F-32)}{1.8}$
°API	=	$\frac{141.5}{\text{Spec. Gravity}-131.5}$

Appendix C

C.1 Results of Well by Well Matching for the Full Field Project

The full field example is described in Chapter 4 and Chapter 6. It is not possible to incorporate all results of the history matching in this work but this supplement should provide an insight into the amount of the study work and its excellent results. The Appendix C exists in two versions, this second one is the neutralized and reduced version.

Corresponding to the TPPM workflow the target rates for the wells would be defined as 3 phase rate, as wet rate and in the end phase as net oil rate. Therefore the oil rate is always correct equal to the historical values. The history matching can be qualified on the bases of the cumulative water production and the water rate and the water cut respectively. The classifications are excellent, good, fair and failed. The respective limits are given in the Table C.1

Table C.1: Limits applied to assess the quality of the history match

	%
Cum. oil production	1%
Cum. water production	5%
Cum. liquid production	5%
Difference in oil production rate at the end of HM:	1%
Difference in water production rate at end of HM:	10% excellent, 20% good, 50% acceptable, 50 bbl abs. excellent
Difference in water breakthrough time	less than 6 month
Max. difference in WC at the end of HM	5%
Static bottomhole pressure	none
Dynamic BHP	Not compared

- **Excellent**: if all differences are considerably under the limits;
- **Good**: The differences are below the limits;
- **Fair**: The differences are above the limit but the tendencies are similar. The simulation result gives the possibility of a quantitative estimation of future performance;
- Failed: The real and model wells behave differently.

The result of the history matching is summeriesd in Table C.2 to Table C.4. The Figure C.1 to Figure C.21show examples for the 4 categories.

C.1.1 Tabulated Results:

Table C.2: Full Field Example Summary of Well by Well Match Part1.

Well	VR	Production		Cum. Oil Prod.	Avg. Oil Prod. Rate End HM	Quality of match	Quality of match	Quality over all
		Start	End	Historical	Historical	Cum.	Rate	Both
[-]	[-]	[Date]	[Date]	[Mstb]	[stb/day]	[-]	[-]	[-]
C43	VR2	1982	1991	128	0	Good		Good
C44	VR2	1985	Act.	969	64	Good	Excell.	Good
C49	VR2	1985	1994	165	0	Fair		Fair
C36	VR3	1993	Act.	697	124.2	Excell.	Excell.	Excell.
C45	VR3	2003	Act.	524	263.5	Good	Good	Good
C33	VR4	1980	Act.	5560	131.3	Fair	Fair	Fair
C35	VR4	1985	2008	2157	0	Fair		Fair
C37	VR4	1985	Act.	5996	508.1	Excell.	Excell.	Excell.
C39	VR4	1981	2007	1542	0	Fair		Fair
C42	VR4	1982	Act.	1942	31.3	Excell.	Good	Good
C58H	VR4	2002	Act.	1275	344.5	Fair	Good	Fair
C34	VR4	1988	1989	17	0	Failed		Failed
C52	VR4	1992	Act.	4256	325.1	Good	Good	Good
C10	VR5	1965	1992	1675	0	Excell.		Excell.
C40	VR5	1987	1994	303	0	Excell.		Excell.
C32	VR5	1980	1999	4263	0	Good		Good
C38	VR5	1985	Act.	3894	194.8	Excell.	Excell.	Excell.
C62	VR6	2006	Act.	272	135.5	Good	Excell.	Good
C17	VR7	1965	1995	1572	0	Good		Good
C31	VR7	1979	Act.	14482	598.6	Good	Excell.	Good
C25	VR7	1978	Act.	5835	126.5	Excell.	Excell.	Excell.
C27	VR7	1978	Act.	6840	208.5	Excell.	Excell.	Excell.
C29	VR7	1978	1991	1028	0	Good		Good
C30	VR7	1979	Act.	5564	437	Excell.	Good	Good
C41	VR7	1982	Act.	1995	81	Good	Good	Good
C53	VR7	1982	Act.	1094	104.7	Excell.	Good	Excell.

Table C.3: Full Field Example Summary of Well by Well Match Part2.

Well	VR	Production		Cum. Oil Prod.	Avg. Oil Prod. Rate End HM	Quality of match	Quality of match	Quality over all
		Start	End	Historical	Historical	Cum.	Rate	Both
[-]	[-]	[Date]	[Date]	[Mstb]	[stb/day]	[-]	[-]	[-]
C19	VR17	1965	1992	9739	0	Excell.		Excell.
C24	VR17	1977	Act.	6809	415.2	Excell.	Excell.	Excell.
C26	VR17	1978	Act.	6788	333.2	Excell.	Excell.	Excell.
C28	VR17	1978	Act.	2756	149.3	Good	Good	Good
C18	VR17	1965	Act.	8986	141.7	Excell.	Excell.	Excell.
C51	VR17	1992	Act.	2903	365.9	Excell.	Excell.	Excell.
C56	VR17	1993	Act.	2788	407.1	Excell.	Excell.	Excell.
C57H	VR17	2001	Act.	2225	747.4	Good	Excell.	Good
C59H	VR7	2002	Act.	1589	531.3	Excell.	Excell.	Excell.
C6	VR17	1964	1991	12028	0	Excell.		Excell.
C22	VR8	1970	1977	233	0	Fair		Fair
C8	VR8	1964	Act.	11107	166.8	Excell.	Excell.	Excell.
C21	VR9	1970	Act.	5671	200.9	Good	Good	Good
C23	VR9	1977	2000	3369	0	Excell.		Excell.
C3	VR9	1965	1977	1019	0	Excell.		Excell.
C54	VR9	1993	Act.	2798	293.4	Excell.	Excell.	Excell.
C55	VR9	1993	Act.	1264	258.8	Good	Excell.	Good
C7	VR9	1964	1977	4382	0	Good		Good
C2	VR12	1965	1968	563	0	Excell.		Excell.
C16	VR12	1965	1972	184	0	Good		Good
C46	VR12	1986	Act.	661	78.7	Good	Excell.	Good
C48	VR12	1987	Act.	1928	148.8	Excell.	Excell.	Excell.
C50	VR12	1992	2009	822	13.7	Excell.	Excell.	Excell.
C66	VR12	2009	Act.	82	390	Fair	Failed	Failed

Table C.4: Summary of Full Field Example History Match Quality Classification on Well Basis

Full Field Example	History Match Quality Classification		
Classification	Category Cum. Production (50 wells total)	Category Rate End of HM (50 wells total)	Category Overall Quality (50 wells total)
Excellent	50%	69%	46%
Good	34%	28%	38%
Fair	14%	0%	12%
Failed	25%	3%	4%

C.1.2 Examples for Excellent HM:

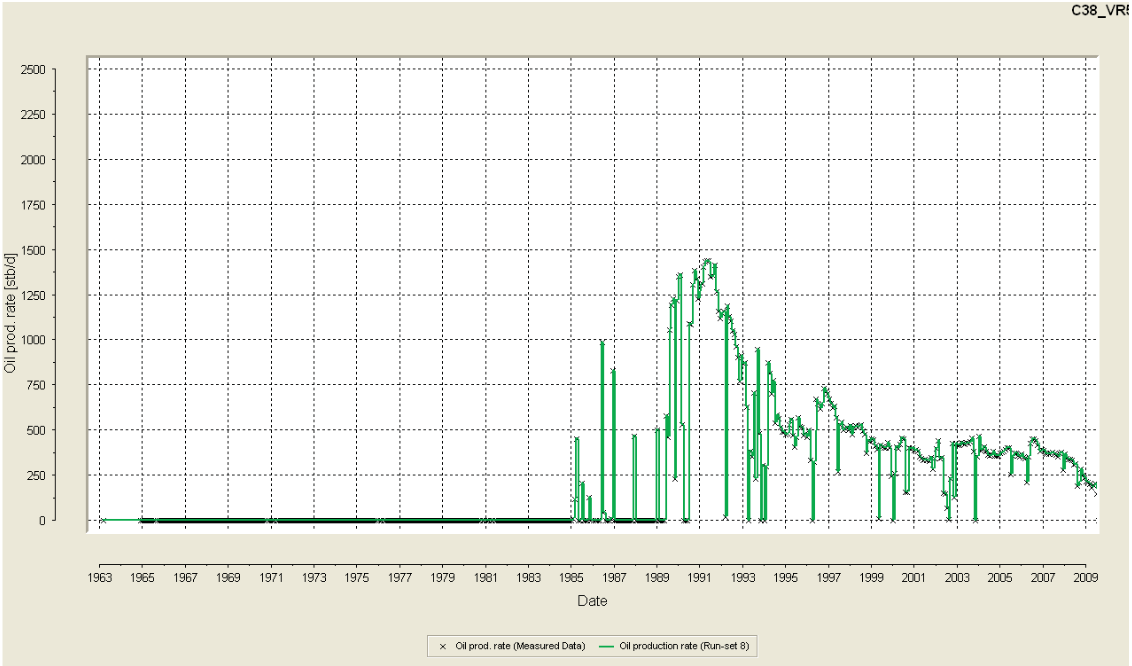

Figure C.1 C38_VR5 Oil rate in history matching period.

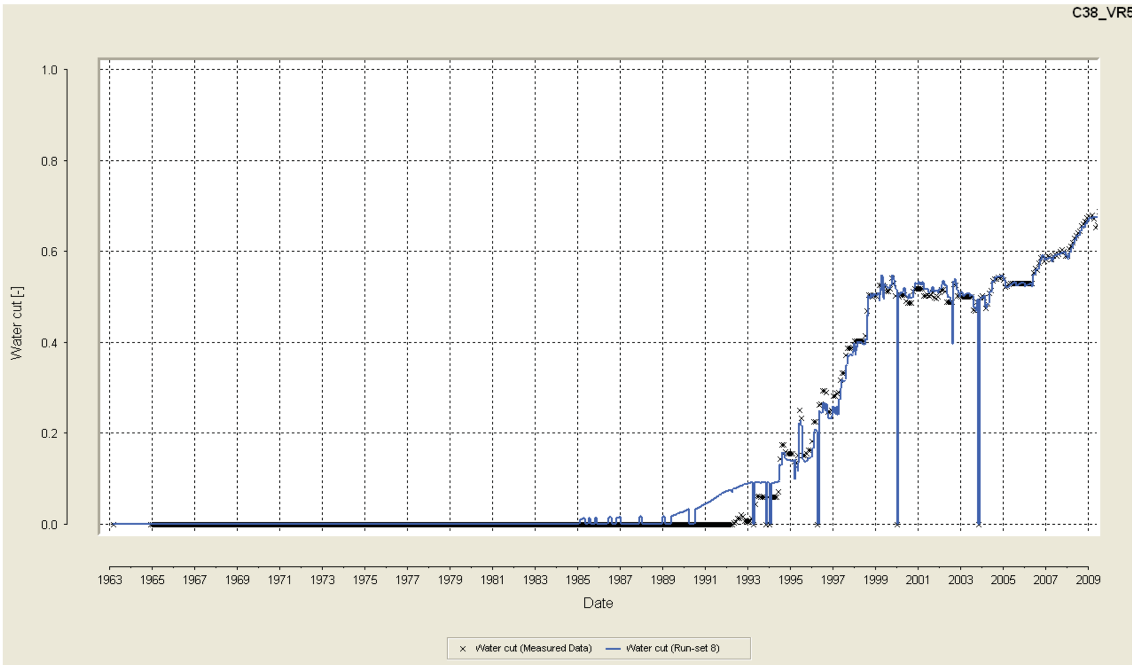

Figure C.2 C38_VR5 Water Cut

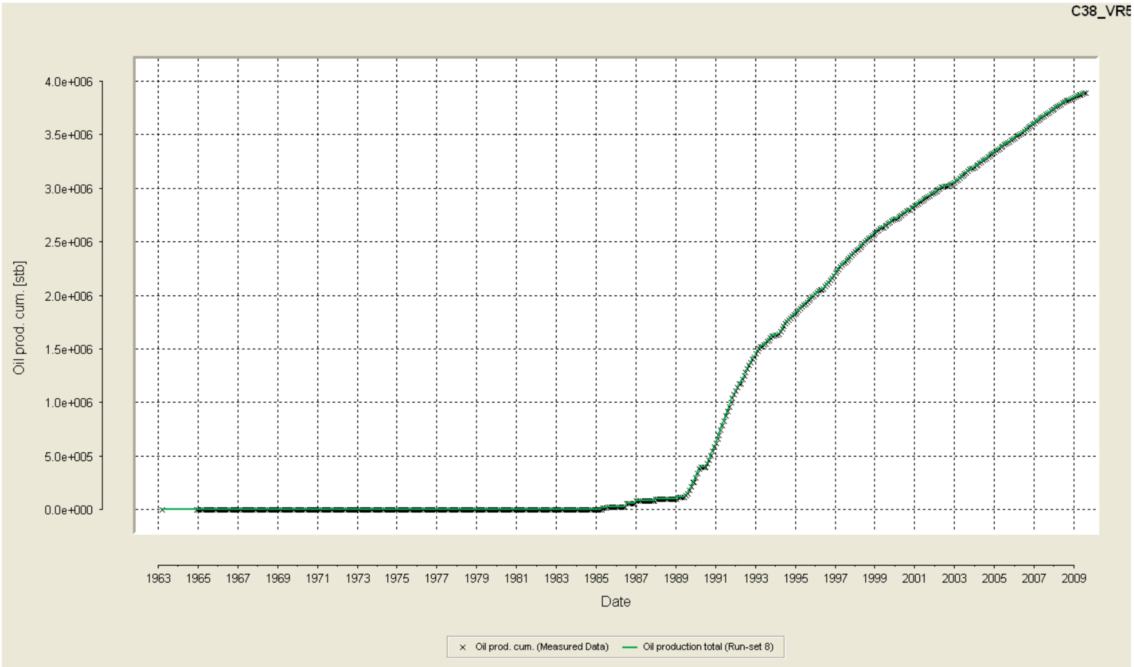

Figure C.3 C38_VR5 Cumulative oil production

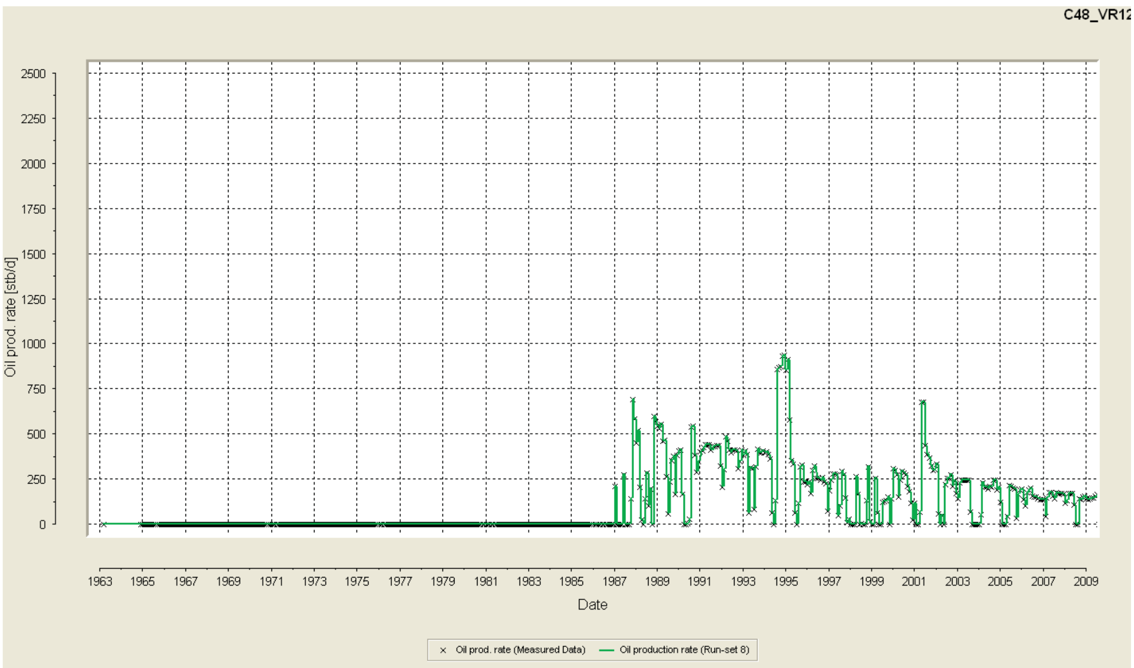

Figure C.4 C48_VR12 Oil rate in history matching period

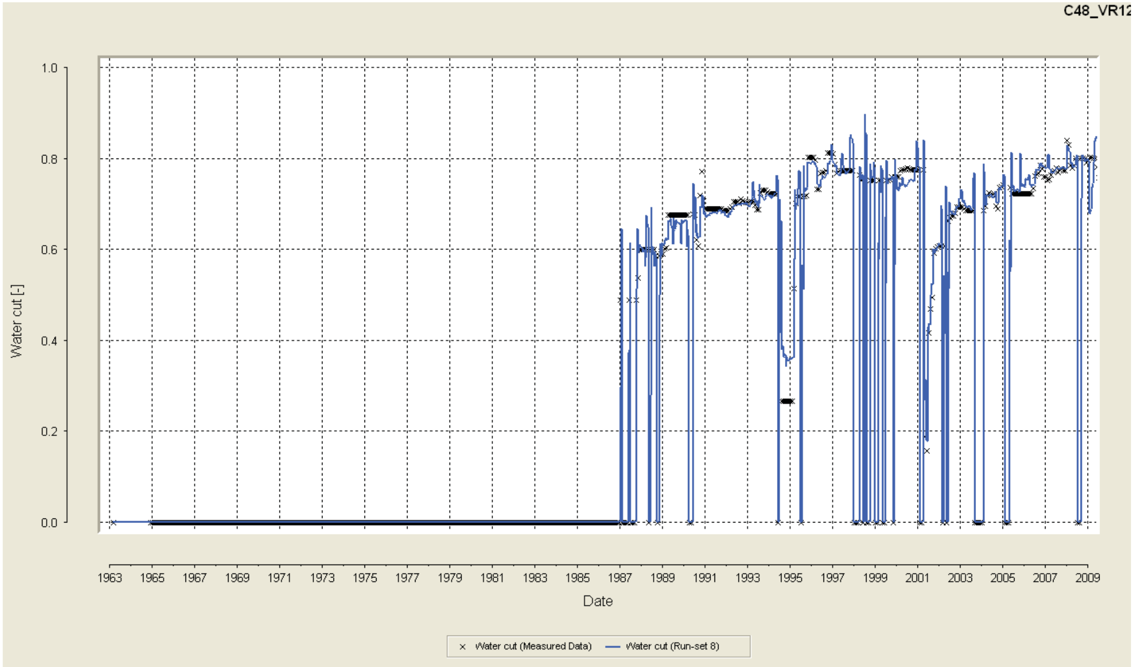

Figure C.5 C48_VR12 Water Cut

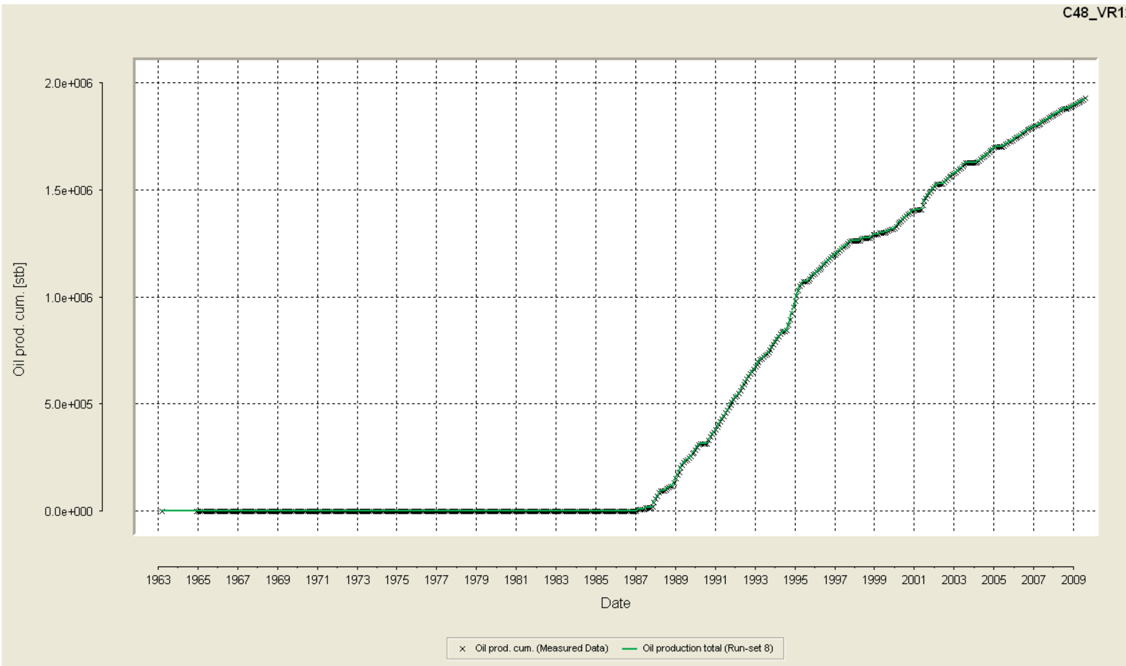

Figure C.6 C48_VR12 Cumulative oil production

C.1.3 Examples for Good HM:

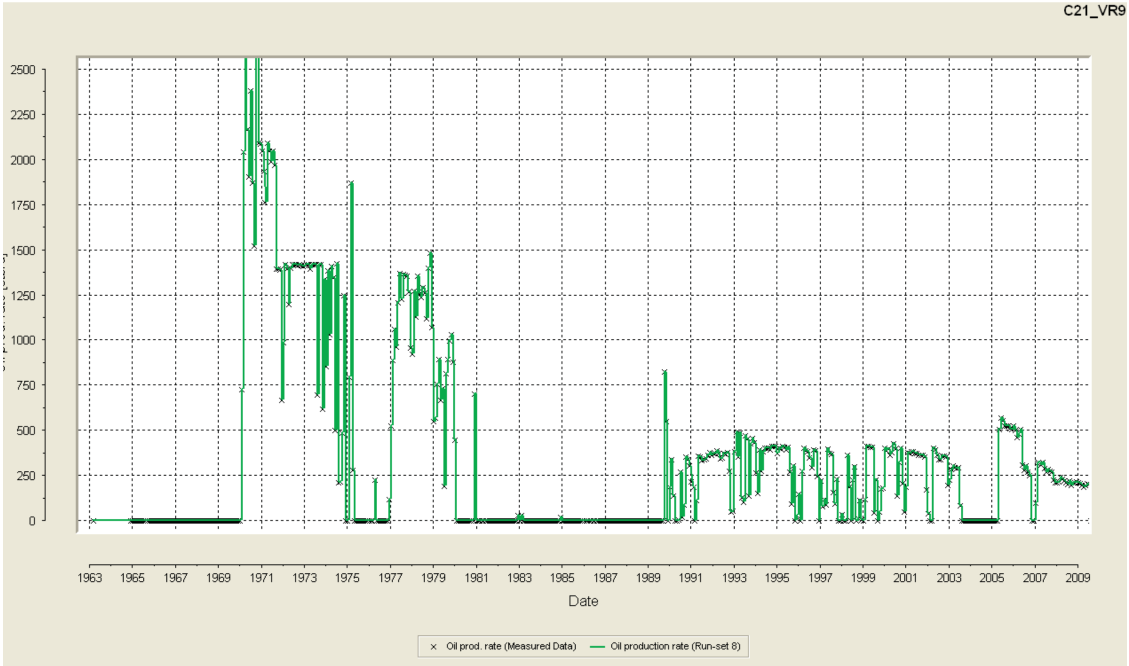

Figure C.7 C21_VR9 Oil rate in history matching period

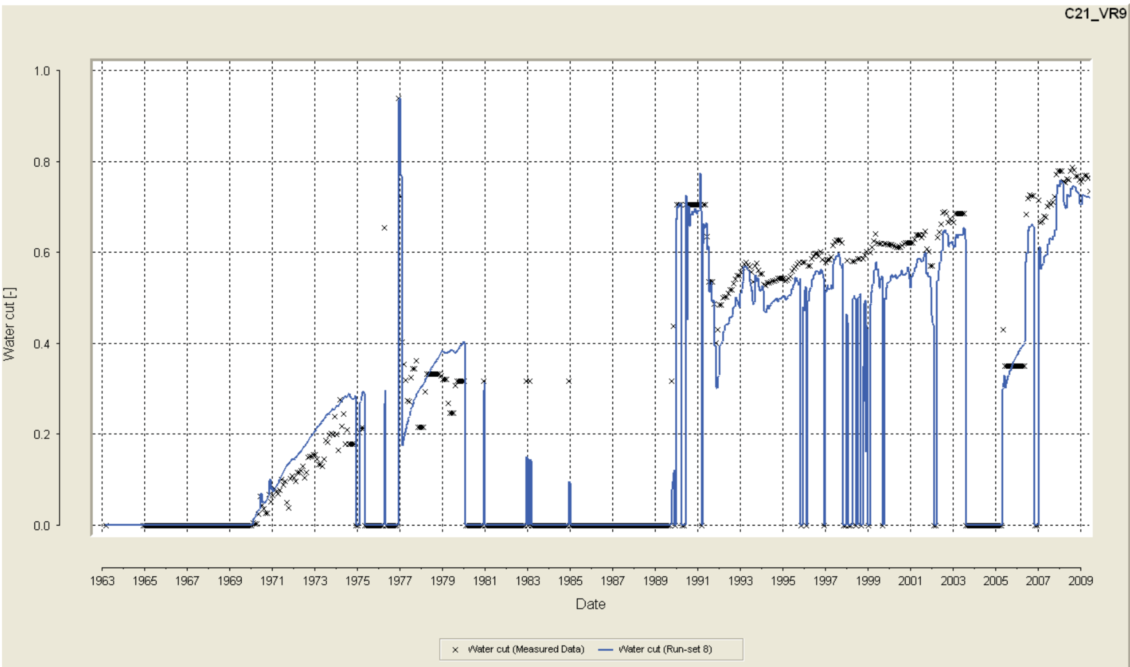

Figure C.8 C21_VR9 Water Cut

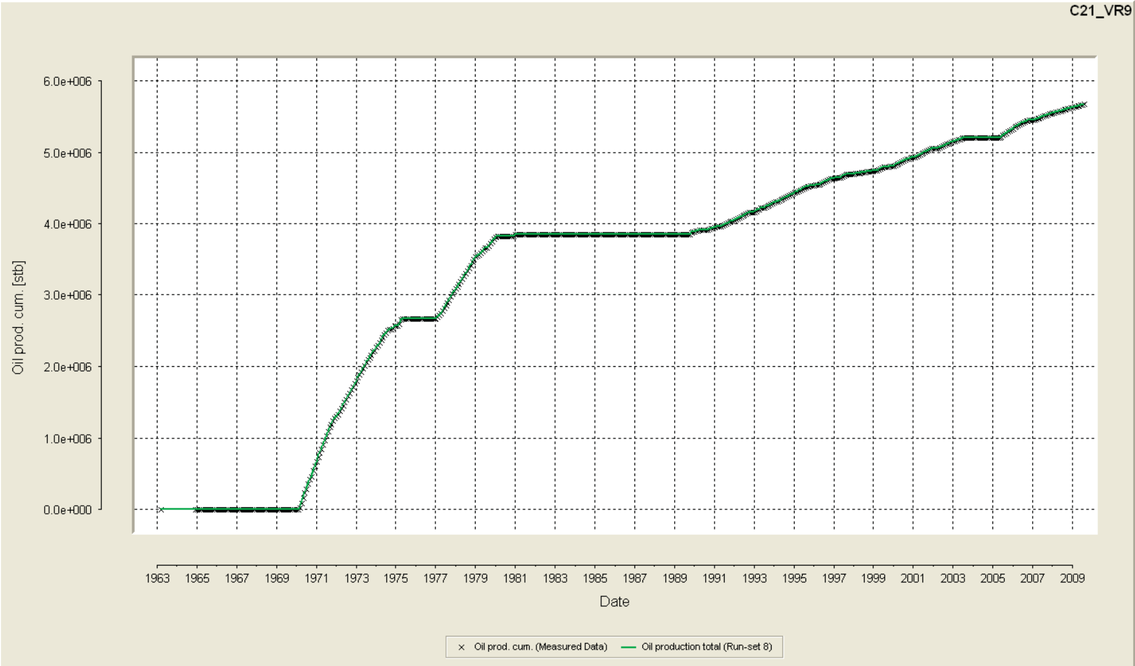

Figure C.9 C21_VR9 Cumulative oil production

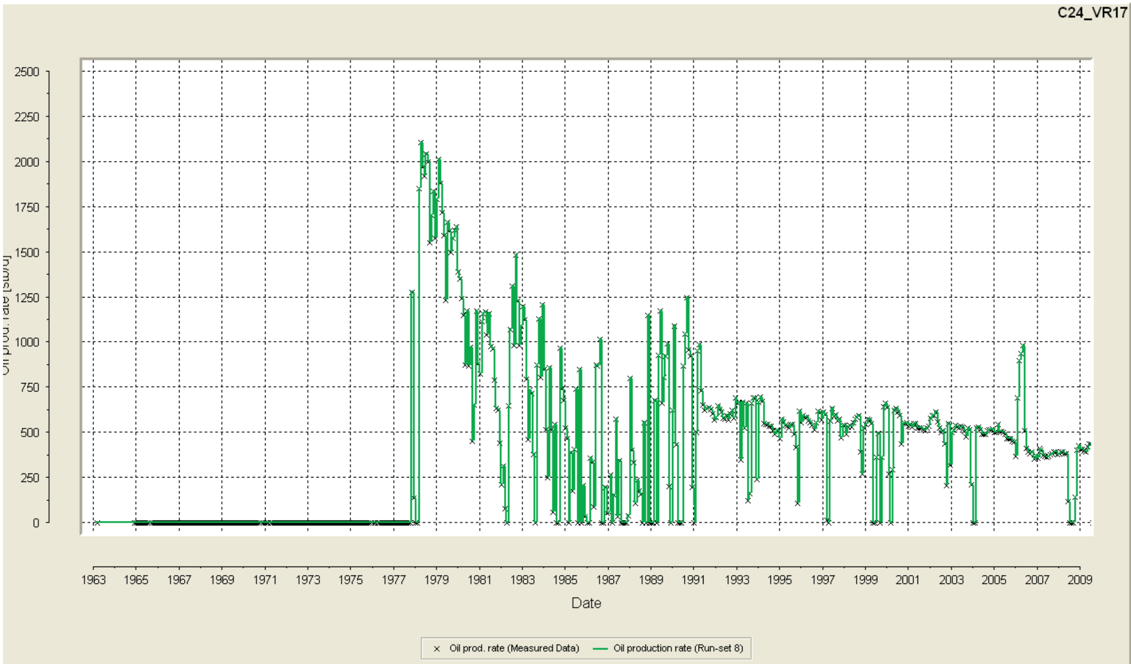

Figure C.10 C24_VR17 Oil rate in history matching period

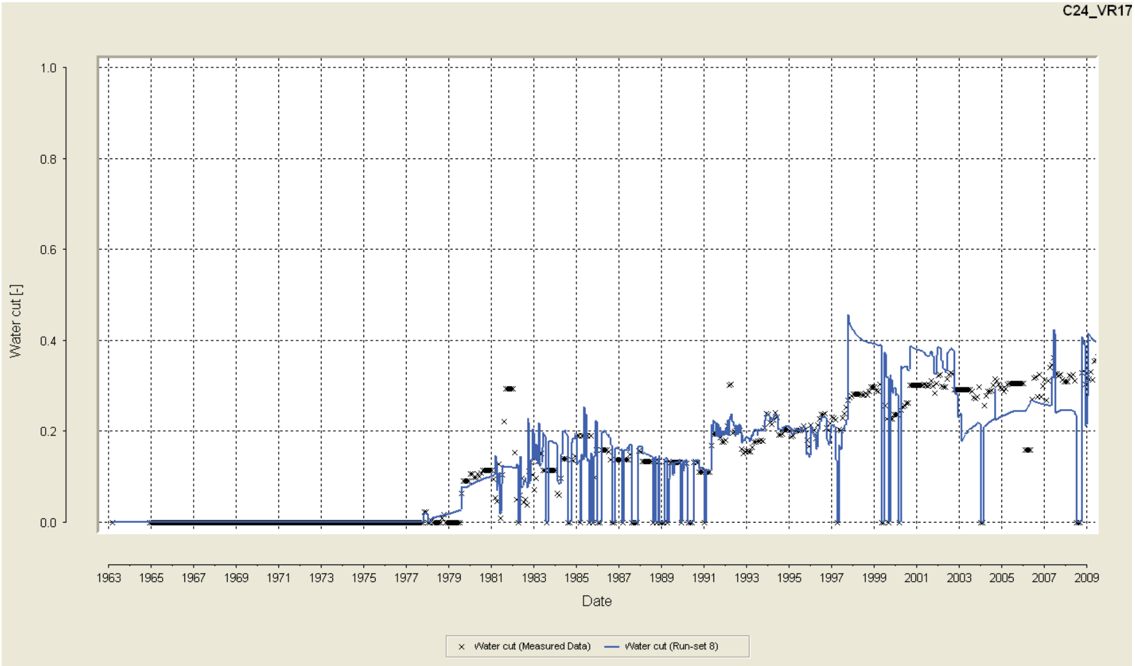

Figure C.11 C24_VR17 Water Cut

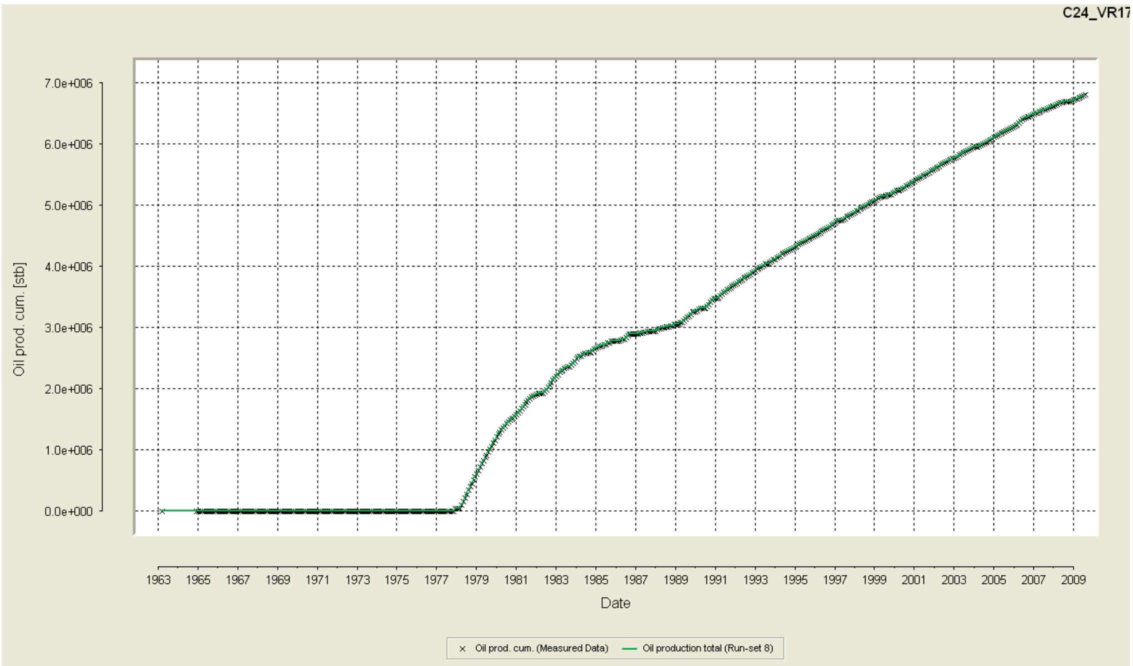

Figure C.12 C24_VR17 Cumulative oil production

C.1.4 Examples for Fair HM:

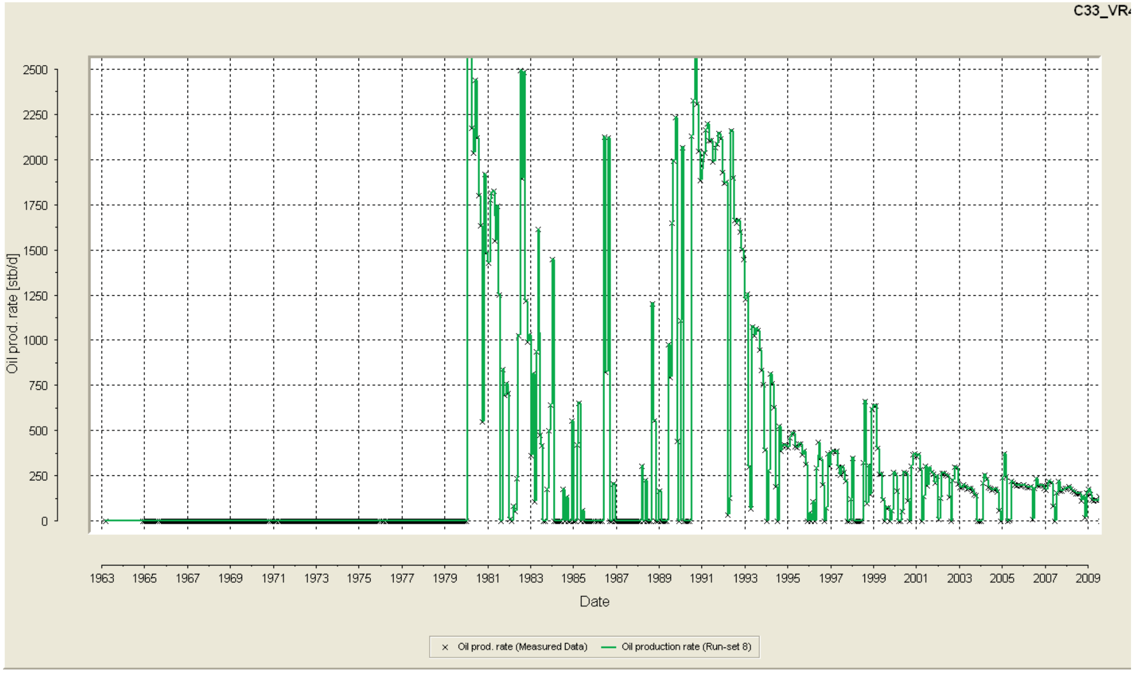

Figure C.13 C33_VR4 Oil rate in history matching period

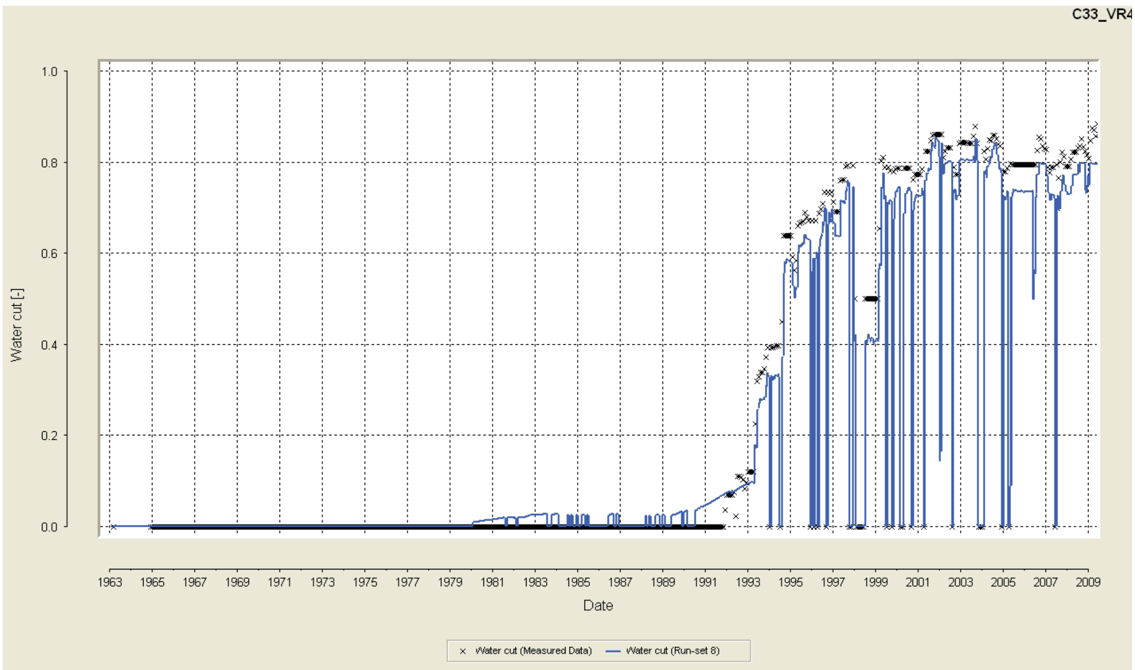

Figure C.14 C33_VR4 Water Cut

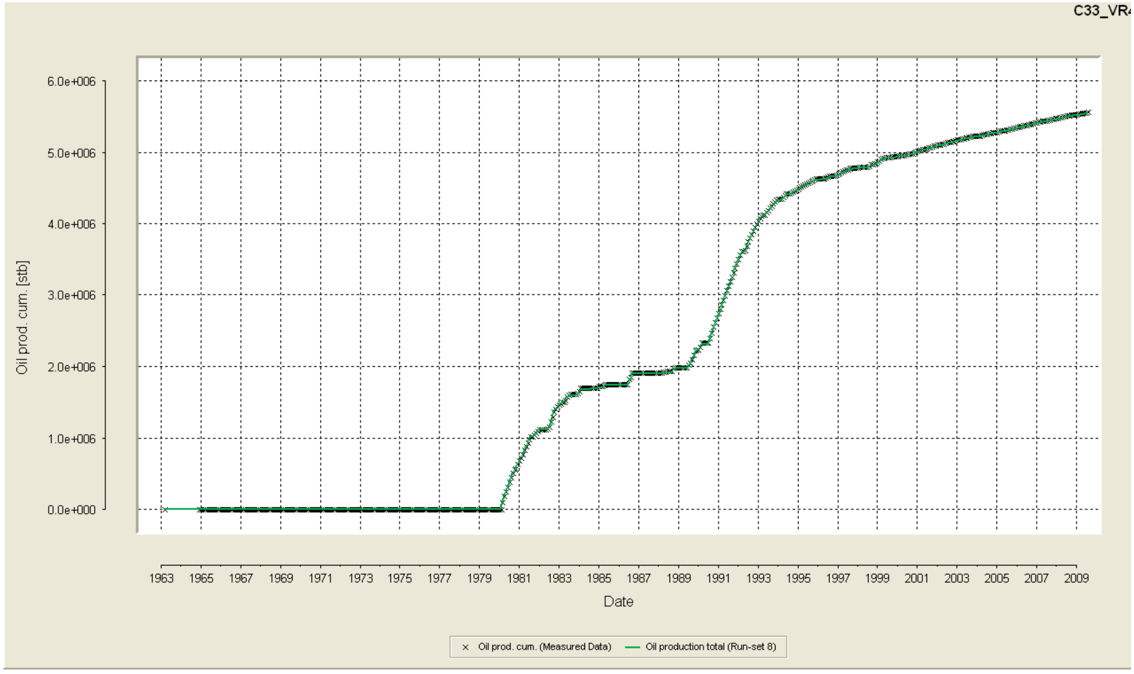

Figure C.15 C33_VR4 Cumulative oil production

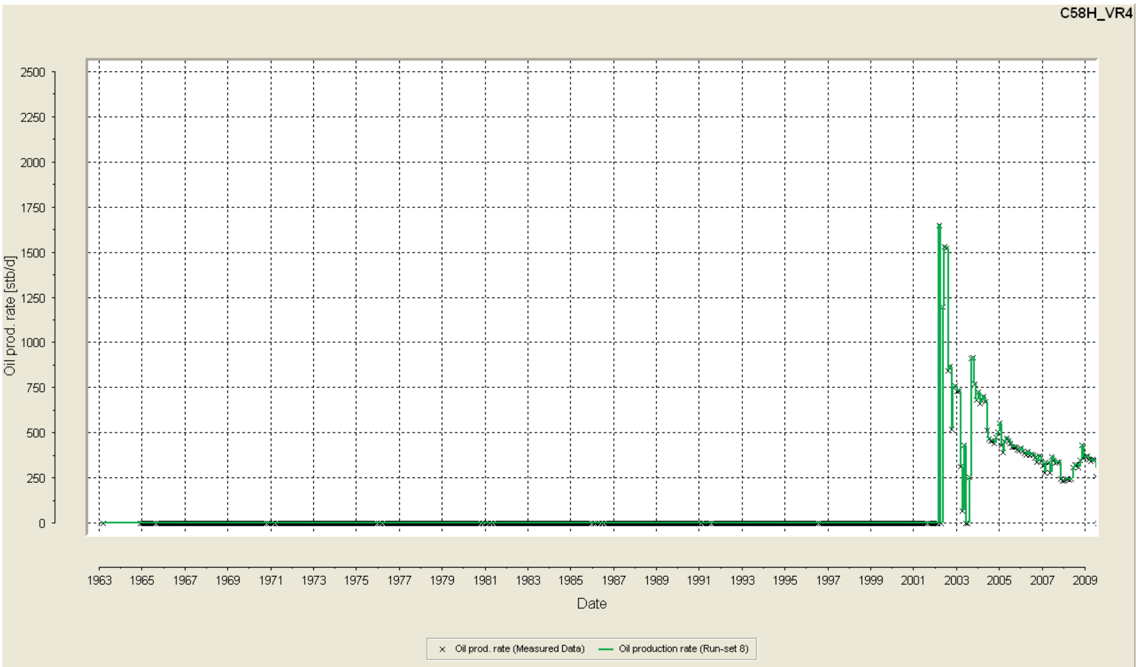

Figure C.16 C58H_VR4 Oil rate in history matching period

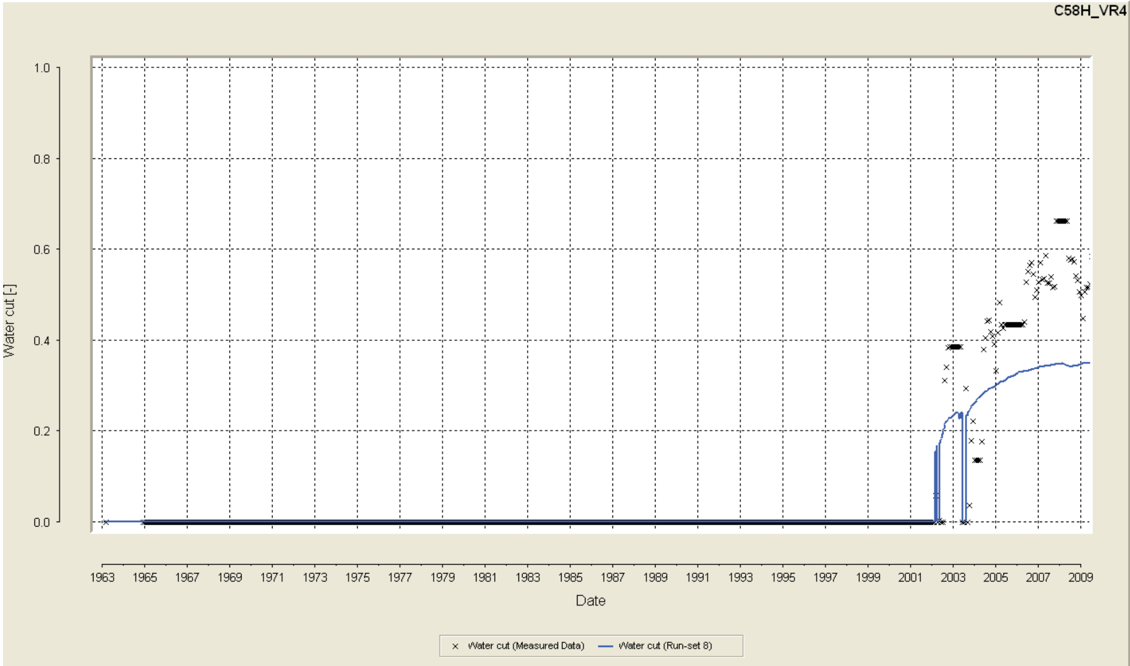

Figure C.17 C58H_VR4 Water Cut

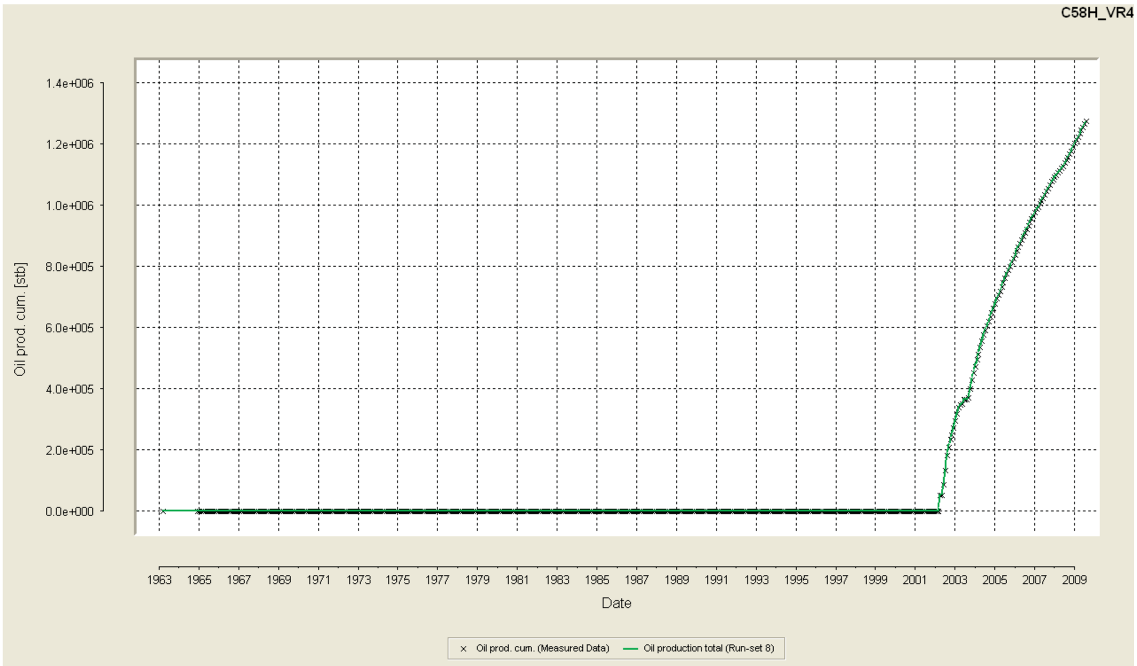

Figure C.18 C58H_VR4 Cumulative oil production

C.1.5 Examples for failed plots:

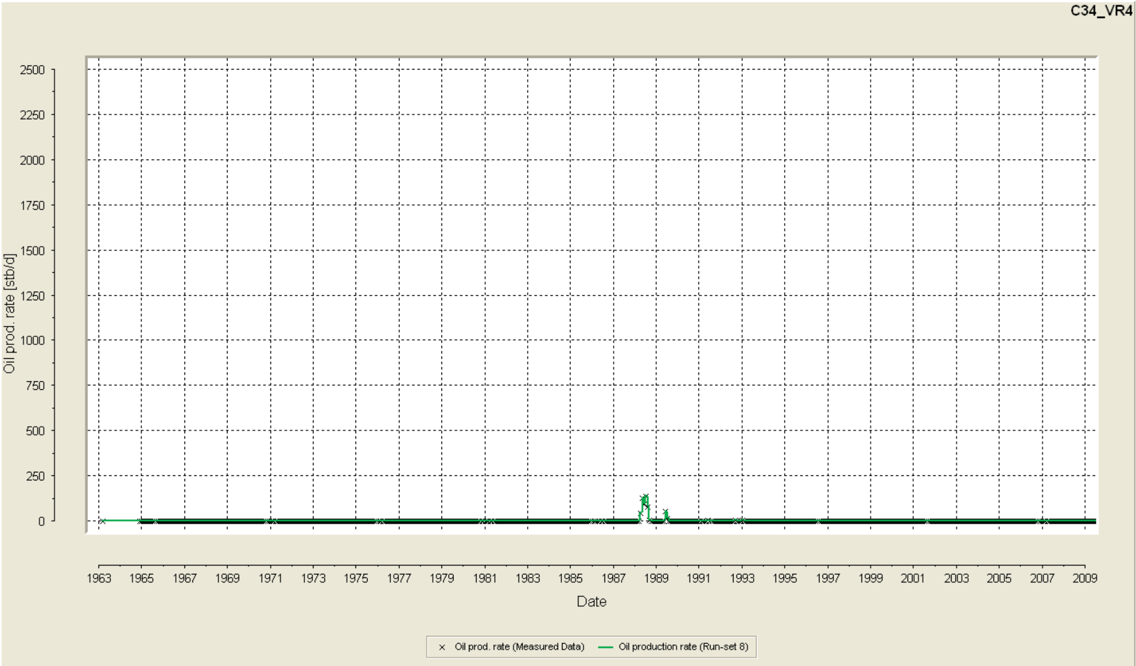

Figure C.19 C34_VR4 Oil rate in history matching period

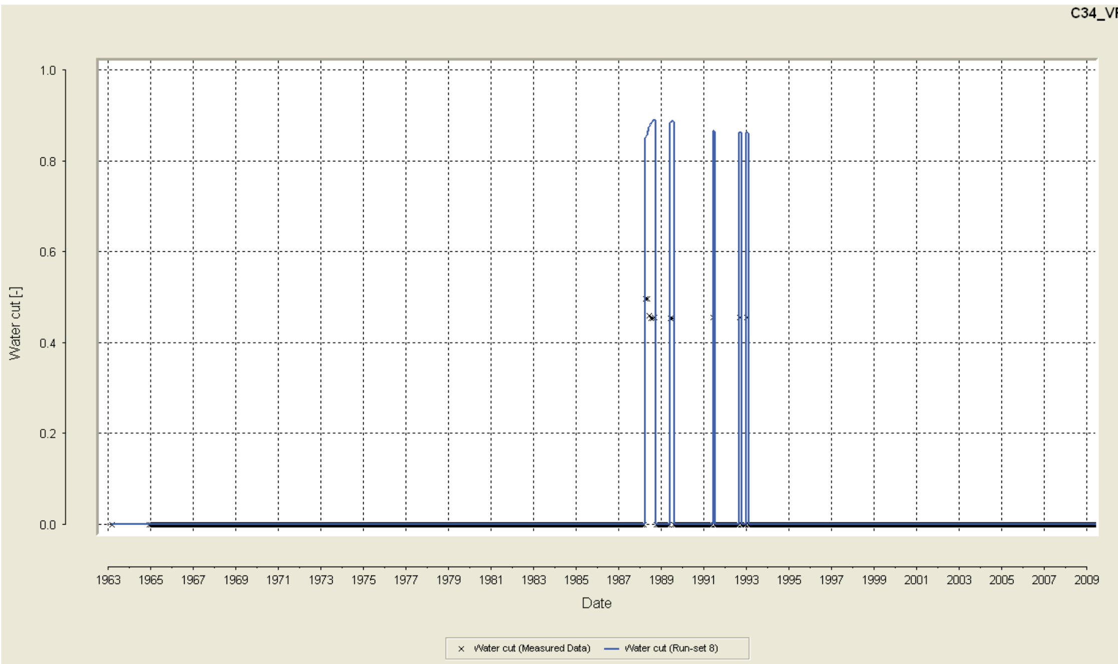

Figure C.20 C34_VR4 Water Cut

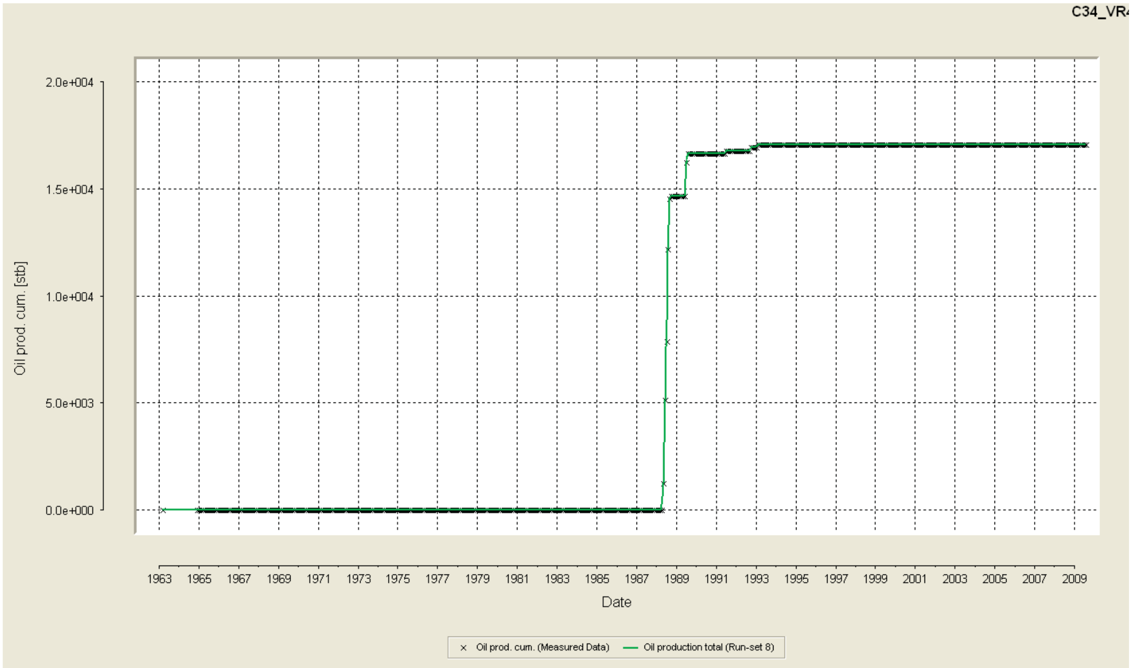

Figure C.21 C34_VR4 Cumulative oil production