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Application of EOS to Optimize the Design of an Early Production Scheme of an Onshore Oil Field in Abu Dhabi

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Abstract

This study is aimed at optimizing the design of surface facilities of an early production scheme for an onshore Abu Dhabi oil field. The current design of separation facilities is modular, and thus improvements in performance are possible with a better understanding of PVT properties of the oil produced. This is performed by optimizing the multistage separator process for the range of properties of oil processed by the facilities.

This paper describes the characterization of the crude oil processed by the facility using the 3-parameter Peng-Robinson Equations of state to describe the phase behavior and fluid properties using reservoir fluid data and an analysis of production data. After characterizing the fluids from each production well in the reservoir, the streams are mixed and the overall characterization of the total reservoir crude oil is used to optimize the design of the current

facilities. This overall characterization of the crude oil is checked and compared to field analysis from the current operating facility.

Current production facilities consist of one production separator followed by a free water knockout tank. Results show that optimum separation requires a multi-stage scheme versus the two-stage scheme being used now. Up to 2-3 % increase in oil volumes produced may be achieved by using an optimized 3-stage separator design consisting of high and medium pressure production separators followed by the free water knockout tank.

Introduction

ADCO Field in Brief. Abu Dhabi Company for Onshore Oil Operations (ADCO) operates an onshore early production facility in to gather well test production data and assess reservoir performance that will allow ADCO to evaluate the potential for full-scale development of the field. Following the commissioning, several differences from the design basis were recognized in the produced fluids that would require modification of production strategy. This process is continuing as ADCO gains more operating experience about the fields.

Reservoir Description. Hydrocarbon deposits are encountered in three zones (A, B, C). Zones 'A' & 'C' contain gas with the possibility of an oil rim while Zone 'B' contains undersaturated oil in a very tight

formation (1-3 md). High levels of H_2S are encountered in Zone 'C'. Development of Zone 'B' is being considered, and an Early Production Scheme (EPS) is presently ongoing to gather dynamic and static reservoir information. Currently the reservoir is producing from seven wells with an overall production rate of 4,000 – 7,000 bopd.

A total of 9 wells (W-1 to W-9) have been drilled up to date, of which W-8 is a water disposal well in a shallower formation. Fig.1 shows the producing thickness for each well. The early wells were mostly completed with dual strings, i.e. one for Zone 'B' (short) and one for Zone 'C' (long). Communication between the strings influenced the data gathering considerably. During the recent few months, most wells have been worked over as single horizontal completions in the top of the Zone 'B' layer. Numerous bottom hole samples have been taken over the years and a significant variation in reservoir fluid PVT parameters has been measured; in particular in the bubble point and solution gas-oil ratio. Various suggestions have been made to explain this variation in PVT characteristics. These include:

- a) Compositional grading versus depth and variation of composition over the field area due to compartmentalization.
- b) Gas cusping from a possible gas cap in the crest of zone 'B'.
- c) Gas influx via mechanical communication from zones 'A' and/or 'C'.
- d) Oil blockage due to the dynamic behavior of oil and gas phases.
- e) Oil migration aspects and differences in source rock.

Studies so far have been inconclusive in identifying the reasons for variations in PVT properties.

Gathering System. Fig. 2 is schematic diagram of the flow line network. Individual flowlines from Wells W-1, W-3 and the combined offshore flowlines (12 inches) from offshore wells W-2, W-4, W-5, W-6, and W-9 arrive at the production manifold located at CPP. At the manifold, W-1 and W-3 flowlines can be routed to a production header, test header or blowdown header, while the 12" offshore flow lines can be routed to either a production header or blowdown header, because these offshore wells were tested on site using a mobile test separator.

Central Processing Plant (CPP).

Oil/Water facilities: Fig. 3 is a schematic diagram of the plant facilities. The process consists of two three-phase separators, one for production and the other for testing. The production separator operates at 60 psig. The crude from the production separator goes into the free water knock out (FWKO) tank, which is of gun barrel configuration. FWKO tank operates on LP flare system back pressure. The oil from FWKO tank is metered and pumped via a transfer line.

A Corrugated Plate Interceptor (CPI) unit is used to treat the produced water, which is injected afterwards into underground formation.

Gas Facilities. The high gas flow rates from the production separator make it attractive to process the gas by compression, dehydration, and dew-point depression prior to its export to gas pipeline. Gas leaving the production separator is the source of both sales gas and fuel gas. Fuel gas for plant operation is fed to a fuel gas scrubber prior to its being used at the power plant. Sales gas enters two 5 MMSCFD capacity reciprocating compressors. Both compressors have two stages of compression, with each stage having a suction knockout drum and discharge air cooler. These compressors have gas-driven engines.

Leaving the compressor skid, the combined flow of sales gas from each unit is further cooled in a heat exchanger using recycled condensed liquids from the refrigeration unit. The cooled and compressed gas enters a knockout drum, where condensed water and hydrocarbon liquids separate, and gas then enters the glycol contactor. In the glycol unit, the water is removed with triethylene glycol at 32 °F to meet sales gas specifications of 7 lb water/MMSCF.

Sales gas enters the Dew Point Depression unit (DPD) where gas condensates are removed prior to their shipping to export line. The DPD unit consists of a heat exchanger where gas is pre-cooled using refrigerated sales gas. Gas is then chilled to 41°F in a refrigeration unit using vaporizing propane as refrigerant. This gas is reheated in the heat exchanger. Propane compressor for the refrigeration unit is gas engine driven. Condensed liquids are heated against compressed gas, metered, sent to a flash drum, and routed to the production separator. Vapors from the flash drum are flared.

Literature Review

Relevant considerations for two and three phase flash separation are briefly reviewed below.

Flash Separation Equations. A flash is a single stage distillation in which a feed is partially vaporized to give a vapor that is richer in the more volatile component. If the equipment is designed properly, the vapor and liquid leaving the drum will be in equilibrium. Unless the relative volatility is very large, the degree of separation achievable between two components in a single stage is poor. However, the computational methods used in single-stage calculation are of fundamental importance.

There are two types of flash, isothermal flash, and adiabatic flash. Actual flash in surface facilities has characteristics from both. Flash calculations on a two-phase system are made to establish the relative amounts of vapor and liquid resulting, and the analysis of each exiting stream.

Produced wellhead fluids are complex mixtures of hydrocarbon compounds that have different physical properties, i.e. density, vapor pressure, ...etc. The well stream undergoes continuous pressure and temperature reduction as it leaves the reservoir. Gases evolve from liquids, water vapor condenses and part of the well stream changes from a liquid to bubbles, mist and free gas. Physical separation of these phases is one of the basic operations in production, processing, and treatment of oil and gas. Oil and gas separators mechanically separate liquid and gas components that exist at a specific temperature and pressure, for eventual processing into salable items. A separator vessel normally is the initial processing vessel in any facility, and improper design of this component can bottleneck and reduce capacity of the entire facility^{1, 2, 3}. Equations describing two and three-phase flash are listed in a number of references^{4, 5}.

Estimation of K-Values. Equilibrium ratios play a fundamental role in the understanding of phase behavior of hydrocarbon mixtures. They are important in predicting compositional changes under varying temperatures and pressure conditions in reservoirs, surface separators, production, and transportation facilities.

Equilibrium ratios, more commonly known as K-values, relate the vapor mole fractions, y_i , to the liquid mole fraction, x_i , of a component i in a mixture,

$$K_i = \frac{y_i}{x_i}$$

In a fluid mixture consisting of different chemical components, K-values are dependent on mixture pressure, temperature, and composition of the mixture.

There are a number of methods for predicting K-values, basically these methods compute K-values explicitly or iteratively. The explicit methods correlate K-values with components parameters (i.e. critical properties), mixtures parameters (i.e. convergence pressure). Iterative methods are based on the equation of State (EOS) and are usually tuned.

Equations of State. Equations of state have evolved during the past century from the ideal gas law expression to modern day equation of state. The evolution is expected to continue with more capable equations of state. In general an equation of state is developed first for pure substances, then extended to mixtures by using mixing rule for combining pure component parameters. However, simple equations of state have found extremely valuable applications in phase equilibrium predictions, as demonstrated by Soave and by Peng Robinson in their modifications of the Redlich Kwong equation of state. Equations describing equations of state are reported elsewhere⁶.

Empirical Equations. Standing⁷ developed a widely used correlation for K values based on data reported by Katz and Hachmuth on recombined samples of gas and oil from the Wilcox sand of the Oklahoma city field.

Effect of Water Content on Separation. Water and hydrocarbons are natural companions. Hydrocarbons are formed in a water environment and are in equilibrium with water at reservoir conditions.

Liquid water and hydrocarbons are essentially immiscible in each other. Their slight mutual solubility is important for hydrate prediction but has no measurable effect on their vapor liquid equilibrium behavior. If both liquid water and hydrocarbons and gas are present in a system there will be two liquid phases. The amount of water vapor

in the gas is governed by its vapor pressure, and by the gas composition. Hydrocarbons are frequently produced with non-hydrocarbon impurities. The most common include water, carbon dioxide, hydrogen sulfide and nitrogen. Since water has a low vapor pressure and is virtually immiscible in the hydrocarbon liquid phase, it does not have a significant effect on the shape of the hydrocarbon phase envelope except at high temperature and low pressure^{8,9}.

Oil and water are usually separated more quickly and completely in a free water knockout tank (FWKO) where the liquid travels through the vessel in a horizontal rather than a vertical direction. Horizontal flow permits a less restricted downward movement of the water droplets. If the emulsion flows vertically upwards the water must move downward through an upward moving stream.

When the free water is removed, it may or may not be necessary to treat the oil further. In many fields producing light oil, a well designed FWKO with ample settling time and with a reasonable chemical treatment program can provide pipeline quality oil. Most often, however, further emulsion treating is required downstream of the FWKO⁷.

Optimization of separator pressure. It has long been known in the industry that increasing the number of stages in a multi-stage separation system will improve recovery in terms of barrels of oil per unit volume of the well stream. There is, of course, an economic limit to the number of stages that can be used. The first step in calculating fluid properties is the selection of separator conditions. There may be circumstances for a particular field which dictate a specific separator pressure. If not, the separator pressure which produces the maximum amount of stock tank liquid is selected. This pressure is known as optimum separator pressure. It is defined from the separator tests as the separator pressure that results in a minimum of total gas-oil ratio, a minimum in formation volume factor of oil, and a maximum in stock-tank API oil gravity⁵.

Results and Discussion

Data Sources. Data used in this study consisted of:

1. PVT laboratory reports using bottom hole samples for each well.
2. Production data measured using a test separator

for each well.

3. Compositional analysis of different streams, i.e. gas, oil for the current Early Production Scheme.

For each well, at least one representative bottom-hole sample is available with the exception of W-5, for which the bottom hole sample was considered not representative and W-7, for which no PVT laboratory test was conducted since it was used as an observation well.

Classification of Reservoir Oil Produced. Using analysis of fluid samples, fingerprint plots of all wells are presented in Fig. 4. They show that the oil produced can be classified into two groups, group I and group II.

Validation of PVT Data for Individual Wells. The validation of PVT samples was performed by comparing the producing GOR obtained from laboratory data with flow rates obtained from production test measurements conducted on-site on a monthly basis. This is necessary to ensure that the samples are representative of reservoir oil produced.

Table 1 shows a comparison of the laboratory measured solution gas oil ratios with the range of producing GOR reported for each well using test separator results. Also listed in the table are the bubble point pressures and the bottom hole pressure at the datum level 8960 ft ss Where BHT is 250 deg. F, also test separator conditions for all wells. These indicate that group I wells (consisting of wells W-1 and W-2) have a low GOR and bubble point ($P_B \approx 1600$ psia, GOR = 600-700 SCF/STB). While group II wells (consisting of W-3, W-4, W-6, and W-9) have high GOR and bubble points ($P_B = 3500-4000$ psia, GOR = 1100-1700 SCF/STB). There is no correlation of GOR or P_B with depth, indicating that layers being produced may not be continuous. They also indicate that all laboratory data are within the range observed by production tests for all wells. When the producing GOR goes over the solution GOR, this indicates free gas production due to either gas cusping or that the producing bottom hole pressure is below the bubble point pressure.

EOS Modeling of Oil Produced from Individual Wells. As a first step, all PVT measurements for each well were simulated by an EOS computer package using the 3-parameter Peng Robinson EOS. The modeling consisted of regression versus experimental PVT test until the model reproduced

the tests within a reasonable accuracy. The modeling was carried out in the steps summarized below:

i. The monophasic fluid compositions usually specified up to C_{7+} were used in the EOS package and both the differential liberation test and the separation test were simulated to determine the basic PVT parameters i.e.

- Bubble point pressure, P_b .
- Oil formation volume factor, B_o , at both initial pressure and bubble point pressure.
- Solution gas oil ratio, R_s .
- Oil density, and
- Oil viscosity at P_i & P_b

ii. Because significant deviation with the measured data existed, regression was carried out on the bubble point value using compositional data up to C_{20+} and the bubble point was matched by varying the critical temperature of C_{20+} .

iii. The next 'step' was to group $C_{12} - C_{20+}$ components into one pseudo component, i.e. C_{12+} , and again a bubble point match was obtained by varying the critical temperature of C_{12+} fraction.

iv. The grouping was then repeated for the C_{7+} fraction, i.e. $C_7 - C_{12+}$, and the bubble point experiment was again matched by varying the critical temperature of C_{7+} .

v. Further regression was applied on the C_{7+} in order to match the oil density by using the volume shift parameter, and to match the viscosity by using the critical volume parameter.

vi. After regression was carried out, differential liberation and separation tests were simulated once more with the new regressed parameters in order to compare simulated data to experimental data. Fig. 5 shows the comparison between experimental and final simulated B_o and R_s values for all wells.

Flashing of Regressed Well Mixtures and Comparison to Field Analysis. After constructing the EOS fluid model for each well, properties of the C_{7+} from this model were used in a process simulator also using the PR EOS, and the individual well streams were combined according to ratios of production of individual wells obtained from production test data. This mixture was fed, within the process simulator, into the current 2-stage separator

to compare simulated results of the production facility with the field analysis at current operating conditions. Figure 6 shows the comparison between simulated and the field analysis of both the gas (from the production separator) and the oil (after the FWKO). A very close match was obtained verifying the combined well stream model.

Optimization of Separator Pressure. The optimization was carried out for the mixed stream coming from the seven active wells using the EOS PVT simulator. Results are shown in Table 2. The optimization was carried out for average summer and winter temperatures (20 °C and 40 °C) and by groups; group I oil by lumping the well streams of W1, W2, and group II oil by lumping the streams W-3, W-4, W-6, and W-9. The objective of optimizing for each stream (group) is to test for limits of optimum separator conditions, since well workovers sometimes necessitates a changing production profile from different wells in the field. Results in Table 2 show that the average percentage of well-mixture oil improvement varied between 2% to over 3%. This result was confirmed by field operations showing 200-300 bbl/day condensates recovery from the condensate flash drum in the gas plant, which matches with the above percentage. In addition, the optimization of group II resulted in a more improved yield than group I. This result is attributed to the difference in volatility between the two types of oil.

Preliminary Optimization of Surface Facilities. Table 3 shows a preliminary comparison of the current and optimized facilities. The table shows, in addition to increasing the oil yield, a reduction in circulation rate and makeup rate for glycol in the dehydration unit. There is also a reduction in the power requirements for both the compressors and the inter-stage coolers in the compressor unit. In addition, another reduction is forecasted in the duty of the air cooler in the Propane refrigeration unit. In fact, there may not be a need for the condensate recovery in the refrigeration unit once the facilities are optimized.

Conclusions

Based on the above discussion, the following conclusions can be stated:

1. Better understanding of PVT properties is

essential for optimizing surface facilities. EOS modeling provided a means of modeling fluid properties of oils produced by the facility.

2. Optimization of separation operations resulted in 2-3% increased oil yield.

3. Optimization of separation operation was the key to significantly optimizing the power and glycol requirements within the plant.

We believe that our calculation with previously measured data and information yet to come will further advance the field development

Nomenclature

API	oil gravity, API
B_o	oil formation volume factor, bbl/STB
B_{ob}	oil formation volume factor at the bubble point, bbl/STB
P	pressure, psig
P_b	bubble point pressure, psig
P_{wf}	bottom hole pressure, psig
R_s	solution gas-oil ratio, SCF/STB
BHT	bottom hole temperature, °F
x, y	mole fractions in liquid and gas phases

Subscripts

b	bubble point
g	gas
o	oil

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Table 1. Comparison of fluid properties produced from different wells

	W -1	W -2	W -3	W -4	W - 6	W - 9
PRODUCTION TEST RESULT						
TEST SEPARATOR TEMP. (F)	88	90	93	74	132	80
TEST SEPARATOR PRESSURE (PSIG)	125	120	65	145	120	180
PRODUCING GOR-RANGE SCF / STB	520 - 775	199 - 478	659 - 1477	2115 - 2253	1002 - 1267	1316 - 2275
RESERVOIR LAB. DATA						
P _b , Psia	1933	1590	3852	4267	3748	3955
P _{wf} , Psia	3830	4195	3945	4375	4385	3960
SOLUTION GOR, SCF / STB	521	454	983	1365	1131	1467

Table 2a.Improvement in oil yield by optimizing Group I oil 1st stage separator pressure.

Group (1)	No. of Stages = 2				No. of Stages = 3			
	winter		Summer		Winter		summer	
Separator pressure, psia	75 (current)	120 (P _{opt})	75 (current)	120 (P _{opt})	75 (current)	200 (P _{opt})	75 (current)	200 (P _{opt})
Oil Formation Volume Factor (Bo)	1.369	1.366	1.404	1.400	1.362	1.351	1.396	1.383
Gas Oil Ratio Rs (SCF/STB)	558	554	596	591	548	532	586	567
Specific gravity	0.779	0.779	0.783	0.783	0.778	0.777	0.782	0.781
% Improv. (in Bo)	0.201		0.261		0.823		0.955	

Table 2b.Improvement in oil yield by optimizing Group II oil 1st stage separator pressure.

Group (2)	No. of Stages = 2				No. of Stages = 3			
	winter		Summer		Winter		summer	
Separator pressure, psia	75 (current)	200 (P _{opt})	75 (current)	200 (P _{opt})	75 (current)	410 (P _{opt})	75 (current)	410 (P _{opt})
Oil Formation Volume Factor (Bo)	1.817	1.789	1.877	1.844	1.812	1.756	1.871	1.809
Gas Oil Ratio Rs (SCF/STB)	1,535	1,489	1,595	1,545	1,527	1,437	1,588	1,491
Specific gravity	0.782	0.780	0.786	0.784	0.782	0.777	0.786	0.782
% Improv. (in Bo)	1.586		1.746		3.155		3.416	

Table 2c.Improvement in oil yield by optimizing field mixture 1st stage separator pressure.

Field-mixture	No. of Stages = 2				No. of Stages = 3			
	winter		Summer		Winter		Summer	
Separator pressure, psia	75 (current)	180 (P _{opt})	75 (current)	180 (P _{opt})	75 (current)	360 (P _{opt})	75 (current)	360 (P _{opt})
Oil Formation Volume Factor (Bo)	1.726	1.707	1.779	1.756	1.720	1.679	1.773	1.726
Gas Oil Ratio Rs (SCF/STB)	1,220	1,190	1,272	1,239	1,212	1,148	1,264	1,194
Specific gravity	0.781	0.780	0.786	0.784	0.781	0.777	0.785	0.781
% Improv. (in Bo)	1.156		1.308		2.485		2.739	

Table 3. Preliminary Optimization of Early Production Facility

<i>Specification</i>	<i>2-Stage Current Facilities</i>	<i>3-Stage Future Development</i>
1) Oil System	5150 BOPD • $H_2S = 30 \text{ ppm}$ • $BS\&W = 0.001\%$	5321 BOPD $H_2S = 50 \text{ ppm}$ $BS\&W = 0.0005\%$
2) Gas System • Sales Gas Flow (MMSCFD) • Water Content in the sales gas (lb/MMSCF) • Flared Gas (MMSCFD)	5.57 7 0.57	5.33 7 0.88
3) Condensate Recovery Condensate Recovered from Flash Drum <u>Condensate Physical Properties</u> Sp. Gravity API Viscosity (CP)	242 BPD 0.61 29 0.22	13.4 BPD 0.56 55 0.15
4) Glycol Unit • TEG Circulation Rate (GPh) • TEG Make-up (GPh) • TEG Purity (wt. %) • Reboiler Temp., ($^{\circ}F$) • Fuel Gas Consumption (MMSCFD)	14.34 0.184 99.8% 380 $^{\circ}F$ 0.006	12.24 0.14 99.8% 380 $^{\circ}F$ 0.0045
5) Power, hp • Gas Compressor • Propane Compressor • Interstage Air Cooler • Propane Air Cooler • TEG Reboiler Duty	<u>1st + 2nd Stage</u> 788 + 568 1.602 653 + 703 5.02 6.303	311 1.602 239 5.02 5.33
Total Power Consumption	2725hp.	562 hp.

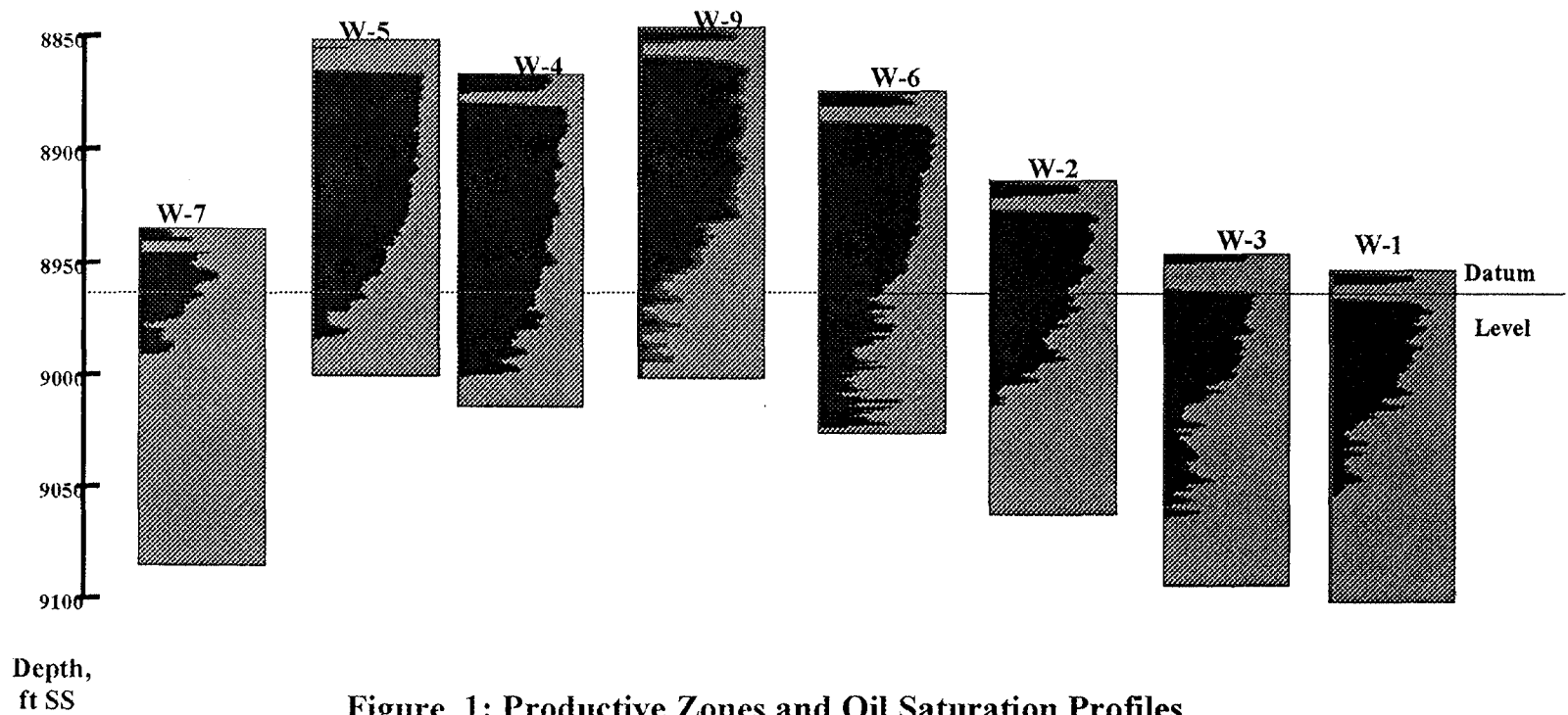
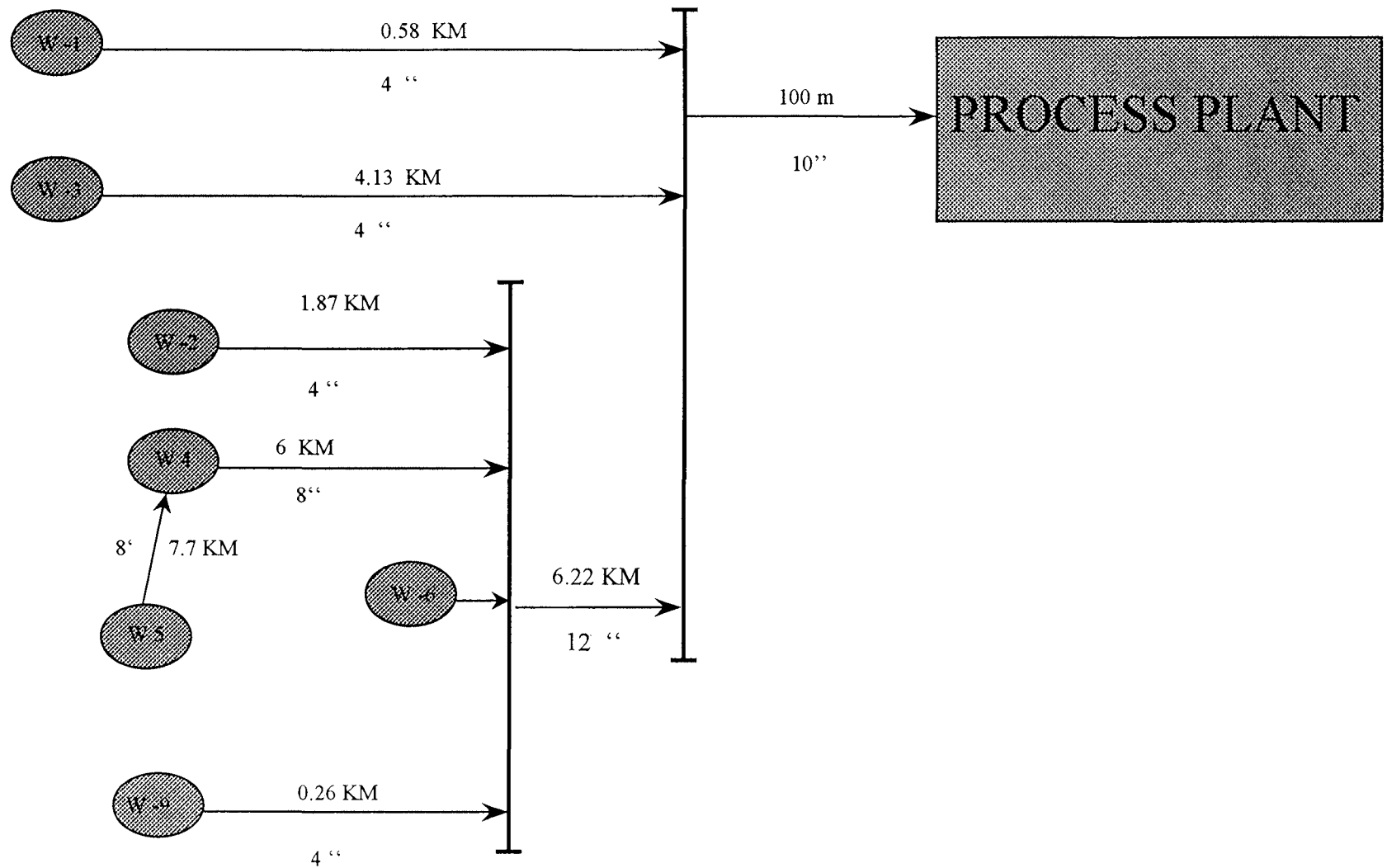


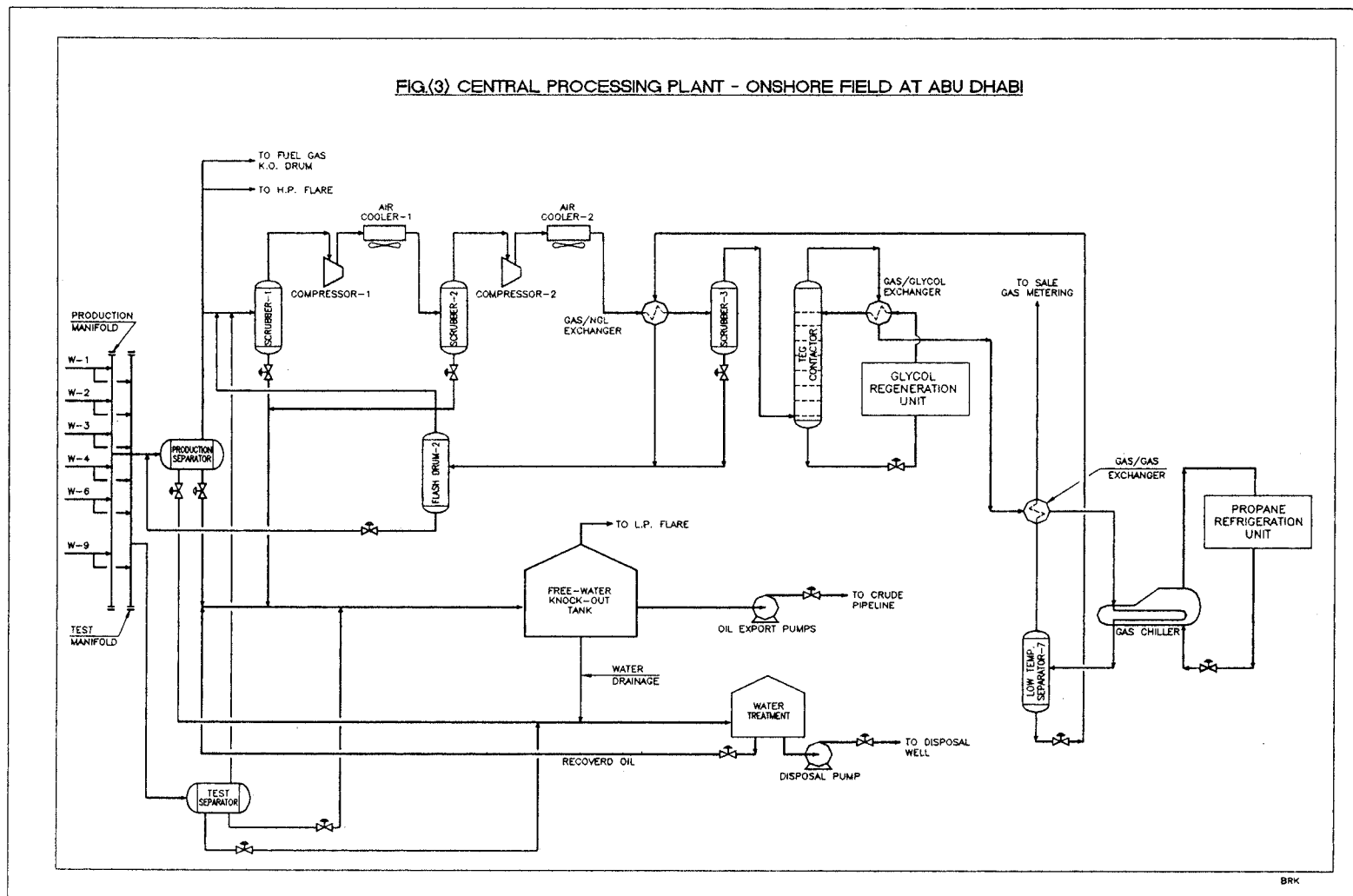
Figure 1: Productive Zones and Oil Saturation Profiles

Fig. (2) FLOWLINE NETWORK



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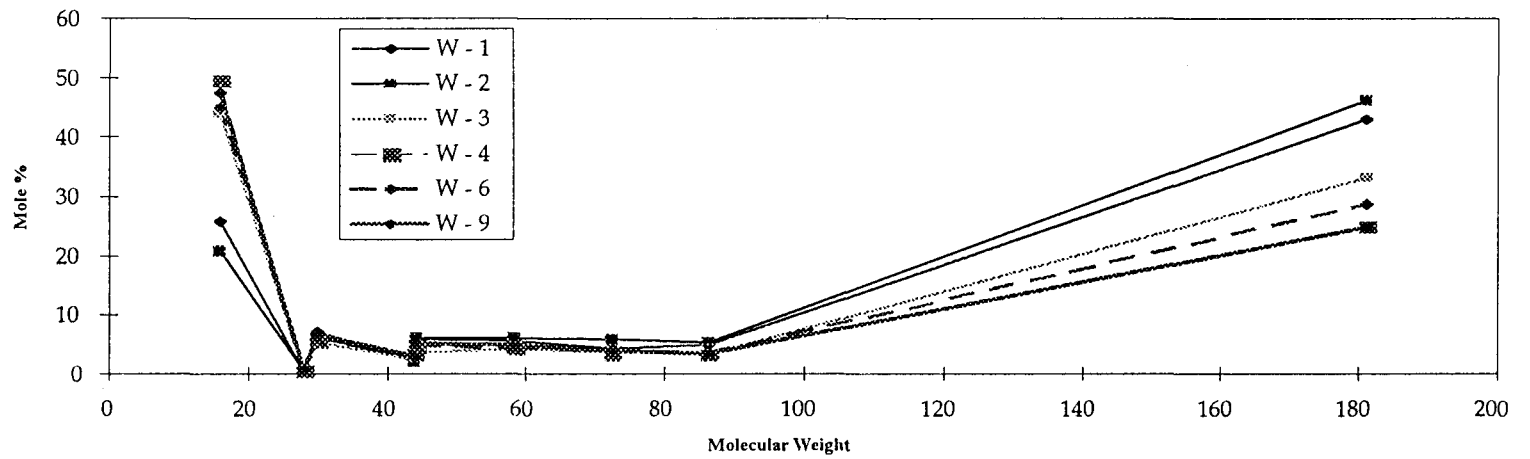
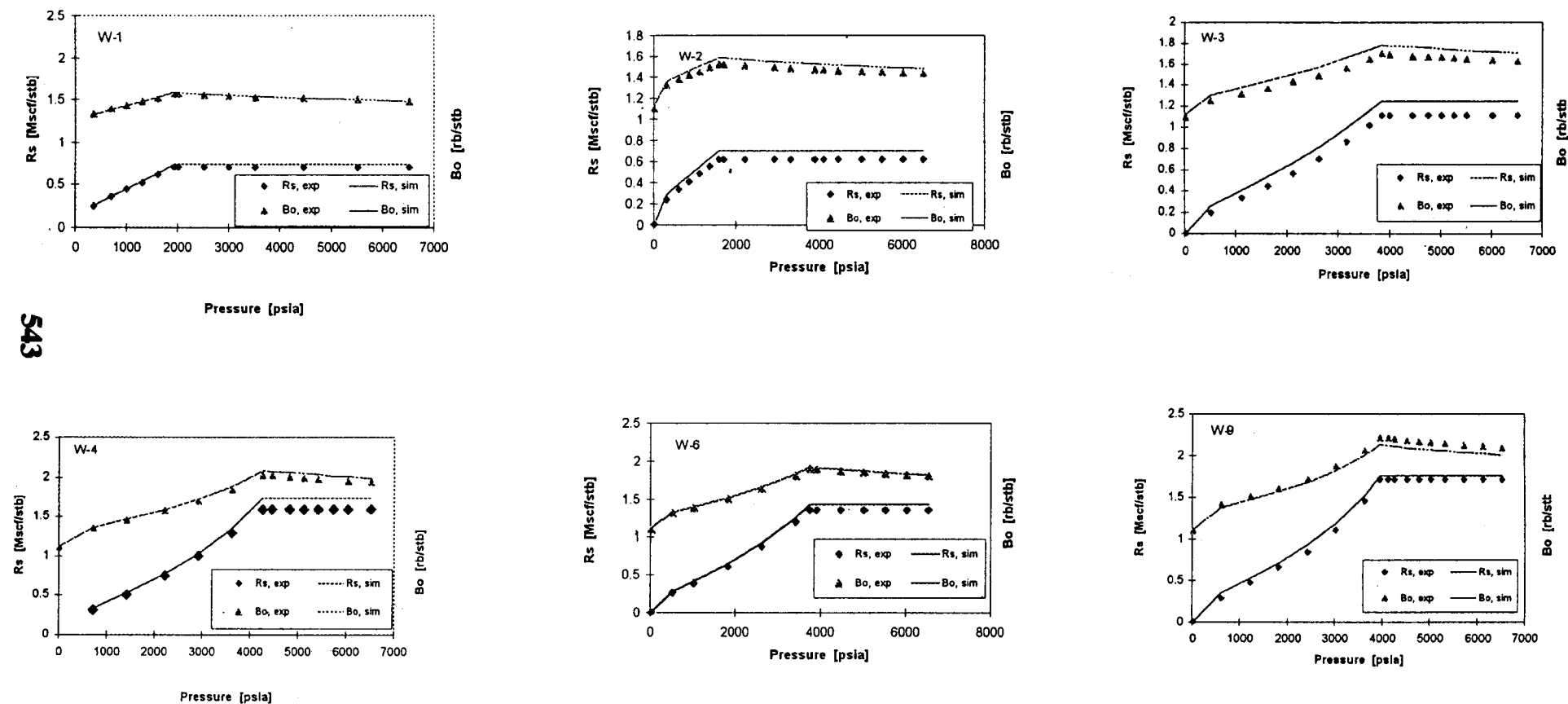


Fig. 4: Finger Print Plot for all Wells

Fig. 5: Comparison between Simulated and Measured R_s and B_o from all Wells

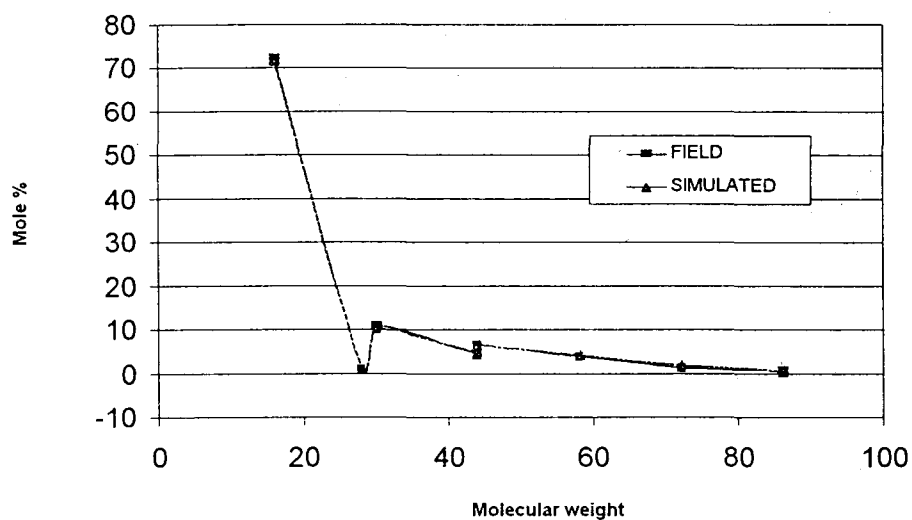


Fig. 6a: Comparison of Simulated and Measured Gas Field Analysis

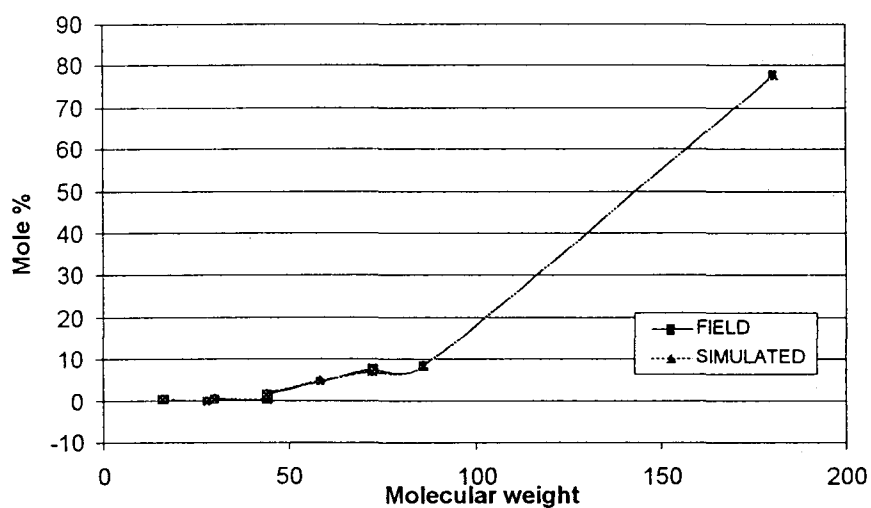


Fig. 6b: Comparison of Simulated and Measured Oil Field Analysis