North Field Qatar:
Fluids Characterization and Reservoir Modeling

SEMESTER PROJECT REPORT

BY

ARIF KUNTADI

SUPERVISOR: PROF. CURTIS H. WHITSON

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NTNU

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Table of Contents

Abstract

North Field is a very huge sub sea gas condensate reservoir located in Qatar which has estimated gas reserves more than 900 Tcf. This project has main objectives to characterize the North Field's fluids and to develop its reservoir simulation model. Having done those tasks then we run the compositional simulation to see the potentiality of this field. Almarry and Al-Saadoon[1] have developed the equation of state (EOS) model for North Field's fluids but they did not provide clearly the parameters they resulted. This project, then, has been developing the new EOS model with Soave-Redlich-Kwong (SRK) EOS and characterizing the C_{7+} fraction by Gamma Distribution model into 13 components so that the final EOS model has 24 components (EOS24). Matching the EOS24 model to the measured data is one of the important steps during developing the EOS model; at this step we get good agreement after we made some adjustments mainly for the C_{7+} properties. The EOS24 model matching gives an average error of 1.8 % which is a reasonable deviation.

Due to the broadness of North Field's area of and the limitation of allowable number of active grid blocks used in the reservoir simulator we use, in this project we only develop reservoir model for one concession block. The developed reservoir model is a full field Cartesian model, no communication layering system between main layers, uniform porosity, and uniform permeability in each main layer. We run the model with depletion production scenario and the plateau rate of 2000 MMSCF/D for 50 years production period. Completing 20 production wells with all layers perforated since the beginning gives promising recovery at the end of production period, the ultimate recovery of 55 % for condensate and 78 % for gas with the well bottom hole pressure more than 900 psia.

This project also proposes a general description of petroleum stream management strategy of North Field which consists of some steps to manage the streams in all production nodes in order to satisfy the constraints developed based on the practical considerations.

Introduction

North Field, firstly discovered in 1971, is situated just offshore to the North East of the peninsular landmass of Qatar as shown in **Fig. 18** and, geologically, the extension of Iran's South Pars gas field. It has gas reserves estimated more than 900 Tcf and considered as the world's second largest holder of gas reserves after Russia or the largest single gas field in the world. This field covers an area of more than 6000 square kilometers which is nearly half the size of the state of Qatar land. North Field reservoir which is a part of Permian Khuff formation mainly consists of mixture of dolomite and limestone[7] and has 4 main layers (starting from the top): K1, K2, K3 and K4.

Due to its huge gas reserves so the appropriate development of North Field is needed to be done carefully in order the gas reserves which have been discovered in this field could be recovered optimally. One of the tools which usually used in petroleum engineering to give comprehensive evaluation of the potentiality of the reservoir is reservoir simulation. Simulation will give the accurate result if we have an accurate description of the reservoir fluid phase behavior and use the appropriate reservoir model. Doing characterization of North Field's fluids to get the accurate EOS model and developing North Field reservoir simulation model are what we will reach in this project.

Almarry and Al-Saadoon, in their paper SPE 13715, have developed the equation of state (EOS) model for North Field fluids, particularly for K4 formation's fluids. They used Peng-Robinson (PR) EOS model dealing with single carbon number up to C6 and three new fractions of C_{7+} which were C_7-C_{10}, C_{11}-C_{17} and C_{18}-C_{20+}. They claimed that their model had good agreement with the laboratory measured data. They named the laboratory experiment which produced the measured data the Constant Volume Expansion (CVE) instead of the ordinary Constant Volume Depletion (CVD). The main problem when we want to use their model is that they did not provide the PR EOS parameters in their paper. They provided only the CVE laboratory data with still using heavy fraction as C_{7+} fraction.

Based on the CVE/CVD measured data in SPE 13715 this project has been developing the new EOS model with SRK EOS and 24 total components. To characterize the C_{7+} fraction we used the gamma distribution model and split it into 13 new components with the heaviest components C_{30+}. The reason why we used the SRK EOS in this work is, beside it has been used widely, because it is an excellent predictive tool for systems requiring accurate prediction of Vapor-Liquid Equilibrium (VLE), including saturation pressure calculation, and vapor properties[4]. Even though the SRK EOS gives poor prediction in liquid densities but it can be solved by using volume translation parameters.

In this project we used *PhazeComp* software developed by Zick's Technologies as a tool to do the fluid characterization and EOS model matching. *PhazeComp* is a powerful tool for Compositional Phase Behavior Modeling. In this software, after we define the composition of the gas we have, we just need to input the gamma distribution parameters we use and it will automatically determine the molar distribution of the C_{7+} fraction. And also for EOS model matching we simply define the variables that we feel have strong influence to match to the CVE/CVD data. The more detail explanations about the characterization and the data matching procedure will be discussed later in next section.

Developing an appropriate reservoir simulation model for North Field is done by collecting the basic information about reservoir description from some articles/papers then putting them together to set up the complete reservoir model in an input file of *Sensor* simulator, an easily used but powerful reservoir simulator which has been developed by Coats Engineering Inc. Since we could not get all of the detail descriptions of the North Field reservoir we, then, need to make some approximations in order the final reservoir model we get becomes reasonable to be used to run the simulation. Depletion is chosen to be the production scenario with the production period of 50 years and the field gas plateau rate of 2000 MMSCF/D. The results of the simulation of the developed model will tell us about the North Field's potentiality.

The strategy of petroleum streams management is developed because in the practical reservoir production the reservoir simulation is not enough to manage the streams in all production nodes of the reservoir whenever we have some constrains need to be satisfied.

Fluid Characterization

The basic approach used in this work is that we only develop single EOS model for a whole reservoir, and since we have 4 main layers which are isolated between each other

then we might have more than one initial gas composition. Doing complete fluid characterization until finally getting EOS model which matches to the laboratory experiment data needs several steps to do. This section will demonstrate how we characterize the North Field fluids based on the CVE/CVD data presented in the SPE 13715[1]. From this paper we have the retrograde liquid deposit and cumulative produced from CVD experiment as shown in **Table 1**, also we get the laboratory equilibrium vapor composition for 2 different pressures as shown in **Table 2**. The samples of the laboratory experiment were collected from well No. NWD 5 in the K4 formation[1].

This section, firstly, will explain about the gamma distribution method and then discuss about developing SRK EOS model based on K4 formation's fluids laboratory experiment result. Splitting the C_{7+} fraction into 13 components is the beginning step to develop the SRK EOS model and later, since the gas composition we got only at saturated pressure 4759 psig, we need to predict the initial gas composition of K4 which has initial pressure of 5300 psig and dew point pressure of 5120 psig. Matching the developed SRK EOS model will be done by adjusting some variables which have strong influence where finally can give reasonable deviations with the measured CVD experiment data. The final step of characterization is condensate viscosity matching, which is adjusting the critical Z-factor parameter of the EOS model in order to be able to be used in *Sensor* to give accurate viscosity prediction during simulation.

Having got the complete SRK EOS model for K4 formation we will be able to use the model for all formations/layers but we need to do a little work to predict the initial gas composition for other formations/layers since K4 formation is isolated from other formations.

The Gamma Distribution Model

The exponential distribution model is one model which is sufficiently used in many cases to describe the heavy fraction molar distribution. It assumes that all reservoir fluids having a given C_{7+} molecular weight have the same molar distribution, which is realistically not the case. The three parameter gamma distribution is a more general model[4]. The gamma distribution model is based on the Gamma Distribution function and characterized by three parameters which are α, η and M_{7+}. The gamma probability density function is

$$p(M) = \frac{(M-\eta)^{\alpha-1}\exp\left\{-\left[\left(M-\eta\right)/\beta\right]\right\}}{\beta^{\alpha}\,\Gamma(\alpha)} \quad \ldots\ldots (1)$$

where Γ= gamma function, and β is given by

$$\beta = \frac{M_{7+}-\eta}{\alpha} \quad \ldots\ldots (2)$$

The key parameter α defines the form of the distribution and its value usually ranges from 0.5 to 2.5 for reservoir fluids, which is $\alpha = 1$ gives an exponential distribution. The gamma distribution for different value of α is shown in **Fig. 1**. The next key parameter η can be physically interpreted as the minimum molecular weight found in the C_{7+} fraction. An approximate relation between α and η is

$$\eta \approx \frac{110}{1-\left(1+4/\alpha^{0.7}\right)} \quad \text{.....(3)}$$

for reservoir fluid C_{7+} fraction.

The continuous distribution p(M) is applied to petroleum fractions by dividing the are under the p(M) curve into sections as shown in **Fig. 2**. By definition, the total area under the p(M) curve from η to ∞ is unity. The area of a section is defined as normalized mole fraction zi/z_{C7+} for the range of molecular boundary M_{bi-1} to M_{bi}. If the area from η to molecular weight boundary M_b is defined as $P_0(M_b)$, then the area of Section i is $P_0(M_{bi}) - P_0(M_{bi-1})$, also shown in **Fig. 2**. Molar fraction zi can be written

$$z_i = z_{C_{7+}}\left[P_0\left(M_{bi}\right) - P_0\left(M_{bi-1}\right)\right] \quad \text{.....(4)}$$

Average molecular weight in the same interval is given by

$$M_i = \eta + \alpha\beta\frac{P_1\left(M_{bi}\right) - P_1\left(M_{bi-1}\right)}{P_0\left(M_{bi}\right) - P_0\left(M_{bi-1}\right)} \quad \text{.....(5)}$$

where $P_1 = QS$ .....(6)

and $$P_1 = Q\left(S - \frac{1}{\alpha}\right) \quad \text{.....(7)}$$

where $Q = e^{-y}y^{\alpha}\Gamma\left(\alpha\right)$ .....(8)

$$S = \sum_{j=0}^{\infty} y^j \left[\prod_{k=0}^{j}\left(\alpha + k\right)\right]^{-1} \quad \text{.....(9)}$$

and $$y = \frac{M_b - \eta}{\beta} \quad \text{.....(10)}$$

Note that $P_0(M_{b0}=\eta) = P_1(M_{b0}=\eta) = 0$.
The summation in Eq. (9) should be performed until the last term is < 1 x 10^{-8}.

K4 Formation

The K4 formation is the deepest main layers of the Khuff formation as shown in **Fig. 7**, it has the thickest productive pay zone and it contributes the biggest initial gas in place (IGIP) for North Field[8]. The equilibrium gas composition of K4 at 4759 psig which was provided in SPE 13715 will be the starting point to do characterization. The whole step of this work is done by *PhazeComp* software, and we just need to put all of the characterization steps required in the input file of *PhazeComp*. Basically what will be

demonstrated here are the sequences of developing input file of *PhazeComp* since the detail and actual calculations will be done in this software internally and we just can see the results which are produced as output file. The input files used in this work are presented in **Appendix A**.

C_{7+} Characterization

As shown in **Table 2** the composition of K4's gas at 4759 psig consists of 12 components which are single carbon number (SCN) up to C_6 and C_{7+} fraction. In this project we are splitting the C_{7+} fraction into 13 components which are SCN from C_7 to C_{16} and fraction of C_{17}-C_{19}, C_{20}-C_{29} and C_{30+}. The first step is defining the characterization of the original gas composition (12 components) as provided in SPE 13715 and specifying EOS SRK as EOS model we are using, and afterward we input its composition. We do not need to give properties for all components because *PhazeComp* has properties library to complete this job and for pseudo components it will use correlations to predict the properties. Then we develop new characterization which contains the additional new components where the total number of components becomes 24 (EOS24). We also have to give the binary interaction parameters (BIP) for each components based on the SRK EOS model. In this C_{7+} characterization we use the Søreide correlation to estimate specific gravity of the C_{7+} fraction.

To use gamma distribution model to split C_{7+} fraction we need to input the three parameters which are α, η and M_{7+}. The Gamma model used to define SCN and C_{30+} molecular weights and properties uses the (unknown) reservoir condensate C_{7+} and not the original reservoir gas C_{7+}. This will help improve the description of reservoir and surface condensate because of a more realistic liquid-like C_{30+} pseudo, without affecting adversely the description of reservoir gas which has very little amount of the C_{30+} pseudo. For initialization the EOS24 model we use the average molecular weight of the fractions of C_{17}-C_{19}, C_{20}-C_{29} and C_{30+} which is in the range of 200 - 250. Then when splitting the C_{7+} molar fraction into 13 new molar fractions of new components then we use the average molecular weight of C_{7+} which is in the range of 130 - 145 as provided in SPE 13715.

Initial Gas Composition Prediction

From the previous step we got the SRK EOS model which has 24 components (EOS24) and also we got the EOS24 gas composition at saturated pressure of 4759 psig. In order to get initial gas composition we will use this gas composition as the base data to do prediction. The first step is putting the EOS24's equilibrium gas composition as feed to do the Constant Composition Expansion (CCE) experiment at 4759 psig as its dew point to get the incipient oil composition. By assuming the value of the oil fraction of incipient oil of the equilibrium gas we then add this incipient oil to the equilibrium gas to get the initial gas composition.

EOS Model Matching

The previous two steps gave the EOS24 model and initial gas composition, and then here we will demonstrate how we match those 2 results to the original laboratory measured data. From SPE 13715 we get 4 variables from CVD laboratory experiments which are used to be matched. Those variables are:

1. Retrograde liquid deposit/liquid percent volume.
2. Cumulative produced volume.
3. Molecular weight of C_{7+}.
4. Gas Z-factor.
5. Gas composition at 4759 psig and 3244 psig

Beside the variables of CVD experiment we also will match the saturation pressure of EOS24 gas produced from gamma distribution model to 4759 psig and the saturation pressure of the EOS24 predicted initial gas composition to 5120 psig. The final variables which adjusted during matching are:

1. Mole fraction of C_{7+}.
2. Specific gravity of C_{7+} (Søreide factor)
3. Average molecular weight of the last 3 fractions of EOS24.
4. Average molecular weight of C_{7+}.
5. Binary Interaction Parameter of C_1 and C_{30+}.
6. Boiling Point of C_{30+}
7. Fraction of incipient oil added to the equilibrium gas at 4759 psig.

In the *PhazeComp* input file we have to specify the variables of CVD measured data for any given pressure. During the matching *PhazeComp* will use these data as the base to calculate the deviations. In the other side the way how we adjust the 7 variables above is by specifying the initial guess value, lower boundary and upper boundary. By this information *PhazeComp* will be matching the 5 given CVD variables and 2 saturated pressures by adjusting the 7 given variables until the average deviation reaches reasonable value.

Condensate Viscosity Matching

The base data to match condensate viscosity is taken by correlation. First we make 3 stages separator test for the final EOS model (EOS24) with the following conditions:

1. Stage 1: T= 220 ^{o}F; P= 2500 psia.
2. Stage 2: T= 100 ^{o}F; P= 500 psia.
3. Stage 3: T= 60 ^{o}F; P= 14.7 psia.

The expected condensate cumulative GOR and API gravity at surface condition are able to be measured by *PhazeComp* and then, graphically[5], we can determine the condensate viscosity at surface when we have condensate API gravity and temperature. Having known surface viscosity and cumulative GOR we can get, graphically[5] again, the condensate viscosity at 2500 psia. This viscosity will be the base data to do the matching by adjusting the Z critical parameter of the EOS24 model.

The condensate viscosity matching can not be done in one *PhazeComp* input file together with the 3 tasks discussed before, for the separator test to get surface condensate cumulative GOR and API gravity we might use the same input file but for the matching we need to develop new input file. In this new file we put the calculated condensate viscosity at 2500 psia as the base data and then we specify initial Z critical modifier factor, lower boundary and upper boundary.

K2/K3 Formation

There is not enough information to describe initial gas composition of these 2 formations but Al-Shiddiqi and Dawe[8] mentioned that the properties of K2 and K3 formations are almost similar but different from K4 and K1. Based on this statement we make approximation that the initial gas composition of K2 and K3 are same but somewhat different from one of K4. Al-Maslamani[2] explained that the gas produced from North Field contains a corrosive constituents such as 1% H_2S and brine while Almarry and Al-Saadoon[1] gave information the H_2S content of K4's fluids is just about 0.5 %. From these 2 descriptions we might conclude that the H_2S content of K2/K3 formation's fluids should be somewhat higher than 0.5 %. Since we do not have further data then we just set the H_2S content of K2/K3 formation is 2.5 % higher than K4's and for compensation we reduce the C_1 content the same value to keep total molar fraction of 100 %. Based on this calculated composition we can predict the initial saturation pressure of K2/K3 which will be used in the simulation.

K1 Formation

Since we do not have any description of the fluids of K1 formation we, then, make approximation that its initial gas composition is the same with K4's composition.

Reservoir Modeling

To set up reservoir model for North Field we are dealing with an area more than 6000 sq km, the first problem which directly comes up is the numerous grid blocks should be used to get accurate enough result. In this project we use the free version of *Sensor* simulator which has maximum active grid blocks used only 6000. Due to this reason then we only develop the model for one concession block which covers area of 100 sq km. The example of *Sensor* input file which completely describes the developed reservoir model is presented in **Appendix B.**

Layering and Gridding

To make the model simple, from the total area of 100 sq km we assume it consists of 10 km x 10 km. SPE 39253[7] describes quite clear about the layering of North Field and the depth of the top formation (K1) which is about 8050 ft. Furthermore it tells us the thickness of K4 and total thickness of K1-K3, then between K3 and K4 there is a seal layer called upper anhydrites. K4 formation is also isolated from the deeper formation with another seal layer named median anhydrites. Al-Shiddiqi and Dawe[8] give us information about the thickness composition of K1, K2 and K3 which are 26 %, 42 %, and 32 %, respectively. TotalFinaElf[12] explains that each layer (K1, K2, K3, and K4) in South Pars, which is geologically has the same formation with North Field, is separated by seal layer. Since in SPE 39253 there is no description about the seal layer between K1, K2 and K3 then for the approximation in our model we put very thin layer (1 ft thick) between K1-K2 and K2-K3 to assure that there is no communication between those layers.

For the gridding system we choose Cartesian model and we use DX=DY= 500 m which means having 20 blocks both at the x and y directions. K1, K2 and K3 are divided into 3 sub layers each and then K4 is divided into 4 sub layers. So finally the reservoir model has dimension of 20 x 20 x 17 including the 3 seal layers between each main layer

and one bottom seal layer. The final layering and gridding model of North Field (Khuff formation) is presented in **Fig. 7**.

Formation Properties

The main formation properties will discuss here are porosity, permeability and relative permeability. Al-Shiddiqi and Dawe[8] explain that this formation has porosity ranges from 4 – 20 %, for the approximation we use uniform porosity of 15 % for the whole reservoir. They also describe that the permeability of K2/K3 ranges from 3 – 1800 mD with average 30 mD and K1/K4 relatively has lower permeability. In this model we use permeability of 100 mD for K2/K3 is and 30 mD for K1/K4. We use vertical permeability as 10 % of horizontal permeability. Detail formation properties are presented in **Table 6**.

Since we do not have enough information about formation relative permeability, we have to use the analytical relative permeability correlation. We use critical gas saturation of 10 %, connate water saturation of 20 %, and the detail relative permeability analytical basic data is presented in **Table 6**.

PVT Properties

Since we have developed the EOS model for North Field, as discussed before, in this reservoir modeling we will use that model to predict the fluids phase behavior during simulation. We use the same EOS model for all formations/layers even though they have different initial gas composition. The water properties used in this model are presented in **Table 6**.

Initialization

We set up 2 different initialization regions since we have 2 different initial gas compositions for K1/K4 and K2/K3. In this initialization we also input the reference depth, initial pressure and initial dew point pressure. Detail inputted initialization parameters are presented in **Table 6**.

Wells Completion and Production Scenario

The gas plateau rate is set at 2000 MMSCF/D with 20 production wells which means each well producing 100 MMSCF/D. The well position we just simply use the rectangular pattern as shown at **Fig. 8**. The wells are perforated at all layers. The simulation will be run under depletion production scenario for the period of 50 years. We do not limit the well bottom hole pressure at particular pressure (using default value in *Sensor* which is 0 psia) because we want to see the final bottom hole pressure at the end of the period.

Results and Discussion

Fluid Characterization

The final SRK EOS24 model parameters resulted from C_{7+} fraction characterization and EOS model matching are presented in **Table 3** and its complete BIPs are presented in **Table 4**. This EOS model gives final average deviation of 1.8 % from the measured data. It indicates that the chosen 7 variables to be adjusted during the matching, which are

dominated by C_{7+} fraction properties, give significant effects. This fact tells us that the prediction of EOS model is highly influenced by the characterization of C_{7+} fraction.

The calculated initial gas composition of North Field's fluids presented in **Table 5** indicates very little amount of C_{30+} fraction. In other words, the developed EOS24 model is dominated by SCN components which have well defined properties. It leads the model to give an accurate description of North Field's fluids phase behavior.

Fig. 3-4 show a good agreement between the calculated and the measured of volume percent liquid and produced volume in CVD experiment with the average deviation of 2.61 % and 1.28 %, respectively. While **Fig. 5** shows small different between calculated molecular weight (MW) of C_{7+} fraction in gas phase and the measured one. It tells that the model has MW of C_{7+} fraction 3.35 % higher in average. The higher MW of C_{7+} fraction of produced gas means the less condensate remains in the reservoir during pressure depletion. The difference above might be caused by the adjustment of some properties of this fraction during EOS modeling matching, particularly when matching to the measured volume produced in CVD experiment. **Fig. 6** shows that the EOS24 model has higher the compressibility factor than the measured one with the average deviation of 1.02 % which is relatively small.

The comparison of the equilibrium vapor composition at 4759 psig and 3578 psig presented in **Table 2** gives indication that small difference mainly happens at the light components. It correlates to the fact that the model has higher MW of C_{7+} fraction, as discussed before, which means that the model relatively contains less light components.

The separator test which is done to estimate condensate viscosity at 2500 psia gives cumulative GOR of 743.55 scf/bbl and condensate API gravity of 44.11. The surface condensate viscosity then can be determined for reservoir temperature of 220 ^{o} F and the calculated API gravity, the correlation[5] gives result of 0.8 cp. The condensate viscosity at 2500 psia is determined as 0.34 cp also by correlation for surface viscosity of 0.8 cp and the calculated cumulative GOR. Afterward we set this condensate viscosity as measured data and then run *PhazeComp* to get the Z critical parameter, the final result gives perfect match with no deviation at all. The adjusted Z critical parameter is tabulated in **Table 3**.

The initial gas composition of K2/K3 after adjusted in term of H_2S and C_1 contents is presented in **Table 5**. This composition gives initial dew point pressure of 4930 psig.

Simulation Modeling and Results

The developed reservoir model has been simulated for 50 years with depletion production scenario. Since we have got an EOS model from the previous modeling we choose to run compositional simulation to get better description. The simulation results are presented in **Fig. 9-15**.

Fig. 9 shows the gas production rate for all formations/layers and a whole field. Since we do not put any constraint for minimum well bottom hole pressure, the simulation predicted that the model is able to produce the gas plateau rate for 50 years. The contribution of each formation basically depends on their thickness which correlates to number of the perforated grid blocks since we perforated all the layers during wells completion. The average gas production rates of K4, K2, K3 and K1 are 900 MMSCF/D, 450 MMSCF/D, 370 MMSCF/D, and 280 MMSCF/D, respectively. Those rates are seen

almost constant for a whole production period but actually there is very small decreasing rate of K1/K4 which is then compensated by an equivalent rate increasing of K2/K3 to keep the plateau rate constant. We can see this situation little bit clearer in the last 5 years of the production period. This similar situation is also found in gas recovery plots depicted in **Fig. 11**, the slope of gas recovery of K1/K4 is somewhat higher than one of K2/K3. The ultimate field gas recovery is calculated as 78 %.

The condensate production rate plots as shown in **Fig. 10** give us the typical condensate rate plot for gas condensate reservoir which is constant in the beginning and then decreasing after the reservoir pressure reaching the dew point. The initial field condensate rate is more less 60 MSTB/D and in the end of production period it goes down to 23 MSTB/D. The condensate rate contribution of each layer to the field rate has the same situation as mentioned in the gas rate discussion. The interesting thing is found when we look at the oil recovery plots in **Fig. 12**. There is a clear fact that the condensate recovery of K1/K4 is higher than one of K2/K3. The difference of the ultimate recovery is about 2 %. There is also small difference between GOR of K1/K4 and K2/K3 as depicted in **Fig. 14.** Since **Fig. 13** tells us that the slopes of pressure depletion in all layers are relatively same, which means that the effect of layer's permeability difference is almost negligible, so the difference condensate recovery and GOR is most likely caused by the difference fluids composition of those layers. The simulation gives **t**he ultimate field condensate recovery at 55 %, this such recovery indicates that the depletion scenario is quite enough to produce condensate from the reservoir which then the gas cycling production scenario might be not needed to apply for North Field.

The similarity of the slopes of pressure depletion in all layers, including the field pressure depletion, has correlation with the well bottom hole pressure (WBHP) plots. In **Fig. 15** we arbitrary generated the WBHP of 3 production wells: P-0203, P-1008 and P-1818. The three of WBHP plots are almost the same and have the end pressure of more less 930 psia. Those similarities indicate that the total productivity index (PI) of those wells is same and it confirms with the result of calculated PI which is equal to 82.54 RB.cp/D.psi and the same for all wells. The final WBHP which is equal to 930 psia or 64 bars might be quite high enough to produce gas from bottom well to surface but it still needs further evaluation when we have fact that the wells are also producing condensate at the same time which surely needs more pressure to lift it up. Another thing needs to be considered regarding to the WBHP is the surface process location. If it is onshore then it really needs to have high WBHP because we have to have enough pressure to flow the gas and condensate, but if we have surface processes in the sea platform we do not need to have such high WBHP since we might have compressor to pressurize the produced gas.

Petroleum Streams Management Strategy

Reservoir simulation generates the petroleum stream history of a reservoir based on the model we have developed in this reservoir. It can generate the petroleum streams from the lowest aggregation level, well connection/perforated blocks, until the surface streams which are usually produced after some surface processes. To satisfy some production constraints such as field plateau rates, well rates or well bottom hole pressure the reservoir simulation is still able to handle, but when the constraints is growing to the specific and complicated constraints such as maximum H_2S contents or minimum heating

value of produced gas then the simulator might have some limitations to do so. There is a possibility that another simulator will have the facility to solve such problem/constraints but at least *Sensor* can not handle it. That is why in this section we will discuss about the petroleum streams management which is basically a tool to handle the petroleum streams (in our case produced from reservoir simulation) to satisfy some constraints by managing/controlling the petroleum streams in any production aggregation level. In our reservoir model we have known that the H_2S contents of K2/K3 layers are higher than one of K1/K4. So, for instance, we have a H_2S contents constraint of 1 % then one possibility way to satisfy that constraint is by controlling how much gas produced from K2/K3 is compared to what we produce from K1/K4 in order the surface gas produced has H_2S contents lower than 1 %.

The first step to develop petroleum streams management is setting up the complete production aggregation level from the lowest up to the highest level in our production lining system. This project proposes a simple production lining system from the well connection level to the surface process level, the schematic of this system is presented in **Fig. 16** and **Fig. 17**. **Fig. 16** describes the production lining system from well connection (in this case represented by main layers) up to the sub sea manifold and **Fig. 17** depicts the higher level from well level to the surface process as the highest level. From these two figures we can get clear description about the production nodes in each aggregation level. The production node is basically the node where it has petroleum streams either black oil or compositional streams.

The second step is completing all production nodes we have in our system as described in **Fig. 16** and **Fig. 17** with its the petroleum streams. So far what we have had is the petroleum streams which are produced from the reservoir simulation. From *Sensor* we may have streams of each layer (summing up its well connections streams), well streams and field streams. But to get the streams in one Sub Sea manifold node, for instance, we need to do extended calculation of the streams of the wells which are covered by this manifold.

The third step is determining how many constraints (with its constraint value) we have during the reservoir production life and in which production nodes we apply those constraints. There are some constraints which might be applied for North Field such as:

a. Field gas plateau rate.
b. Gas sales rate.
c. H_2S contents of produced gas.
d. Heating value of produced gas.
e. Water production rate.

The final step is doing optimization based on the streams of all the production nodes to satisfy the constraints we apply for North Field. This final step is probably the most difficult and complicated step during applying the petroleum streams management of North Field.

The North Field petroleum streams management will be done in the master thesis in the next semester, which is basically the continuation of this semester project. For doing the complicated streams management of North Field is really needed to use powerful software which has the ability to manage all kind of stuffs dealing with reservoir streams. *PetroStream Management (PSM)* which is developed by Pera a/s is probably the only software to do so. It provides the user with a set of tools to manage the

conversion of information among a multitude of models handling fluid streams[13]. We will use *PSM* to do North Field petroleum streams management.

Conclusions

North Field's fluids characterization and reservoir simulation modeling have been developed and based on these works there are some conclusions can be drawn as follows:

1. Characterization of Khuff formation's C_{7+} fraction by gamma distribution model with SRK EOS into 13 components model (making up total components into 24) gives an EOS24 model which is quite accurate to predict the fluids phase behavior in North Field.
2. The developed EOS24 matching to the CVD experiment data is highly influenced by some adjustments of the properties of C_{7+}.
3. The simulation modeling of North Field is done with the following approximations:
    a. Full field Cartesian model.
    b. There are 4 main layers (K1, K2, K3, and K4) with no communication between each others.
    c. Uniform porosity for the whole field.
    d. Uniform permeability for each main layer.
    e. Using single equation of state for all main layers but different initial gas composition.
    f. Using analytical expression to predict the relative permeability.
    g. The field is produced by depletion for 50 years production period.
    h. The gas plateau rate is set at 2000 MMSFC/D with 20 production wells and all productive layers are perforated.
4. After 50 years the well bottom hole pressure is around 930 psia and then further evaluation is still needed, based on its surface process location, to consider whether this pressure is quite enough for actual production bottom hole pressure.
5. The single equation of state used gives almost similar plots of gas recovery, condensate recovery, average pressure, GOR of main layers and plots of some well bottom hole pressures. But for the last 5 years the condensate recovery and GOR are slightly different for K1/K4 and K2/K3 which is most likely caused by the initial gas composition difference.
6. The depletion production scenario gives ultimate gas recovery of 78 % and ultimate condensate recovery of 55 % which means that gas cycling scenario might be not needed to apply in North Field to increase condensate recovery.
7. The North Field petroleum stream management consists of the steps below:
    a. Setting up the production lining system with its production nodes.
    b. Preparing the streams of all production nodes.
    c. Deciding the production constraints.
    d. Optimization to satisfy the constraints.

Nomenclature

BIP	=	binary interaction parameter
CVD	=	Constant Volume Depletion experiment
CVE	=	Constant Volume Expansion experiment
D	=	day
DX	=	length of grid blocks respect to x-axis
DY	=	length of grid blocks respect to y-axis
DZ	=	height of grid blocks
EOS	=	equation of state
EOS24	=	the equation of state model developed for North Field
FVF	=	formation volume factor
GASREC	=	gas recovery, %
GOR	=	gas oil ratio, SCF/STB
KX	=	horizontal permeability respect to x-axis
KY	=	horizontal permeability respect to y-axis
KZ	=	vertical permeability
M	=	molecular weight
M_{7+}	=	average molecular weight of the C_{7+} component
M_b	=	bounding molecular weight
M_{bi}	=	bounding molecular weight of the i^{th} fraction
M_{bi-1}	=	bounding molecular weight of the $(i-1)^{th}$ fraction
MMSCF	=	million standard cubic feet
MMSTB	=	million stock tank barrels
MSCF	=	thousand standard cubic feet
MSTB	=	thousand stock tank barrels
OILREC	=	condensate recovery, %
p(M)	=	probability density function of M
$P_0(M)$	=	the cumulative probability density function i.e. the integral of p(M)
$P_1(M)$	=	integral of the M times the Gamma distribution (probability density) function
PAVGHC	=	hydrocarbon pore volume average pressure, psia
PBH	=	well bottom hole pressure, psia
Pc	=	critical pressure
Pchor	=	parachor
PI	=	productivity index
PSM	=	PetroStream Management software
QGAS	=	gas production rate, MMSCF/D
QOIL	=	condensate production rate, MSTB/D
RB	=	reservoir barrels
s	=	dimensionless volume translation
SCF	=	standard cubic feet
SRK	=	Soave-Redlich-Kwong
STB	=	stock tank barrels
Tb	=	boiling point temperature
Tc	=	critical temperature
yi	=	molar fraction of component i

z_{7+}	=	total mole fraction of the C_{7+} component
Zc	=	critical Z-factor
zi	=	mole fraction of the i^{th} fraction or component
α	=	alpha; the shape parameter of the Gamma Distribution
β	=	beta; a composite parameter of the Gamma Distribution
γ	=	specific gravity
η	=	eta; the minimum molecular weight paramater of the Gamma Distribution
ω	=	acentric factor
Ωa, Ωb	=	constant in cubic EOS
Γ(x)	=	gamma function of x

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Tables and Figures

TABLE 1 – COMPARISON RETROGADE LIQUID AND CUMULATIVE PRODUCED OF K4 FORMATION FLUIDS				
Pressure	Retrograde Liquid Deposit (%)		Cumulative Produced (%mol)	
psig	Experiment[1]	Calculated	Experiment[1]	Calculated
5120	0.00	0.00	0.00	0.00
4759	0.14	0.20	4.54	4.83
4426	0.37	0.49	8.95	9.65
2051	0.82	0.90	14.62	15.53
3678	1.24	1.31	24.44	21.84
3244	1.79	1.72	28.14	29.77
2737	2.15	2.09	38.26	39.78
2314	2.31	2.27	47.52	48.64
1905	2.40	2.34	56.76	57.53
1468	2.37	2.32	66.87	67.21
968	2.21	2.19	78.31	78.31
550	2.02	2.01	87.53	87.44

TABLE 2 – COMPARISON EQUILIBRIUM VAPOR COMPOSITION OF K4 FORMATION				
Component	Mol Percent @ 4759 psia		Mol Percent @ 3244 psia	
	Experiment[1]	Calculated	Experiment[1]	Calculated
N2	3.36	3.35	3.22	3.38
CO2	1.76	1.76	1.76	1.76
H2S	0.53	0.53	0.53	0.53
C1	83.51	83.31	84.94	83.77
C2	5.17	5.16	5.12	5.15
C3	1.91	1.91	1.84	1.89
iC4	0.70	0.41	0.65	0.40
nC4	0.41	0.70	0.36	0.69
iC5	0.28	0.28	0.24	0.27
nC5	0.28	0.28	0.26	0.27
C6	0.39	0.39	0.31	0.37
C7+	1.70	1.94	0.77	1.51
TOTAL	100.00	100.00	100.00	100.00

TABLE 3 – FINAL SRK EOS CHARACTERIZATION FOR K4 FORMATION FLUID (EOS 24)											
Comp	M	Tc	Pc	ω	s	Tb	γ	Zc	Pchor	Ωa	Ωb
		R	psia			R					
N2	28.01	227.16	492.84	0.0370	-0.0009	139.41	0.2724	0.2918	59.10	0.4275	0.0866
CO2	44.01	547.42	1069.5	0.2250	0.2175	333.32	0.7510	0.2743	80.00	0.4275	0.0866
H2S	34.08	672.12	1300	0.0900	0.1015	382.35	0.8085	0.2829	80.10	0.4275	0.0866
C1	16.04	343.01	667.03	0.0110	-0.0025	201.57	0.1398	0.2862	71.00	0.4275	0.0866
C2	30.07	549.58	706.62	0.0990	0.0589	332.71	0.3101	0.2792	111.00	0.4275	0.0866
C3	44.10	665.69	616.12	0.1520	0.0908	416.24	0.4990	0.2763	151.00	0.4275	0.0866
i-C4	58.12	734.13	527.94	0.1860	0.1095	471.08	0.5726	0.2820	188.80	0.4275	0.0866
n-C4	58.12	765.22	550.56	0.2000	0.1103	491.14	0.5925	0.2739	191.00	0.4275	0.0866
i-C5	72.15	828.7	490.37	0.2290	0.0977	542.37	0.6312	0.2723	227.40	0.4275	0.0866
n-C5	72.15	845.46	488.78	0.2520	0.1195	557.04	0.6375	0.2684	231.00	0.4275	0.0866
C6	82.32	924.21	491.32	0.2373	0.1341	606.17	0.7036	0.2703	232.57	0.4275	0.0866
C7	95.36	988.34	457.18	0.2714	0.1429	658.66	0.7367	0.2659	263.86	0.4275	0.0866
C8	108.77	1043.9	422.82	0.3094	0.1522	707.45	0.7594	0.2614	296.05	0.4275	0.0866
C9	121.90	1094.1	389.97	0.3500	0.1697	754.04	0.7761	0.2571	327.55	0.4275	0.0866
C10	134.78	1138.6	361.66	0.3900	0.1862	796.85	0.7896	0.2533	358.48	0.4275	0.0866
C11	147.59	1178.9	336.95	0.4295	0.2018	836.84	0.8009	0.2499	389.21	0.4275	0.0866
C12	160.30	1215.6	315.31	0.4684	0.2165	874.32	0.8107	0.2466	419.72	0.4275	0.0866
C13	172.91	1249.4	296.27	0.5067	0.2302	909.51	0.8193	0.2435	449.99	0.4275	0.0866
C14	185.42	1280.6	279.43	0.5444	0.2430	942.65	0.8270	0.2406	480.01	0.4275	0.0866
C15	197.82	1309.5	264.48	0.5814	0.2548	973.9	0.8340	0.2377	509.77	0.4275	0.0866
C16	210.11	1336.3	251.14	0.6178	0.2657	1003.4	0.8404	0.2349	539.27	0.4275	0.0866
C17-19	233.39	1383.1	229.29	0.6857	0.2843	1055.8	0.8513	0.2298	595.13	0.4275	0.0866
C20-29	299.51	1493.7	184.6	0.8712	0.3239	1183.8	0.8764	0.2161	753.83	0.4275	0.0866
C30+	477.34	1616.9	167.56	1.0411	0.1154	1309.7	0.9215	0.2058	1180.62	0.4275	0.0866

TABLE 4 – BIP's FOR FINAL SRK EOS CHARACTERIZATION OF K4 FORMATION FLUID												
Comp	**N2**	**CO2**	**H2S**	**C1**	**C2**	**C3**	**i-C4**	**n-C4**	**i-C5**	**n-C5**	**C6**	**C7**
N2	0	0	0.12	0.02	0.06	0.08	0.08	0.08	0.08	0.08	0.08	0.08
CO2	0	0	0.12	0.12	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
H2S	0.12	0.12	0	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.03
C1	0.02	0.12	0.07	0	0	0	0	0	0	0	0	0
C2	0.06	0.15	0.06	0	0	0	0	0	0	0	0	0
C3	0.08	0.15	0.06	0	0	0	0	0	0	0	0	0
i-C4	0.08	0.15	0.06	0	0	0	0	0	0	0	0	0
n-C4	0.08	0.15	0.06	0	0	0	0	0	0	0	0	0
i-C5	0.08	0.15	0.06	0	0	0	0	0	0	0	0	0
n-C5	0.08	0.15	0.06	0	0	0	0	0	0	0	0	0
C6	0.08	0.15	0.05	0	0	0	0	0	0	0	0	0
C7	0.08	0.15	0.03	0	0	0	0	0	0	0	0	0
C8	0.08	0.15	0.03	0	0	0	0	0	0	0	0	0
C9	0.08	0.15	0.03	0	0	0	0	0	0	0	0	0
C10	0.08	0.15	0.03	0	0	0	0	0	0	0	0	0
C11	0.08	0.15	0.03	0	0	0	0	0	0	0	0	0
C12	0.08	0.15	0.03	0	0	0	0	0	0	0	0	0
C13	0.08	0.15	0.03	0	0	0	0	0	0	0	0	0
C14	0.08	0.15	0.03	0	0	0	0	0	0	0	0	0
C15	0.08	0.15	0.03	0	0	0	0	0	0	0	0	0
C16	0.08	0.15	0.03	0	0	0	0	0	0	0	0	0
C17-19	0.08	0.15	0.03	0	0	0	0	0	0	0	0	0
C20-29	0.08	0.15	0.03	0	0	0	0	0	0	0	0	0
C30+	0.08	0.15	0.03	0.06887	0	0	0	0	0	0	0	0

Comp	**C8**	**C9**	**C10**	**C11**	**C12**	**C13**	**C14**	**C15**	**C16**	**C17-19**	**C20-29**	**C30+**
N2	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
CO2	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
H2S	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
C1	0	0	0	0	0	0	0	0	0	0	0	0.06887
C2	0	0	0	0	0	0	0	0	0	0	0	0
C3	0	0	0	0	0	0	0	0	0	0	0	0
i-C4	0	0	0	0	0	0	0	0	0	0	0	0
n-C4	0	0	0	0	0	0	0	0	0	0	0	0
i-C5	0	0	0	0	0	0	0	0	0	0	0	0
n-C5	0	0	0	0	0	0	0	0	0	0	0	0
C6	0	0	0	0	0	0	0	0	0	0	0	0
C7	0	0	0	0	0	0	0	0	0	0	0	0
C8	0	0	0	0	0	0	0	0	0	0	0	0
C9	0	0	0	0	0	0	0	0	0	0	0	0
C10	0	0	0	0	0	0	0	0	0	0	0	0
C11	0	0	0	0	0	0	0	0	0	0	0	0
C12	0	0	0	0	0	0	0	0	0	0	0	0
C13	0	0	0	0	0	0	0	0	0	0	0	0
C14	0	0	0	0	0	0	0	0	0	0	0	0
C15	0	0	0	0	0	0	0	0	0	0	0	0
C16	0	0	0	0	0	0	0	0	0	0	0	0
C17-19	0	0	0	0	0	0	0	0	0	0	0	0
C20-29	0	0	0	0	0	0	0	0	0	0	0	0
C30+	0	0	0	0	0	0	0	0	0	0	0	0

TABLE 5 – CALCULATED INITIAL GAS COMPOSITION OF KHUFF FORMATION		
Component	K1/K4	K2/K3
	%mol	%mol
N2	3.35	3.35
CO2	1.76	1.76
H2S	0.53	3.03
C1	83.27	80.77
C2	5.16	5.16
C3	1.91	1.91
i-C4	0.41	0.41
n-C4	0.70	0.70
i-C5	0.28	0.28
n-C5	0.28	0.28
C6	0.39	0.39
C7	0.49	0.49
C8	0.36	0.36
C9	0.27	0.27
C10	0.20	0.20
C11	0.15	0.15
C12	0.12	0.12
C13	0.09	0.09
C14	0.07	0.07
C15	0.05	0.05
C16	0.04	0.04
C17-19	0.07	0.07
C20-29	0.06	0.06
C30+	0.01	0.01
TOTAL	100.00	100.00

TABLE 6 – RESERVOIR MODELLING DESCRIPTION FOR SIMULATION

GEOMETRY		
Surface Area	10 km x 10 km	
Gridding of Cartesian Model	20 x 20 x 17	
Size of total reservoir, cuft	32808 x 32808 x 1721	
DX = DY, ft	1640 (500 m)	
Depth to top of formation, ft	8050	
ROCK AND FLUIDS PROPERTIES		
Porosity, %	15	
Permeability		
Layer	KX=KY, mD	KZ, mD
K1	30	3
K2	100	10
K3	100	10
K4	30	3
Rock Compressibility, 1/psi	5.0E-06	
Reservoir Temperature, F	220	
Water compressibility, 1/psi	2.64E-06	
Water FVF, RB/STB	1.0375	
Water density, lbs/cuft	62.37	
Water viscosity, cP	0.65	
INITIAL CONDITION		
K4 Layer		
Initial Pressure, psia	5300	
Reference Depth, ft	9600	
Dew point pressure, psia	5120	
K3 Layer		
Initial Pressure, psia	5180	
Reference Depth, ft	8500	
Dew point pressure, psia	4930	
RELATIVE PERMEABILITY ANALYTICAL DATA		
Connate water saturation (Swc)	0.2	
Residual oil saturation to water (Sorw)	0.2	
Residual oil saturation to gas (Sorg)	0.2	
Critical gas saturation (Sgc)	0.1	
Relative permeability of water at Sw=1-Sorw, Sg=0 (krwro)	0.5	
Relative permeability of gas at Sw=Swc, So=Sorg (krgro)	0.33	
Relative permeability of oil at Sw=Swc, Sg=0 (krocw)	0.9	
Exponent for krw curve (nw)	3	
Exponent for krow curve (now)	3	
Exponent for krg curve (ng)	3	
Exponent for krog curve (nog)	3	

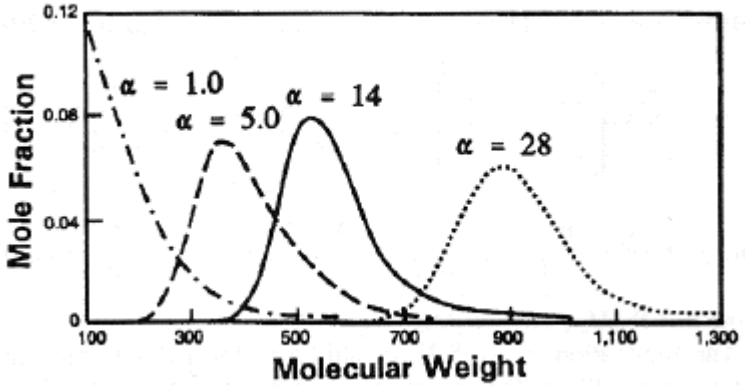

Fig. 1 – Gamma distributions for petroleum residue (after Whitson and Brulé[4])

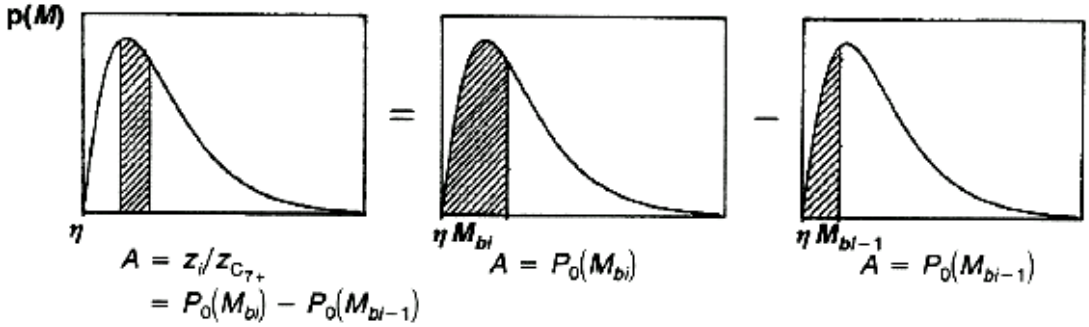

Fig. 2 – Schematic showing the graphical interpretation of areas under the gamma density function p(M) that are proportional to normalized mole fraction; A = area (after Whitson and Brulé[4])

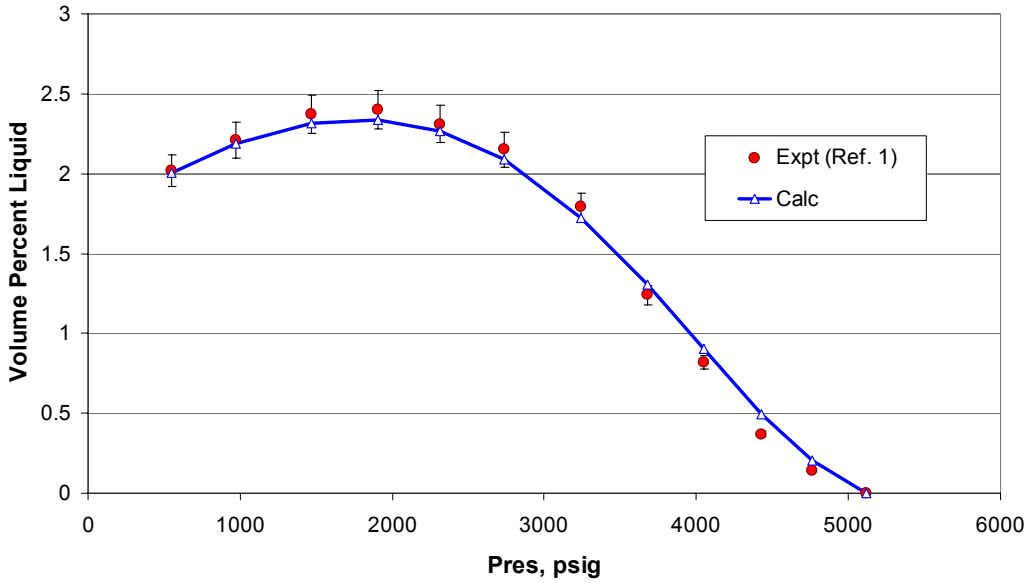

Fig. 3 – Comparison volume percent liquid during Constant Volume Depletion at 220 F

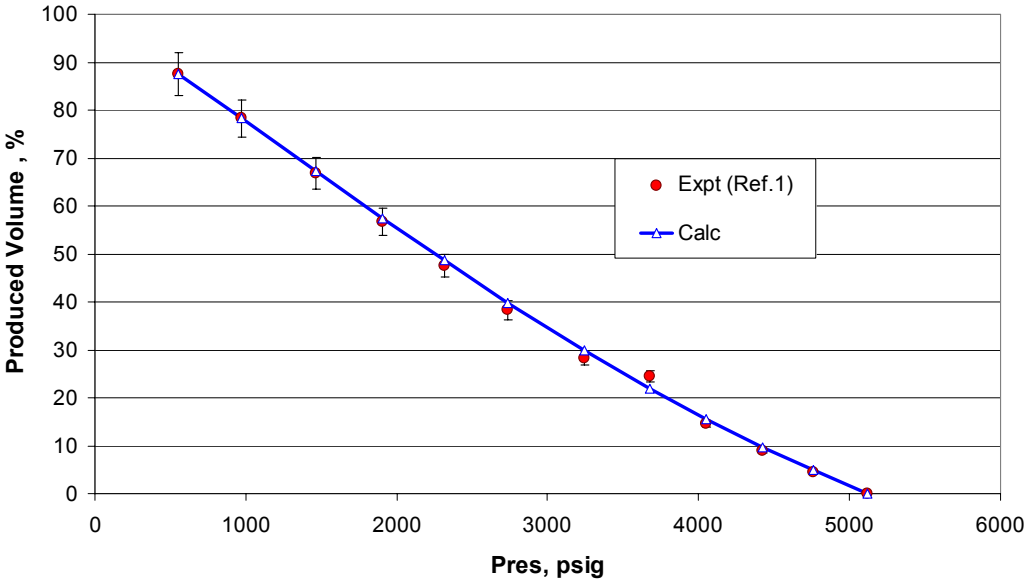

Fig. 4 – Comparison produced volume during Constant Volume Depletion at 220 F

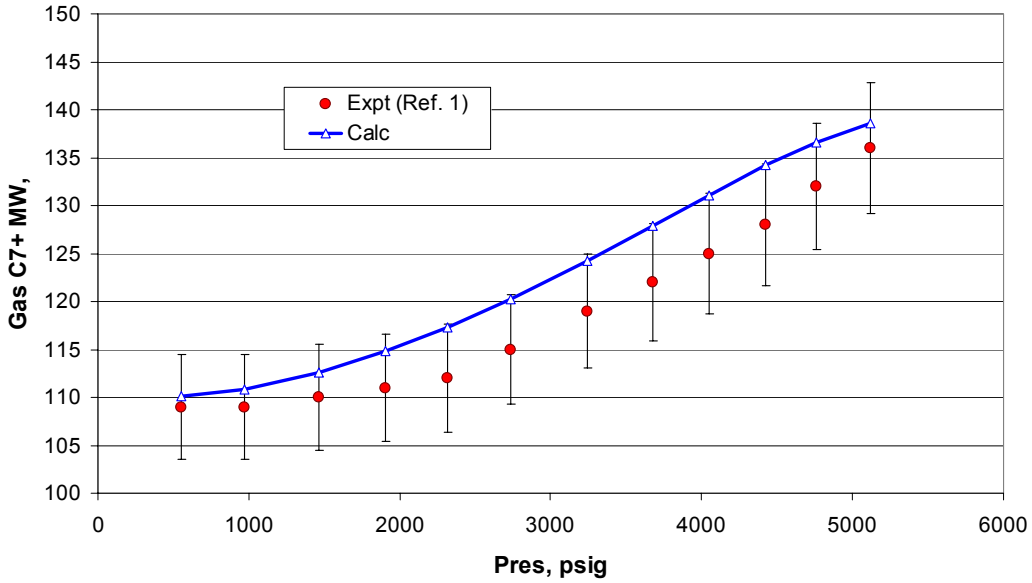

Fig. 5 – Comparison molecular weight of C7+ during Constant Volume Depletion at 220 F

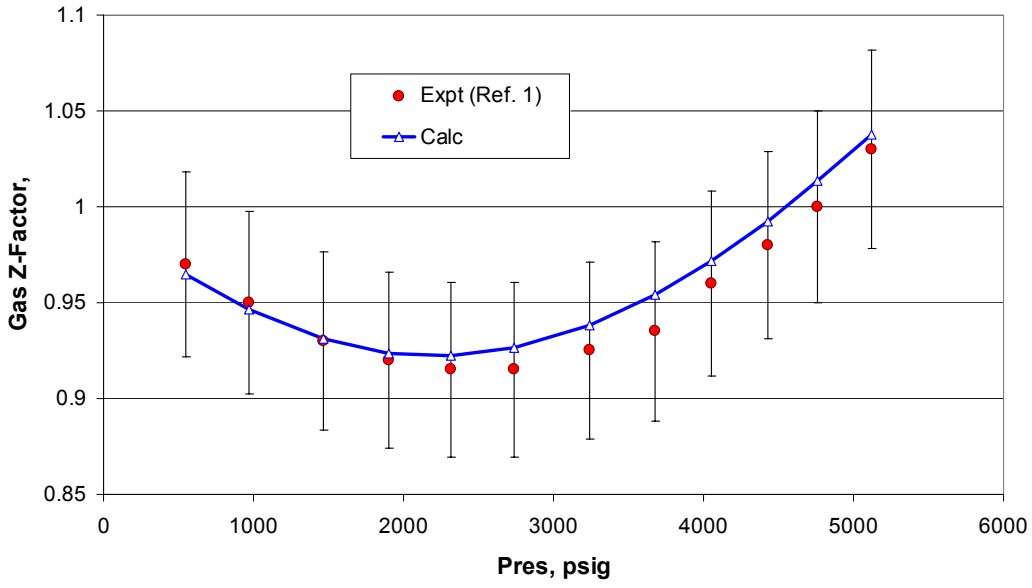

Fig. 6 – Comparison gas Z-factor during Constant Volume Depletion at 220 F

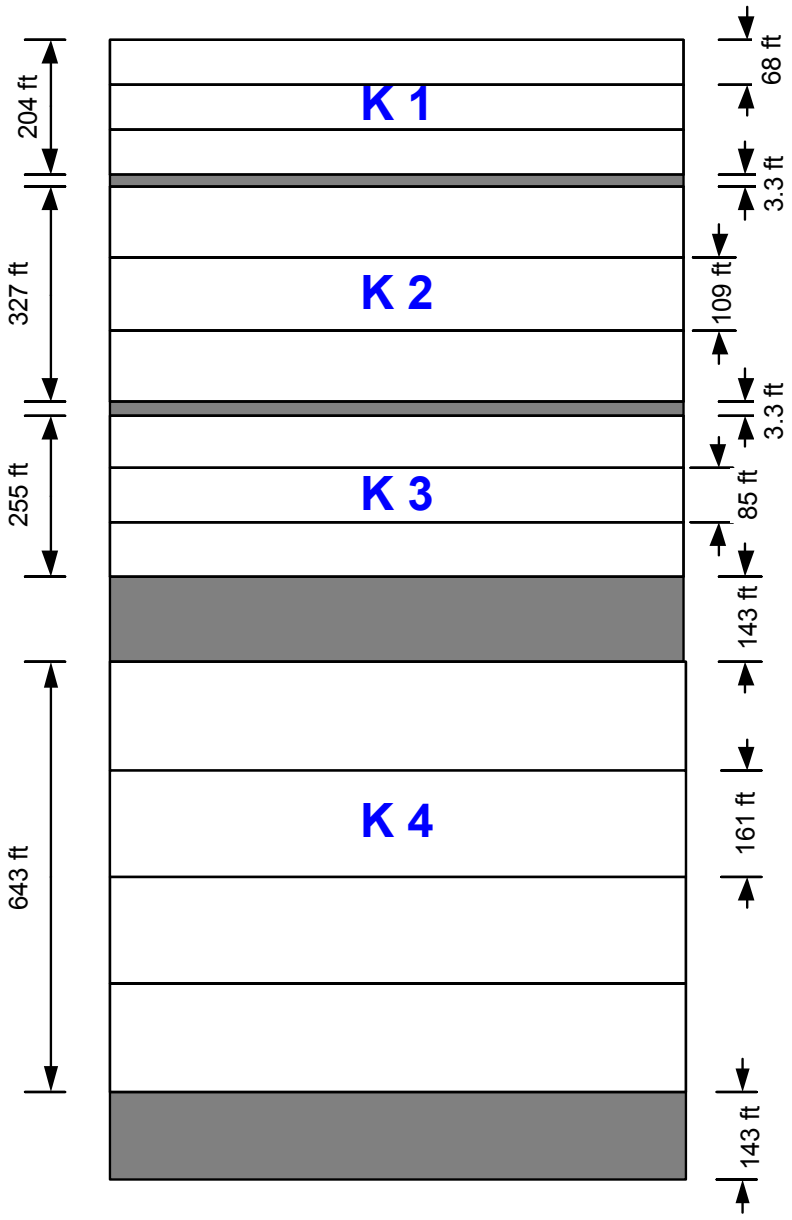

Fig. 7 – Khuff formation layering system

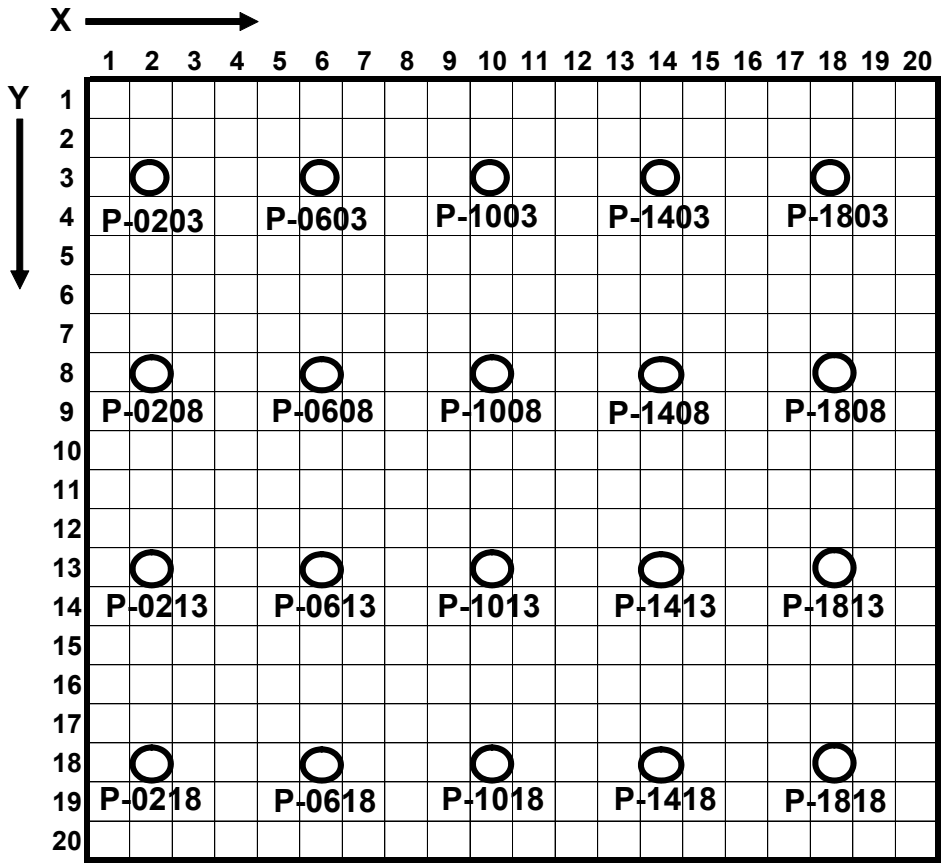

Fig. 8 – North Field Production Well Position

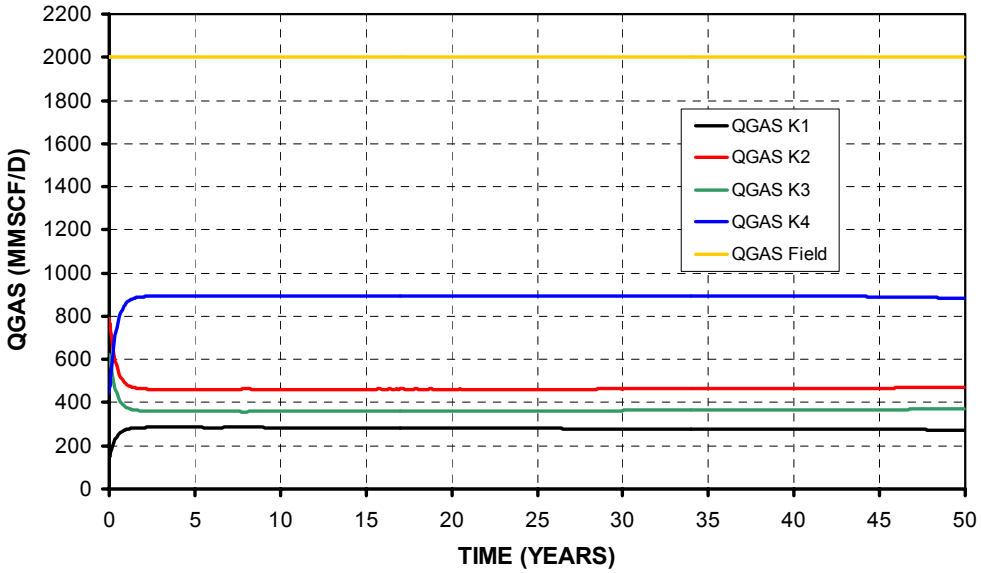

Fig. 9 – North Field Simulated Gas Production Rate

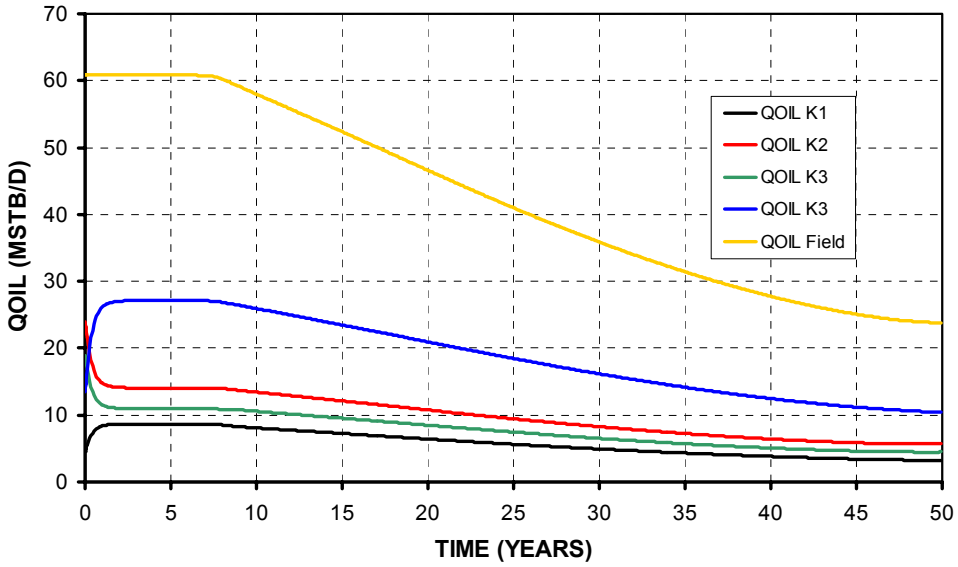

Fig. 10 – North Field Simulated Condensate Production Rate

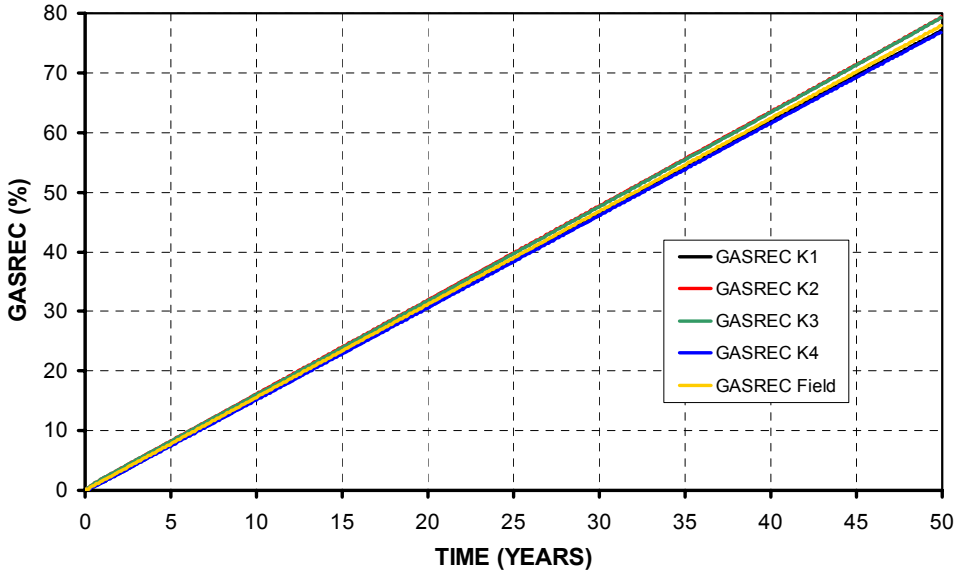

Fig. 11 – North Field Simulated Gas Recovery

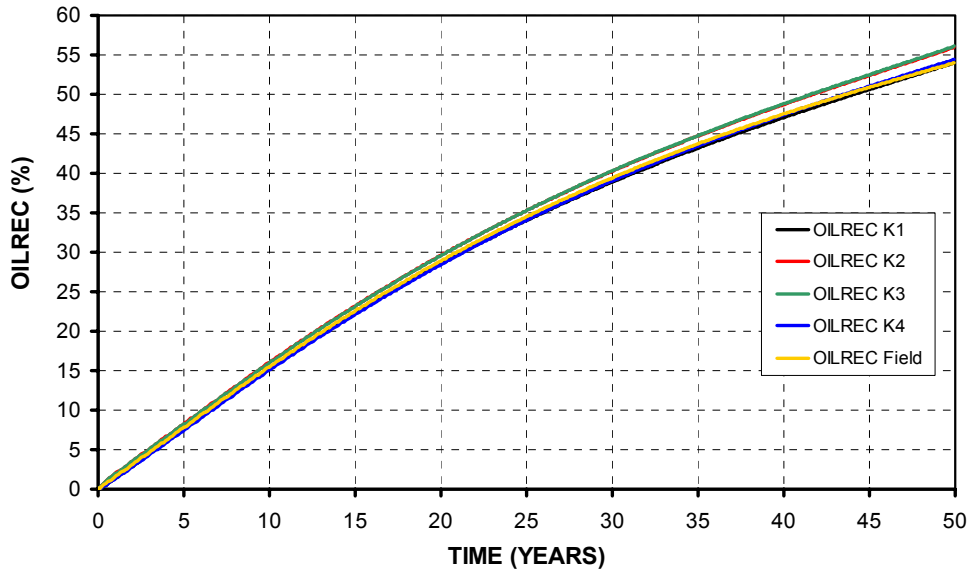

Fig. 12 – North Field Simulated Condensate Recovery

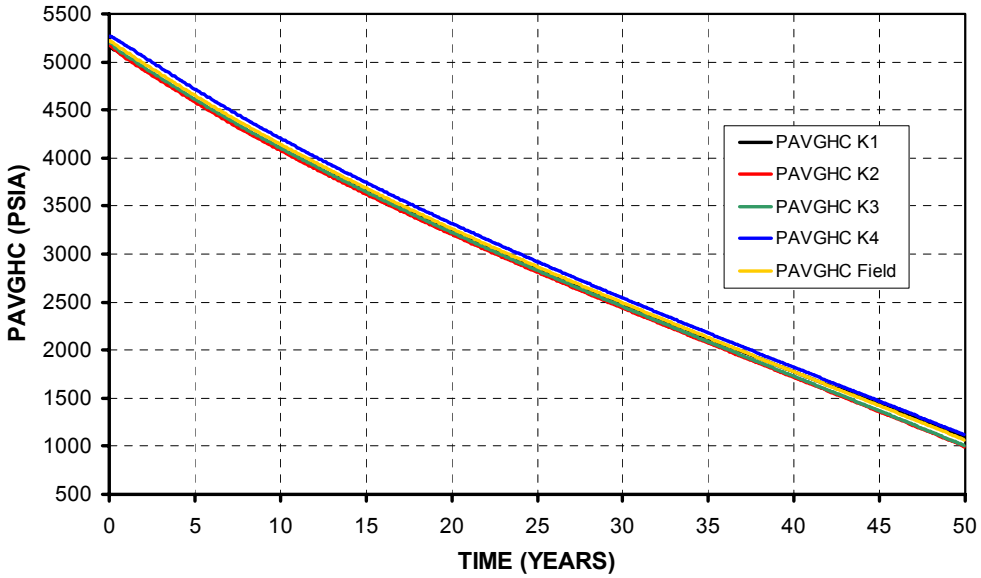

Fig. 13 – North Field Simulated Average Pressure Depletion

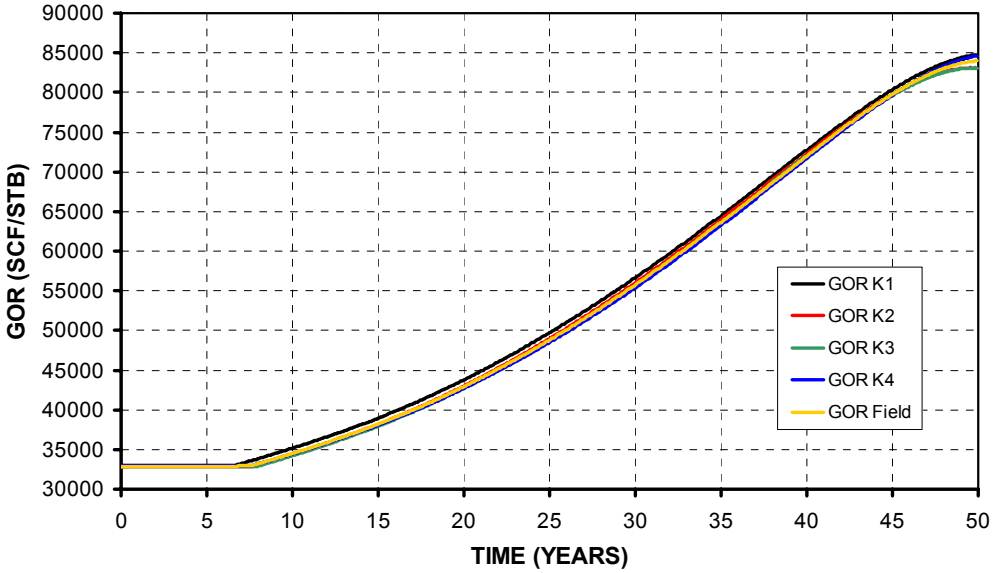

Fig. 14 – North Field Simulated Gas Oil Ratio

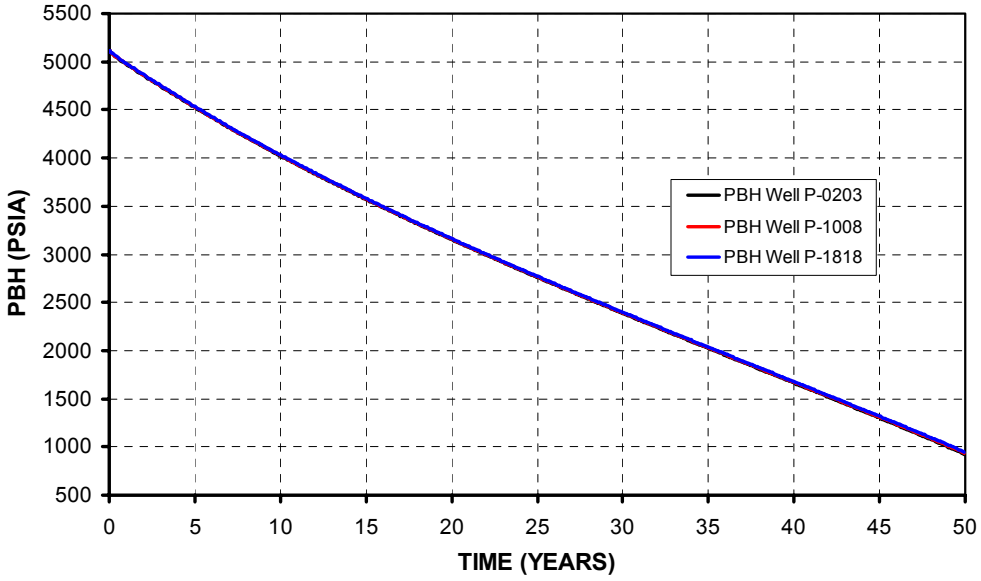

Fig. 15 – North Field Simulated Bottom Hole Pressure of some production wells

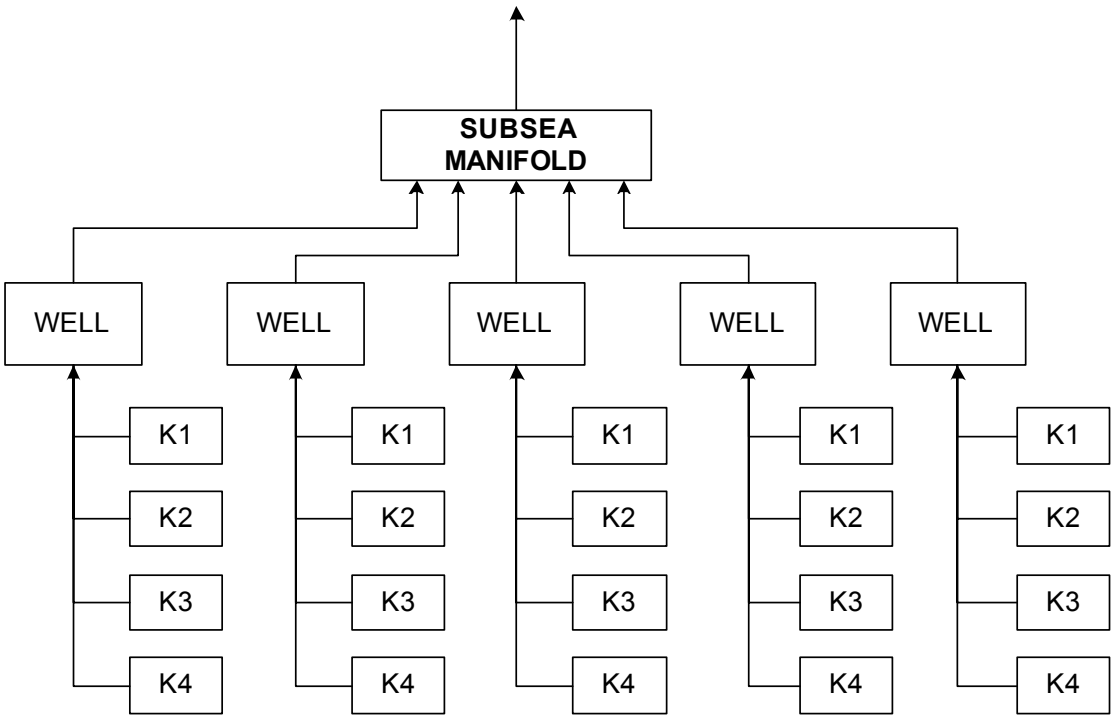

Fig. 16 – Production lining system from well connection level to sub sea manifold level

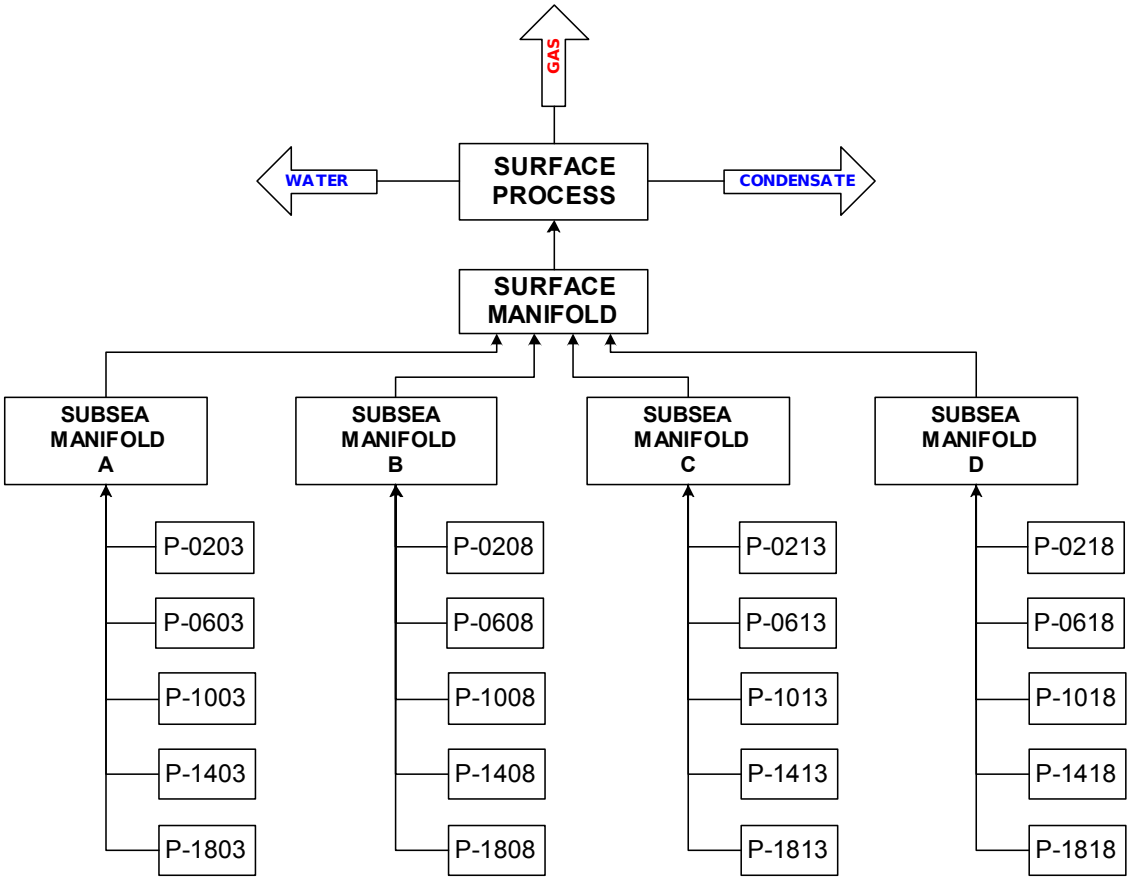

Fig. 17 – Production lining system from well level to surface process level

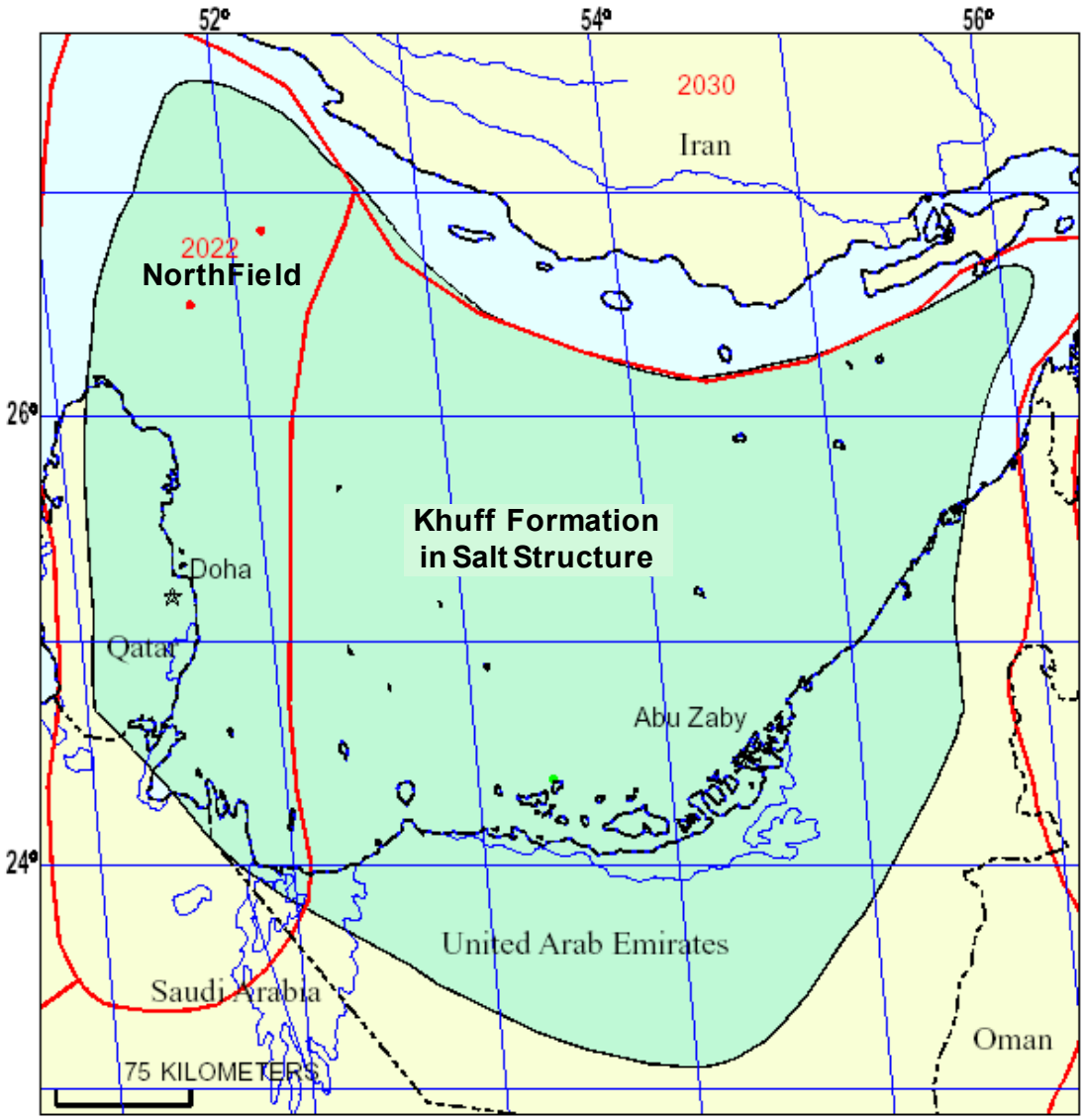

Fig. 18 – Khuff Formation and North Field Map

Appendix A
Example of *PhazeComp* files

Input file of C_{7+} Characterization and EOS model matching

```
Title   "North Field Compositional Characterization"
Title   "Initial Composition Prediction"
Title   "October 2003"

-- Input characterization for reading compositions through C7+.

CHAR "INPUT-C7+"
EOS SRK
NAME       MW
N2
CO2
H2S
C1
C2
C3
i-C4
n-C4
i-C5
n-C5
C6
C7+

END; of characterization.

-- Source of composition data: SPE 13715.
MIX NFCVDGas MOLES
N2       3.36
CO2      1.76
H2S      0.53
C1      83.51
C2       5.17
C3       1.91
i-C4     0.41
n-C4     0.70
i-C5     0.28
n-C5     0.28
C6       0.39
C7+      1.70

VARIABLE ADJ-C7+ 0.0 -0.3 0.3
INCREASE MOLES of C7+ in NFCVDGas by ADJ-C7+

-- Set up the C7+ split.
-- Use exponential (knowing nothing else).

VARIABLE CF = 0.29 0.27 0.32
REPLACE SOREIDE FACTOR by CF
SOREIDE ; to estimate SGs of the C7+ fractions.

-------------------------------------------------------------------------------
-- The Gamma model used to define SCN and C30+ MWs and properties uses
-- the (unknown) reservoir condensate C7+ and not the original reservoir
-- gas C7+. This will help improve the description of reservoir and surface
-- condensate because of a more realistic liquid-like C30+ pseudo,
-- without affecting adversely the description of reservoir gas which has
-- very little amount of the C30+ pseudo.
```

```
--------------------------------------------------------------------------------
VARIABLE MW7+ 200 250
REPLACE GAMMA AVERAGE by MW7+

GAMMA
  SPLIT C7+ C7
  SHAPE     1
  BOUND    88
END

CHAR "SRK-SCN-C30+"
EOS SRK
NAME     LMW  MW  TC(R)  PC(PSIA)  AF  VSHIFT  TB(R)  SG  ZC  ZCVIS
N2
CO2
H2S
C1
C2
C3
i-C4
n-C4
i-C5
n-C5
C6
C7
C8
C9
C10
C11
C12
C13
C14
C15
C16
C17-19
C20-29
C30+

NAME     TC(K)  PC(BAR)  TB(K)  TB(R)  PARACHOR  AMOD  BMOD  A  B

BIPS     N2     CO2     H2S
H2S     0.12    0.12   0.08
C1      0.02    0.12   0.07
C2      0.06    0.15   0.06
C3      0.08

REPLACE BIPS N2  with I-C4 to C30+ by 0.08
REPLACE BIPS CO2 with C3   to C30+ by 0.15
REPLACE BIPS H2S with C3   to N-C5 by 0.06
REPLACE BIPS H2S with C6   to C6   by 0.05
REPLACE BIPS H2S with C7   to C30+ by 0.03

VARIABLE B1-30 0.0 0.1
REPLACE BIP of C1 with C30+ by B1-30

VARIABLE TB30 900 850
REPLACE TB of C30+ by TB30 F

END; of characterization.

LUMP C7+ C7 13*1

VARIABLE GMW 132 130 145
```

```
REPLACE GAMMA AVERAGE by GMW

-- Convert the input gas composition to the extended characterization.

MIX NFCVDGas-Ext: 100 MOLES NFCVDGas

-- Fit dewpoint of lab-depleted CVD gas with 4759 dewpoint.

MIX FEED: NFCVDGas-Ext
TEMP  220 F, PRES 4759 PSIG
EXPAND @ DEWP (WT = 20), ID "Dewpoint of CVD-depleted gas at 4759 psig."
FLASH; to display saturated equilibrium.

MIX IncipOil: EQL; save the incipient liquid phase composition.

-- Create the original gas condensate with Pd=5120 psig.
-- Add incipient oil from 4759 psig CVD gas dewpoint to raise dewpoint to 5120.

VARIABLE OilFrac = 0 1
MULTIPLY MOLES of N2 to C30+ in IncipOil by OilFrac
MIX NFGas: 1 TANK IncipOil, 1 TMOLE NFCVDGas-Ext

-- Constant Volume Depletion Experiment at 220 F
-- Comparing the results with SPE data

MIX FEED: NFGas
TEMP 220 F     ; reference temperature.
PSAT           ; for displaying the saturated equilibrium.
PRES 5120 PSIG ; reference pressure.
CVD @ DEWP (WT = 20), ID "Constant Volume Depletion at at 220 F"
BASIS 1 MOLE
PRESSURE   LVF2  RMREM GMW-C7+  GZ   LMW-C7+
PSIG         %     %
5120       0.00  0.00    136   1.03
4759       0.14  4.54    132   1.00
4426       0.37  8.95    128   0.98
4051       0.82 14.62    125   0.96
3678       1.24 24.44    122   0.935
3244       1.79 28.14    119   0.925
2737       2.15 38.26    115   0.915
2314       2.31 47.52    112   0.915
1905       2.40 56.76    111   0.92
1468       2.37 66.87    110   0.93
968        2.21 78.31    109   0.95
550        2.02 87.53    109   0.97
WT           2     1      2      1

PRESSURE    Y-N2   Y-CO2  Y-H2S  Y-C1   Y-C2   Y-C3   Y-I-C4 Y-N-C4 Y-I-C5 Y-N-
C5 Y-C6   Y-C7+
PSIG           %      %      %      %      %      %      %      %      %      %
%      %
4759        3.36   1.76   0.53  83.51   5.17   1.91   0.41   0.70   0.28   0.28
0.39   1.70
3244        3.22   1.76   0.53  84.94   5.12   1.84   0.36   0.65   0.26   0.24
0.31   0.77
WT             0      0      0      0      0      0      0      0      0      0
0      1

END ; of CVD

MIX NF-K2K3: 1 MOLE NFGas
INCREASE MOLES of H2S in NF-K2K3 by 0.025
DECREASE MOLES of C1  in NF-K2K3 by 0.025
```

```
MIX FEED NF-K2K3
TEMP 220 F
PSAT


Note: "Use retrograde condensate properties at 2500 psia to get Rs and API"
Note: "for estimating viscosity of retrograde condensate with correlations."

MIX FEED NFGas
Pres 2500 psia, Temp 220 F, Flash
Mix NFRC-2500 EQL
Mix Feed NFRC-2500
DLE ID "Sep. test of retrograde condensate at 2500 psia"
STAGE  TEMP  PRES    CUMGOR   API   LVIS
         F   psia    scf/bbl        cp
  1     220  2500
  2     100   500
  3      60   14.7
End

EOF
```

Input files of Condensate viscosity matching

```
Title   "North Field Compositional Characterization"
Title   "Condensate Viscosity Fitting"
Title   "October 2003"


Note : " All variables used in the regression are taken from the initial
composition prediction simulation "
Note : " Introducing Zcvismod to fit the condensate viscosity "
Note : " Initial ZCVIS are calculated using correlation "

-- Input characterization for reading compositions through C7+.

CHAR "INPUT-C7+"
EOS SRK
NAME       MW
N2
CO2
H2S
C1
C2
C3
i-C4
n-C4
i-C5
n-C5
C6
C7+

END; of characterization.

-- Source of composition data: SPE 13715.
MIX NFCVDGas MOLES
N2       3.36
CO2      1.76
H2S      0.53
C1      83.51
C2       5.17
```

```
C3       1.91
i-C4     0.41
n-C4     0.70
i-C5     0.28
n-C5     0.28
C6       0.39
C7+      1.70

VARIABLE ADJ-C7+  2.46499e-01 ;0.0 -0.3 0.3
INCREASE MOLES of C7+ in NFCVDGas by ADJ-C7+

-- Set up the C7+ split.
-- Use exponential (knowing nothing else).

VARIABLE CF = 2.90805e-01 ; 0.29 0.27 0.32
REPLACE SOREIDE FACTOR by CF
SOREIDE ; to estimate SGs of the C7+ fractions.

-------------------------------------------------------------------------------
-- The Gamma model used to define SCN and C30+ MWs and properties uses
-- the (unknown) reservoir condensate C7+ and not the original reservoir
-- gas C7+. This will help improve the description of reservoir and surface
-- condensate because of a more realistic liquid-like C30+ pseudo,
-- without affecting adversely the description of reservoir gas which has
-- very little amount of the C30+ pseudo.
-------------------------------------------------------------------------------
VARIABLE MW7+ 200 ; 250
REPLACE GAMMA AVERAGE by MW7+

GAMMA
  SPLIT C7+ C7
  SHAPE     1
  BOUND    88
END

CHAR "SRK-SCN-C30+"
EOS SRK
NAME     LMW  MW  TC(R)  PC(PSIA)  AF  VSHIFT  TB(R)  SG  ZC   ZCVIS
N2
CO2
H2S
C1
C2
C3
i-C4
n-C4
i-C5
n-C5
C6
C7
C8
C9
C10
C11
C12
C13
C14
C15
C16
C17-19
C20-29
C30+
```

```
NAME     TC(K)  PC(BAR)  TB(K)  TB(R)  PARACHOR  AMOD  BMOD  A  B

BIPS     N2     CO2     H2S
H2S     0.12    0.12   0.08
C1      0.02    0.12   0.07
C2      0.06    0.15   0.06
C3      0.08

REPLACE BIPS N2  with I-C4 to C30+ by 0.08
REPLACE BIPS CO2 with C3   to C30+ by 0.15
REPLACE BIPS H2S with C3   to N-C5 by 0.06
REPLACE BIPS H2S with C6   to C6   by 0.05
REPLACE BIPS H2S with C7   to C30+ by 0.03

VARIABLE B1-30 6.88655e-02 ; 0.0 0.1
REPLACE BIP of C1 with C30+ by B1-30

VARIABLE TB30 850 ; 900 850
REPLACE TB of C30+ by TB30 F

CORRELATE ; to get other parameters haven't been defined initially

VARIABLE Zcvismod =  0 -1 1
DECREASE ZCVIS of C7 to C30+ by 0.265
MULTIPLY ZCVIS of C7 to C30+ by Zcvismod
INCREASE ZCVIS of C7 to C30+ by 0.265

END; of characterization.

LUMP C7+ C7 13*1

VARIABLE GMW 1.35162e+02 ; 132 130 145
REPLACE GAMMA AVERAGE by GMW

-- Convert the input gas composition to the extended characterization.

MIX NFCVDGas-Ext: 100 MOLES NFCVDGas

-- Fit dewpoint of lab-depleted CVD gas with 4759 dewpoint.

MIX FEED: NFCVDGas-Ext
TEMP  220 F, PRES 4759 PSIG
EXPAND @ DEWP (WT = 20), ID "Dewpoint of CVD-depleted gas at 4759 psig."
FLASH; to display saturated equilibrium.

MIX IncipOil: EQL; save the incipient liquid phase composition.

-- Create the original gas condensate with Pd=5120 psig.
-- Add incipient oil from 4759 psig CVD gas dewpoint to raise dewpoint to 5120.

VARIABLE OilFrac = 1.48224e-03 ; 0 1
MULTIPLY MOLES of N2 to C30+ in IncipOil by OilFrac
MIX NFGas: 1 TANK IncipOil, 1 TMOLE NFCVDGas-Ext

-- Constant Volume Depletion Experiment at 220 F
-- Comparing the results with SPE data

MIX FEED: NFGas
TEMP 220 F     ; reference temperature.
PSAT           ; for displaying the saturated equilibrium.
PRES 5120 PSIG ; reference pressure.
CVD @ DEWP (WT = 20), ID "Constant Volume Depletion at at 220 F"
BASIS 1 MOLE
```

```
PRESSURE   LVF2  RMREM GMW-C7+  GZ   LMW-C7+
PSIG         %     %
5120       0.00  0.00    136   1.03
4759       0.14  4.54    132   1.00
4426       0.37  8.95    128   0.98
4051       0.82 14.62    125   0.96
3678       1.24 24.44    122   0.935
3244       1.79 28.14    119   0.925
2737       2.15 38.26    115   0.915
2314       2.31 47.52    112   0.915
1905       2.40 56.76    111   0.92
1468       2.37 66.87    110   0.93
968        2.21 78.31    109   0.95
550        2.02 87.53    109   0.97
WT           2     1      2      1

PRESSURE    Y-N2   Y-CO2  Y-H2S  Y-C1   Y-C2   Y-C3   Y-I-C4 Y-N-C4 Y-I-C5 Y-N-
C5 Y-C6   Y-C7+
PSIG          %      %      %      %      %      %      %      %      %      %
%      %
4759        3.36   1.76   0.53  83.51   5.17   1.91   0.41   0.70   0.28   0.28
0.39   1.70
3244        3.22   1.76   0.53  84.94   5.12   1.84   0.36   0.65   0.26   0.24
0.31   0.77
WT            0      0      0      0      0      0      0      0      0      0
0      1

END ; of CVD


MIX NF-K2K3: 1 MOLE NFGas
INCREASE MOLES of H2S in NF-K2K3 by 0.025
DECREASE MOLES of C1  in NF-K2K3 by 0.025

MIX FEED NF-K2K3
TEMP 220 F
PSAT


Note: "Use retrograde condensate properties at 2500 psia to get Rs and API"
Note: "for estimating viscosity of retrograde condensate with correlations."

-- Expected CUMGOR and API @ surface are taken from the initial composition
prediction simulation
-- VISO@surface ( API = 44.111 , T = 220 F) = 0.8 cp ....(Properties Data Book
(Yellow Book))
-- Expected VISO @ 2500 psia ( VISO@surface = 0.8 cp, GOR = 743.55 scf/bbl) =
0.34 cp ....(Properties Data Book (Yellow Book))

MIX FEED NFGas

Pres 2500 psia, Temp 220 F, Flash
Mix NFRC-2500 EQL
Mix Feed NFRC-2500
DLE ID "Sep. test of retrograde condensate at 2500 psia"
STAGE  TEMP  PRES    CUMGOR     API        LVIS
         F   psia    scf/bbl               cp
  1     220  2500                          0.34
  2     100   500
  3      60   14.7    743.55    44.111
```

```
End

EOF
```

Appendix B
Example of *Sensor* input file of North Field reservoir model

```
TITLE
       North Field Full Field Cartesian Model
       Covering area of 100 sq.km with 4 major layers K1, K2, K3 and K4
       Gridding System : 20x20x17 = 5200 active blocks with 4 isolation layers
       Compositional Simulation with EOS30+ model
       20 gas production wells
       Swi=0.2 and porosity=0.15
       20 production wells are open since beginning, 50 years of simulation
       Arif Kuntadi
       30-10-2003
ENDTITLE

RUN
GRID  20    20    17
CPU

MAPSPRINT 1 PV DELX DELY DEPTH POROS KX KY KZ TZ PSAT SG SW P

C Grid file
C 20x20x17 Full Field Grid Model
C There are 4 main layers : K1 K2, K3 and K4
C Each layer is separated by isolation layer
C K1 is divided into 3 sublayers
C K2 is divided into 3 sublayers
C K3 is divided into 3 sublayers
C K4 is divided into 4 sublayers
C The main layers are set up as regions

REGION   CON
    0
MOD
C   I1   I2    J1   J2       K1   K2

    1    20    1    20    1     3    = 1
    1    20    1    20    5     7    = 2
    1    20    1    20    9     11   = 3
    1    20    1    20    13    16   = 4
REGNAME
  1  K1-Zone
  2  K2-Zone
  3  K3-Zone
  4  K4-Zone

C Layer K1 and K4 are using the PVTTYPE 1
C Layer K2 and K3 are using the PVTTYPE 1
C All layers are using the same PVTTYPE but different initial gas composition

PVTTYPE CON
   1
C MOD
C   I1   I2    J1   J2       K1   K2
C    1    20    1    20    5     7    = 2
```

```
C    1    20    1    20    9     11   = 2

C Area is assumed as 10 km x 10 km
C DX=DY=1640.42 ft, 500 meters in the reservoir zone

C K1 layer has thickness of 204.08 ft
C DZ=68.03 ft for layer 1 - 3 ( Region K1)
C DZ=3.28 ft for layer 4 (isolation layer between K1 and K2)

C K2 layer has thickness of 326.53 ft
C DZ=108.84 ft for layer 5 - 7 ( Region K2)
C DZ=3.28 ft for layer 8 (isolation layer between K2 and K3)

C K3 layer has thickness of 255.10 ft
C DZ=85.03 ft for layer 9 - 11 ( Region K3)
C DZ=142.86 ft for layer 12 (isolation layer between K3 and K4)

C K4 layer has thickness of 642.86 ft
C DZ=160.71 ft for layer 13 - 16 ( Region K4)
C DZ=142.86 ft for layer 17 (bottom isolation layer)

DELX  CON
  1640.42 ! 500 m

DELY  CON
  1640.42 ! 500 m

THICKNESS ZVAR
  3*68.03     ! K1
  3.28        ! Isolation layer
  3*108.84    ! K2
  3.28        ! Isolation layer
  3*85.03     ! K3
  142.86      ! Isolation layer
  4*160.71    ! K4
  142.86      ! Isolation layer

C Constant depth to the top surface of the reservoir
DEPTH  CON
 8050 ! ft

C The permeability range of Khuff Formation is 3 -  1800 mD with the average of
30 mD
C K1 and K4 have low permeability, lower than K2 and K3
C K2 and K3 have almost the same permeability
C K1 layer with 3 sublayers, is initially assigned uniform permeability
C K2 layer with 3 sublayers, is initially assigned uniform permeability
C K3 layer with 3 sublayers, is initially assigned uniform permeability
C K4 layer with 4 sublayers, is initially assigned uniform permeability


KX   ZVAR
  3*30        ! K1
  0           ! Isolation layer
  3*100             ! K2
  0           ! Isolation layer
  3*100             ! K3
  0           ! Isolation layer
  4*30              ! K4
  0           ! Isolation layer

C  Assuming KY and KZ are equal to KX
```

```
KY   EQUALS KX

KZ   EQUALS KX * 0.1

C The porosity is set uniform for K1, K2, K3 and K4

POROS ZVAR
  3*0.15      ! K1
  0           ! Isolation layer
  3*0.15      ! K2
  0           ! Isolation layer
  3*0.15      ! K3
  0           ! Isolation layer
  4*0.15      ! K4
  0           ! Isolation layer

C -----------------------------------------

C define Initialization Regions
C IR 1 for K1 and K4 regions
C IR 2 for K2 and K3 regions

  INITREG     CON
      0
  MOD
C   I1   I2    J1   J2      K1    K2
    1    20    1    20    1       3    = 1
    1    20    1    20    5       7    = 2
    1    20    1    20    9       11   = 2
    1    20    1    20    13      16   = 1


C Pref and water and rock properties
C The water has salinity 73 ppm NaCl
C     Bwi     cw            denw       visw     cr       Pref
MISC  1.0375  2.635E-6      62.36923   0.65     5E-6     5300


C EOS30+Model for All Layers
C North Field EOS30+ MODEL

PVTEOS SRK 1

C reservoir temperature, F
220.0

C Fluid characterization, 24-components SRK-EOS

CPT    MW      TC           PC            AC     OMEGA  OMEGB         SHIFT   ZCRIT
       PCHOR
N2     28.014  227.160      492.840              0.0370 0.42748       0.0866403
       -0.0009        0.29178       59.10
CO2    44.010  547.420      1069.510      0.2250 0.42748       0.0866403
       0.21749        0.27433       80.00
H2S    34.082  672.120      1299.970      0.0900 0.42748       0.0866403
       0.10153        0.28292       80.10
C1     16.043  343.010      667.030              0.0110 0.42748       0.0866403
       -0.00247 0.28620      71.00
C2     30.070  549.580      706.620              0.0990 0.42748       0.0866403
       0.05894        0.27924       111.00
C3     44.097  665.690      616.120              0.1520 0.42748       0.0866403
       0.09075        0.27630       151.00
```

```
i-C4   58.123  734.130     527.940             0.1860 0.42748       0.0866403
       0.10952       0.28199      188.80
n-C4   58.123  765.220     550.560             0.2000 0.42748       0.0866403
       0.11028       0.27385      191.00
i-C5   72.150  828.700     490.370             0.2290 0.42748       0.0866403
       0.09773       0.27231      227.40
n-C5   72.150  845.460     488.780             0.2520 0.42748       0.0866403
       0.11947       0.26837      231.00
C6     82.319  924.210     491.320             0.2373 0.42748       0.0866403
       0.13411       0.27034      232.57
C7     95.357  988.340     457.180             0.2714 0.42748       0.0866403
       0.14292       0.26496      263.86
C8     108.772       1043.920    422.820             0.3094 0.42748
       0.0866403    0.15223       0.26516      296.05
C9     121.895       1094.090    389.970             0.3500 0.42748
       0.0866403    0.1697  0.26535      327.55
C10    134.784       1138.550    361.660             0.3900 0.42748
       0.0866403    0.18619       0.26553      358.48
C11    147.589       1178.850    336.960             0.4295 0.42748
       0.0866403    0.20181       0.26568      389.21
C12    160.302       1215.630    315.310             0.4684 0.42748
       0.0866403    0.2165  0.26583      419.72
C13    172.914       1249.410    296.270             0.5067 0.42748
       0.0866403    0.23022       0.26597      449.99
C14    185.422       1280.570    279.430             0.5444 0.42748
       0.0866403    0.24298       0.26610      480.01
C15    197.823       1309.450    264.480             0.5814 0.42748
       0.0866403    0.25481       0.26623      509.77
C16    210.113       1336.330    251.140             0.6178 0.42748
       0.0866403    0.26573       0.26636      539.27
C17-19 233.389       1383.110    229.290             0.6857 0.42748
       0.0866403    0.28431       0.26659      595.13
C20-29 299.514       1493.680    184.610             0.8712 0.42748
       0.0866403    0.32394       0.26721      753.83
C30+   477.341       1616.940    167.560             1.0411 0.42748
       0.0866403    0.11537       0.26767      1180.62


BIN

2*0.0  0.12   0.02   0.06   19*0.08
2*0.0  2*0.12 20*0.15
2*0.12 0.0    0.07   6*0.06 0.05   13*0.03
0.02   0.12   0.07   20*0.0 0.06887
0.06   0.15   0.06   21*0.0
0.08   0.15   0.06   21*0.0
0.08   0.15   0.06   21*0.0
0.08   0.15   0.06   21*0.0
0.08   0.15   0.06   21*0.0
0.08   0.15   0.06   21*0.0
0.08   0.15   0.05   21*0.0
0.08   0.15   0.03   21*0.0
0.08   0.15   0.03   21*0.0
0.08   0.15   0.03   21*0.0
0.08   0.15   0.03   21*0.0
0.08   0.15   0.03   21*0.0
0.08   0.15   0.03   21*0.0
0.08   0.15   0.03   21*0.0
0.08   0.15   0.03   21*0.0
0.08   0.15   0.03   21*0.0
0.08   0.15   0.03   21*0.0
0.08   0.15   0.03   0.06887      20*0.0
```

```
SEP 1     ! separator conditions are the same as in the PERA-EOS
C       P (psia)      T (F)
       1000          80
       350           70
        14.7          60

C Initialization for a compositional run

C Initialization of K1 and K4 zone

INITIAL  1
  DEPTH    ! Dew Point Press   Initial gas composition
  9600    5120
  0.03349140
  0.01755249
  0.00528997
  0.83265138
  0.05157940
  0.01906559
  0.00409428
  0.00699227
  0.00279855
  0.00279921
  0.00390314
  0.00486066
  0.00360525
  0.00265690
  0.00201386
  0.00152830
  0.00116200
  0.00088551
  0.00067654
  0.00051834
  0.00039836
  0.00072976
  0.00062968
  0.00011715

PINIT   5300
ZINIT   9600

C Initialization of K2 and K3 zone

INITIAL  2
  DEPTH    ! Dew Point Press   Initial gas composition
  8500    4930
  0.033491
  0.017552
  0.030290
  0.807651
  0.051579
  0.019066
  0.004094
  0.006992
  0.002799
  0.002799
  0.003903
  0.004861
  0.003605
  0.002657
  0.002014
```

```
  0.001528
  0.001162
  0.000886
  0.000677
  0.000518
  0.000398
  0.000730
  0.000630
  0.000117

PINIT   5180
ZINIT   8500

C Relative Perms
C Two-phase water-oil saturation table
C Swi=0.2
C Water is wetting phase

KRANALYTICAL
.2 .2 .2 .1   ! swc sorw sorg sgc
 .5  .33  .9 ! krwro krgro krocw
 3  3  3  3   ! nw now ng nog

ENDINIT

PSM

C ------------------------- Recurrent Data -----------------------------
C  Well data
C  There are 20 production wells
C  Wells are producing from all layers

WELL
            I     J      K1     K2       ! header line   calculate well indices
internally

 P-0203     2     3      1      3
            2     3      5      7
            2     3      9      11
            2     3      13     16

 P-0208     2     8      1      3
            2     8      5      7
            2     8      9      11
            2     8      13     16

 P-0213     2     13     1      3
            2     13     5      7
            2     13     9      11
            2     13     13     16

 P-0218     2     18     1      3
            2     18     5      7
            2     18     9      11
            2     18     13     16

 P-0603     6     3      1      3
            6     3      5      7
            6     3      9      11
            6     3      13     16

 P-0608     6     8      1      3
            6     8      5      7
```

	6	8	9	11
	6	8	13	16
P-0613	6	13	1	3
	6	13	5	7
	6	13	9	11
	6	13	13	16
P-0618	6	18	1	3
	6	18	5	7
	6	18	9	11
	6	18	13	16
P-1003	10	3	1	3
	10	3	5	7
	10	3	9	11
	10	3	13	16
P-1008	10	8	1	3
	10	8	5	7
	10	8	9	11
	10	8	13	16
P-1013	10	13	1	3
	10	13	5	7
	10	13	9	11
	10	13	13	16
P-1018	10	18	1	3
	10	18	5	7
	10	18	9	11
	10	18	13	16
P-1403	14	3	1	3
	14	3	5	7
	14	3	9	11
	14	3	13	16
P-1408	14	8	1	3
	14	8	5	7
	14	8	9	11
	14	8	13	16
P-1413	14	13	1	3
	14	13	5	7
	14	13	9	11
	14	13	13	16
P-1418	14	18	1	3
	14	18	5	7
	14	18	9	11
	14	18	13	16
P-1803	18	3	1	3
	18	3	5	7
	18	3	9	11
	18	3	13	16
P-1808	18	8	1	3
	18	8	5	7
	18	8	9	11
	18	8	13	16

```
 P-1813     18   13    1     3
            18   13    5     7
            18   13    9     11
            18   13    13    16

 P-1818     18   18    1     3
            18   18    5     7
            18   18    9     11
            18   18    13    16


WELLTYPE
  P-0203 -  P-1818    MCF  !   gas producer, Mscf/D

WELLPLAT  ! assign wells to a particular platform
 -1        1       ! Assign all gas wells to platform 1
                   ! "-1" means all producers

C Define field production target rate
C The Field Target Rate is 2000 MMSCF/D

  PTARG  1   G   2e6   ! Field plateau rate, MCF/D

C Initially all 20 wells are open for production
C Each well has production rate of 100 MMSCF/D

RATE
 P-0203 - P-1818     100000      ! MCF/D target rate

WELLSUM
    -1     1  ! output summary for all producers

PLATSUM
   -1    0    ! print out platform summary for all timesteps

TIME   365
TIME   1825
TIME   3650
TIME   5475
TIME   7300
TIME   9125
TIME   10950
TIME   12775
TIME   14600
TIME   16425
TIME   18250

END
```