A CASE STUDY TO DEMONSTRATE THE USE OF SCAL DATA IN FIELD DEVELOPMENT PLANNING OF A MIDDLE EAST CARBONATE RESERVOIR

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ABSTRACT
The objective of this paper is to demonstrate the impact of core analyses on the reservoir simulation model of a Middle East carbonate. An integrated SCAL study has been performed on reservoir cores from a carbonate reservoir. A comprehensive suite of laboratory measurements have been undertaken building on experience from previous studies, incorporating rigorous reservoir condition tests where appropriate.

The laboratory methods used are described and major results presented. To better understand the variability of the data, the results have been explored by means of principal components and marker analysis, using a multivariate exploratory analysis tool called Sirius. Principal Component Analysis (PCA) is a multivariate technique that finds orthogonal linear combinations in a data matrix, with the additional purpose of minimizing the residual variance in a least-square sense. The results from this exercise have given valuable information about the uncertainty involved and detected hidden information within the experimental data matrix.

The data derived from this study were used to enhance and validate the static and dynamic models developed. Static measurements were used to assess the uncertainty in the core and log measurements, and thus improve the confidence in the static model. Dynamic measurements were applied to validate the relative permeability used and the expected predictions in recoveries from water injection. This has resulted in an overall improvement in the continuous development of the reservoir field development model and predictions with reduced uncertainties.

LABORATORY METHODS
Imbibition and secondary drainage water-oil relative permeability measurements were performed using the steady state technique with live crude and simulated formation brine at full reservoir conditions using in situ saturation monitoring (ISSM). Complimentary centrifuge (single speed) oil relative permeability at elevated temperature, drainage and imbibition capillary pressures using porous plate at reservoir temperature and reservoir overburden pressures were also acquired.

Previous to the SCAL study a routine core analysis (RCA) program had been performed on a large number of core plugs. Based on the RCA measurements, the core plugs were grouped into two reservoir rock types (RRT) and a number of lithofacies. All SCAL plugs were X-ray CT scanned prior to final selection to minimize local heterogeneity, fractures and non-representative bedding planes. For the water-oil steady state tests 11 plugs were selected covering a number of lithofacies and two RRT's.

Preparation of Reservoir Core Plugs

Plugs were prepared by the restoration technique. Fresh state plugs were first cleaned by miscible solvent flooding using toluene, then toluene/methanol (1/1) mixture at 70°C followed by methanol. From the cleaning pre-study it was found that all samples were not effectively cleaned by this method, as measured by Amott wettability tests, and so all plugs also went through a second cleaning cycle. The second regime was a flush with a methanol/acetone/chloroform mixture (23/30/47 ratio by volume) at 70°C followed by methanol. Samples were then brine saturated and water permeability, k_w, measured. Core plugs were drained to S_{wi} by use of porous plate. This was done at 60°C using crude oil as draining fluid. Fluid distribution in the core plugs was checked by gamma scanning before and after the porous plate drainage. The core plugs were then mounted in a reservoir conditions core holder and $k_{eo}(S_{wi})$ measured using crude oil as the oil phase.

At reservoir conditions, the core plugs were flooded with live oil, and effective oil permeability at S_{wi}, $k_{eo}(S_{wi})$ was measured. The core plugs were aged at reservoir conditions for three weeks in live oil. $k_{eo}(S_{wi})$ was measured after ageing. This oil permeability was used as the reference permeability for the subsequent relative permeability calculations. In-situ saturation scans were taken at this stage to define S_{wi} at the start of the steady state floods.

Steady State Test Methods

Steady state water-oil relative permeability was performed by flooding oil and brine from the bottom of the vertically aligned core plug. Total flooding rate was set to either 6 or 20 mL/h (depending on the plug permeability) and the flooding started using a water fraction of 0.01. Gamma in-situ saturation and differential pressure were recorded continuously. At stable conditions, the water fraction was increased. This procedure was followed for water fractions, finishing with 100% water. At stable conditions, $k_{ew}(S_{or})$ was measured.
Secondary drainage steady state relative permeability was also performed from the bottom of the vertically oriented core plug finishing with 100% oil flooding.

Gamma calibration measurements were performed on core plugs fully saturated with live oil and with doped synthetic formation water at test conditions, see Spearing et al. (2004). Finally the plugs were oven dried prior to the measurement of pore volume and Klinkenberg corrected gas permeability at reservoir overburden pressure.

Data Interpretation

Relative permeability was calculated using Darcy's Law directly at each fractional flooding rate. The corresponding steady state saturations were calculated from the gamma in-situ saturation measurements. The SS pressure data and in-situ saturation profiles were history matched using the "Sendra" core flood simulator. Imbibition and drainage capillary pressures measured on samples from the same lithofacies were used in the core flood simulations where appropriate, in order to correct for capillary pressure end effects.

Capillary Pressure Measurements

Capillary pressure (P_c) was measured by centrifuge (multi-speed) at 70°C without any overburden pressure, and porous plate at reservoir temperature and reservoir overburden pressure using dead crude oil. Centrifuge tests were imbibition and secondary drainage, whilst porous plate tests were primary drainage, imbibition and secondary drainage. Samples were aged in dead oil at Swi at reservoir temperature prior to the centrifuge $P_{c.}$

Centrifuge Relative Permeability

After SS testing, the plugs were re-saturated with synthetic formation water and centrifuged to representative S_{wi}. They were then aged in dead crude at reservoir temperature and 5 bar pore pressure. Imbibition water-oil relative permeability was performed by use of an automated centrifuge at non-overburden conditions. Production of oil as a function of time was recorded by the automatic system. At stable conditions, the centrifuge was stopped, and effective water permeability, $k_{ew}(S_{or})$ was measured. The water saturation of core plugs was checked by Dean Stark extraction.

RESULTS

Plug characterization and relative permeability data measured during the steady state tests are shown in Table 1 along with identified lithofacies and RRT. The absolute brine permeabilities ranged from less than 1mD up to about 10mD, with porosities in the range of 16% - 23%. Remaining oil saturations ranged from around 20% PV down to very low values of 2% PV in one instance. These saturations were measured by ISSM alone. The four samples with low remaining oil saturations (ID 3, 4, 7 and 9) were anomalous as such low values are not normally expected. There was no correlation of residual saturations with RRT or lithofacies as observed earlier by Lombard et al. (2004). Remaining oil saturations were also measured in the single-speed centrifuge tests. These results are shown in Table 2. The four anomalous SS plugs show remaining oil saturations of around 20% PV from centrifuge measurements. It is inherent in the centrifuge to have in-homogeneous saturation profile which may end up in higher average saturation compared with the actual remaining oil. This effect is more significant for low centrifuge speed or in low permeability core samples as observed by Hirasaki et al. (1990) and Masalmeh (2002). The centrifuge speed used in this experiment was probably low for the kind of porosity and permeability of these samples which may explain the discrepancy in the remaining oil saturations in tables 1 and 2.

Another interesting result from the SS measurements was the saturation distributions measured at each fractional flow. Nine out of the eleven plugs tested showed fairly uniform in-situ saturation profiles with little indication of capillary end effects. The lack of end effect was especially apparent on the imbibition floods but less so on the drainages. A typical set of imbibition and secondary drainage in situ saturation profiles are shown in figures 1. The lack of end effects may have contributed to low remaining oil saturations. Core flood simulation used zero capillary pressure functions for those samples which did not exhibit capillary end effects. Wettability indices were measured by USBM method on two samples, 11 and 12, as part of the centrifuge capillary pressure measurement. These gave USBM indices of -0.17 and -0.40 respectively, which would indicate weak to moderately oil wet pore surfaces. Wettability indices were also derived from the porous plate measurements. The modified USBM wettability index, the Hammervold-Longeron Index, was calculated by:

$$WI = \frac{B_1}{B_1 + A_2} - \frac{B_2}{B_2 + A_1}$$

Where:

A1: The area under secondary drainage curve
A2: The area under the forced imbibition curve
B1: The area under the spontaneous imbibition curve
B2: The area under the spontaneous re-drainage curve

These gave wettability indices ranging from -0.08 to +0.38 across 18 separate core plugs with an average value of 0.10. These data are systematically more intermediate wet than the centrifuge wettability indices. The SS saturation profiles tend to reinforce the porous plate wettability indices, with the centrifuge data providing an overly oil wet estimation of wettability.

Simulated water and oil SS relative permeability curves for all 11 plugs are shown in figure 2. Sample identifier, lithofacies and RRT respectively are shown in the legend of curve. For the imbibition curves, there appears to be no discernable trend or relationship with lithofacies or reservoir rock type. Figure 3 shows a typical full drainage and imbibition cycle (primary drainage, spontaneous imbibition, forced imbibition and secondary drainage) measured using the porous plate with dead crude and simulated formation brine under reservoir temperature and reservoir overburden pressure. For the imbibition K_{rw} curves, low K_{rw} seems to be associated with low absolute permeability, at least for saturations greater than Sw = 0.5. A similar observation can be made for the drainage K_{rw} curves although the relationship is not so apparent. No such relationship can be seen in the K_{ro} curves.

PRINCIPAL COMPONENT ANALYSIS

Principal Component Analysis (PCA), see Birks (1987) and Kvalheim (1988) has been used for exploring experimental variance, detect possible outliers and find the reason for this prior to implementing the data in the reservoir evaluation process. Kalam et al. (2006) has detailed recent application of PCA in analysing porous plate measurements.

The major findings from the PCA analysis can be summarised as follows.
97 % of the total variance in the experimental data has been captured by analysing PC1, PC2 and PC3. Experiment P1-P12 corresponds to experiments reported in Table 1-2 as ID1-ID12. Experiments P13 and P14 are two experiments undergone standard Amott WI tests. Experiment P15-P32 are eighteen static porous plate PcRI experiments performed at pseudo reservoir conditions, i.e. dead oil/brine drainage and imbibition cycle at reservoir overburden stress and temperature. Evaluation of the different PCA plots, presented in figures 4a-f, detects P1 and P4 to be outliers. Furthermore, P1 is taken out by an abnormal permeability, while P4 is taken out by the porosity-Sor (remaining oil saturation) relationship for this experiment. It is also noticed that a combination of porosity – Swi versus Sor bring the borderline objects P3, P7 and P11 away from the dimensionless variance pattern. Irreducible water is the equivalent reason for P21 to be a borderline object.

THE RESERVOIR MODEL DEVELOPMENT

Figure 5 illustrates the implementation of the SCAL measured Pc data to assess saturation validation from logs at wells, one at crest and another at the flank. The good agreement in the saturation depth plots between logs and core measured data is a reflection of quality data, and the confidence in our porous plate measurements. Figure 6 shows the comparison of Petrophysical parameters of old SCAL, based on an assumption of cementation exponent ‘m’ of 2 and a saturation exponent ‘n’ of 2, with new SCAL. The impact of new SCAL, where ‘m’ was measured to be 1.88 and ‘n’ to be 2.25 on one of the wells tested was however, found to be negligible. The underlying case is the confidence of the asset development team on the new properly measured SCAL data.

Figure 7 shows the impact of measured relative permeability on the dynamic model predictions. Initial use of new SCAL data has shown a measurable increase in the plateau production years and a big predicted increase in the cumulative oil production compared with the old SCAL based on analogue fields. Analogue relative permeability data, based on possible experimental uncertainties thus show comparatively pessimistic production scenario compared with a simulation run based on proper measured relative permeability data. The units have been omitted to ensure confidentiality of the presented data. Again, use of measured SCAL data with proper QA/QC, significantly enhances the value and confidence of simulation model predictions.

CONCLUSIONS AND RECOMMENDATIONS

Principal Component Analysis is a powerful tool in identifying anomalies and outliers in measured SCAL data, even when these measurements are undertaken with extensive care and assessed for QA/QC. Saturations in steady state relative permeability measurements need to be checked by multiple techniques, and ISSM alone is inadequate to quantify saturations accurately. Quality SCAL data when coupled with PCA enhances the confidence of using the interpreted measurements to validate log and other reservoir engineering measurements. Error analysis, such as PCA gives a coherent validation of SCAL data in both static and dynamic reservoir model developments.

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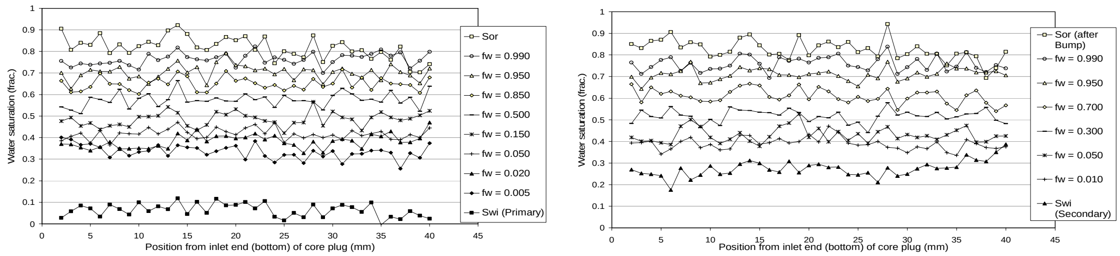


Figure1. Imbibition and secondary Drainage In-situ Saturation Profiles for Plug #6

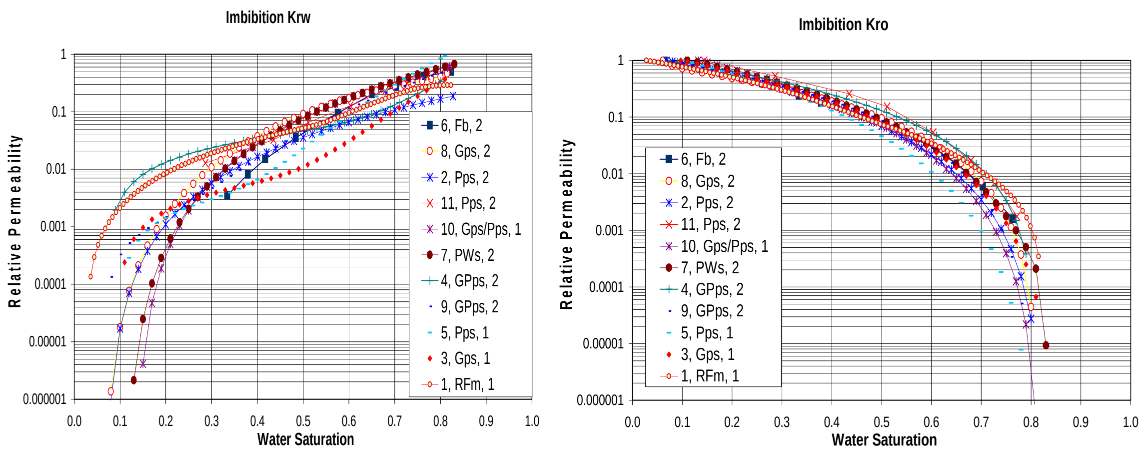


Figure 2. Simulated Imbibition Relative Permeability (Krw & Kro) Curves

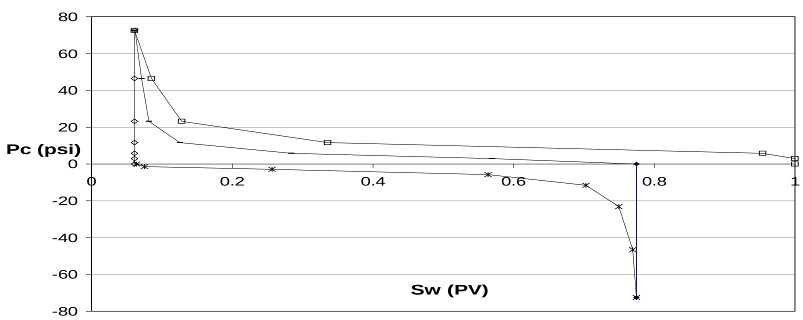


Figure 3. Porous Plate Measured Pc On A Representative Sample
Involving Drainage And Imbibition Cycles.

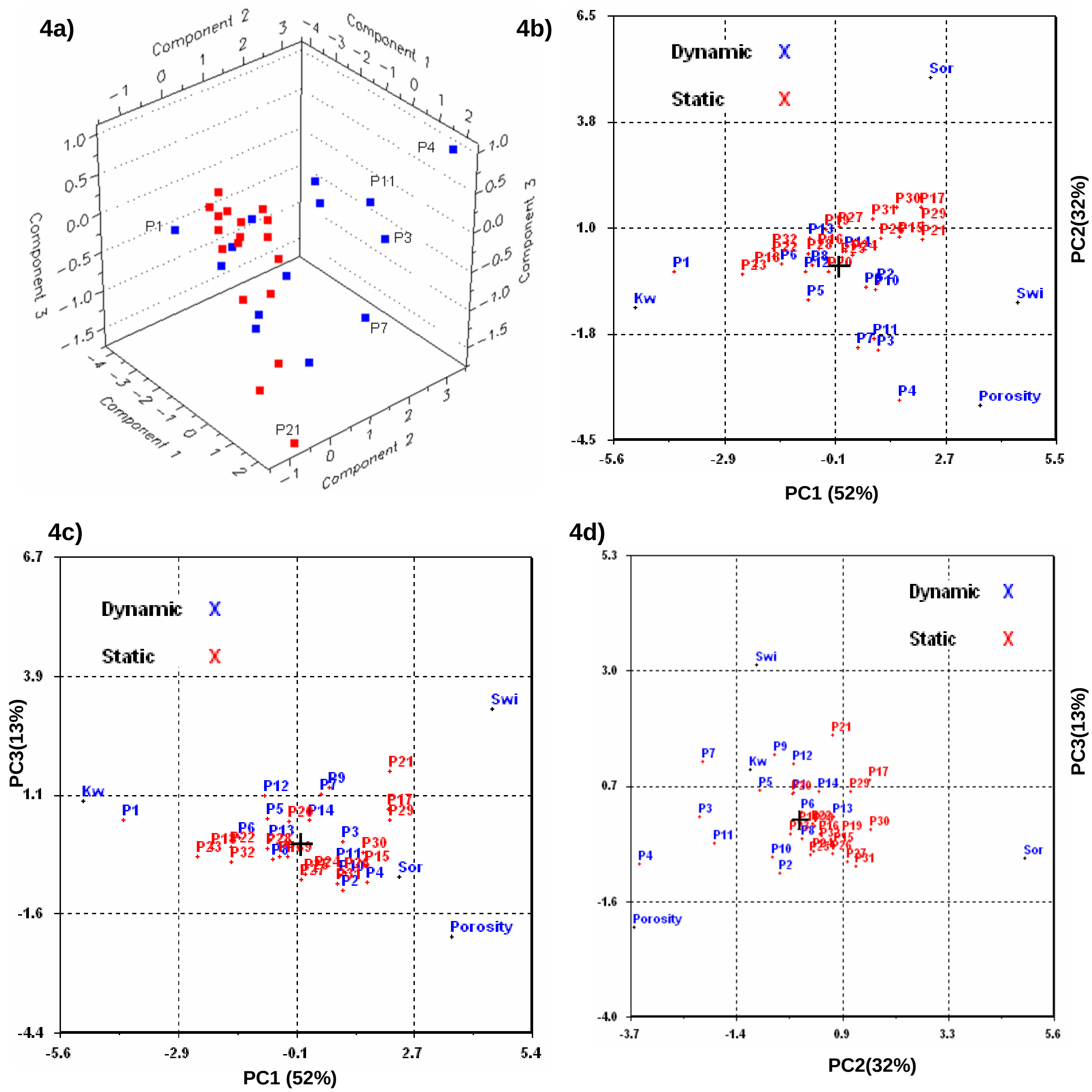
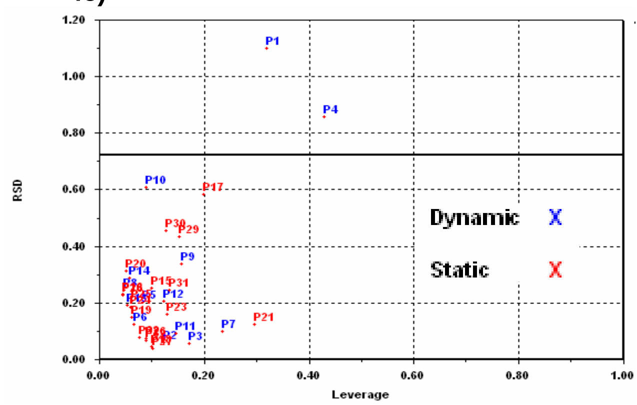


Figure 4 a) 3-D score plot; b) Biplot PC1 vs. PC2; c) Biplot PC1 vs. PC3; d) Biplot PC2 vs. PC3

4e)



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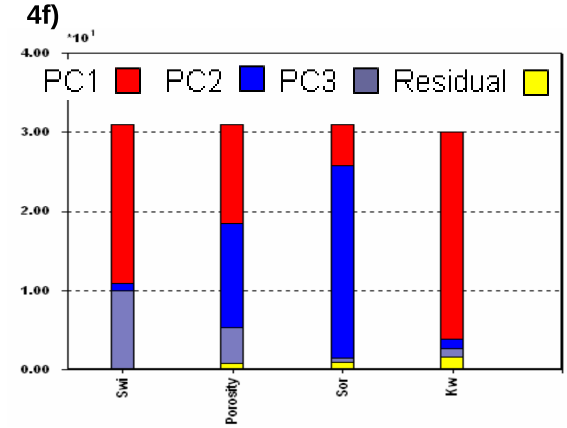

Figure 4 e) Leverage vs. Residual variance f) Influence of variable to total variance

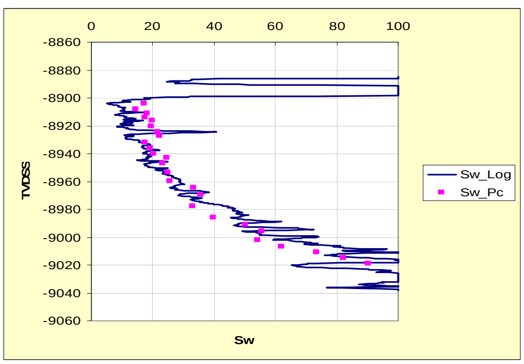

Figure 5a Crestal Well Initialization

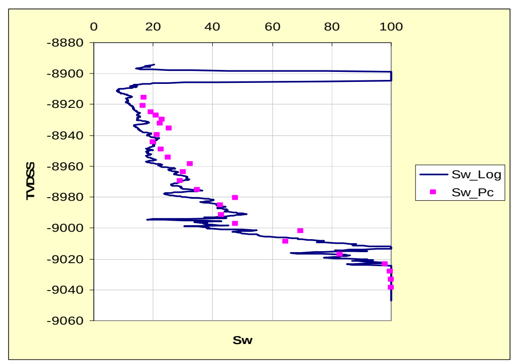

Figure 5b Flank Well Initialization

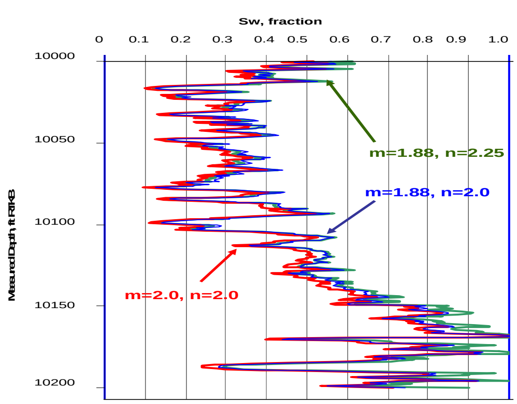

Figure 6 Comparison Of Old With New Petrophysical Parameters

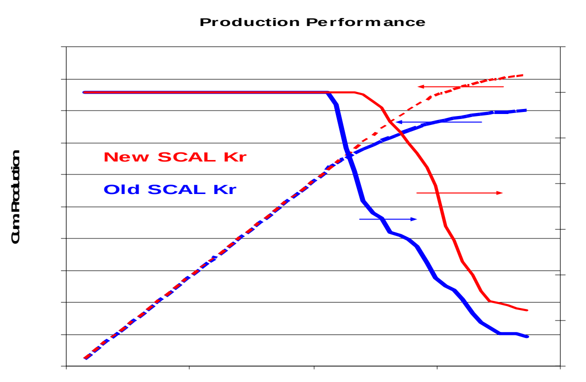

Figure 7 Reservoir Performance Based On Dynamic Simulation Model

Table 1: Plug Details and Measured Steady State Relative Permeability Data

ID		1	2	3	4	5	6	7	8	9	10	11
Depth	(ft)	10037.00	10039.50	100043.42	10045.67	10050.92	10053.67	10059.5	10062.5	10084.08	10105.25	10071.83
Lithofacies		RFm	Pps	Gps	GPps	Pps	Fb	PWs	GPs	GPps	Gps/Pps	Pps
Reservoir rock type		1	2	1	2	1	2	2	2	2	1	2
Length	(cm)	4.47	4.24	4.86	6.97	6.69	4.26	6.99	4.21	3.97	7.18	6.76
Diameter	(cm)	3.72	3.72	3.70	3.73	3.72	3.72	3.72	3.71	3.72	3.71	3.71
kw	(mD)	8.5	0.98	1.3	0.55	2.7	2.7	1.7	2.1	1.0	3.3	2.0
Swi, gamma	(frac.)	0.028	0.068	0.097	0.071	0.1 (1)	0.064	0.110	0.062	0.066	0.132	0.144
ko(Swi), live oil, res conditions. After ageing	(mD)	5.27	0.28	0.87	0.23	2.06	1.27	0.90	1.59	0.97	2.24	1.36
Steady state relperm Imbibition												
Total flooding rate	(cm^3/h)	20.0	6.0	20.0	6.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
S_{or}	(frac.)	0.181	0.181	0.085	0.022	0.148	0.182	0.069	0.194	0.083	0.214	0.179
$k_w(S_{or})$	(mD)	1.61	0.05	0.28	0.08	0.74	0.78	0.61	0.64	0.44	1.18	0.79
krw		0.306	0.179	0.322	0.348	0.360	0.614	0.678	0.402	0.454	0.527	0.581
Secondary drainage												
Total flooding rate	(cm^3/h)	20.0	6.0	20.0	6.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
S_{wr}	(frac.)	0.279	0.148	0.213	0.069	0.132	0.274	0.161	0.315	0.253	0.219	0.250
$k_o(S_{wi})$	(mD)	-	0.10	0.58	0.18	0.87	0.60	0.59	1.01	0.62	0.84	0.62
kro			0.357	0.667	0.783	0.422	0.472	0.656	0.634	0.639	0.375	0.454
Petrophysical measurements @ net overburden pressure												
Pore volume	(cm^3)	11.18	10.04	10.50	15.90	14.29	8.01	12.21	9.00	7.75	15.79	13.63
Porosity (caliper bulk volume)	(frac.)	0.230	0.218	0.201	0.209	0.197	0.173	0.161	0.198	0.180	0.203	0.187
Klinkenberg corrected gas permeability	(mD)	1.32	0.25	1.18	0.71	1.95	0.88	0.681)	1.53	1.1	2.67	1.75

(1) estimate

Table 2: Plug Details and Measured Centrifuge Relative Permeability Data

ID		1	2	3	4	5	6	7	8	9	10	11	12
Depth	**(ft)**	**10,037**	**10,040**	**10,043**	**10,046**	**10,051**	**10,054**	**10,060**	**10,063**	**10,084**	**10,105**	**10,072**	**10,075**
Lithofacies		**RFm**	**Pps**	**Gps**	**GPps**	**Pps**	**Fb**	**PWs**	**GPs**	**GPps**	**Gps/Pps**	**Pps**	**GPps**
Reservoir rock type		**1**	**2**	**1**	**2**	**1**	**2**	**2**	**2**	**2**	**1**	**2**	**1**
Length	(cm)	4.45	4.23	4.76	4.76	4.58	4.24	4.73	4.21	3.93	4.68	4.10	3.48
Diameter	(cm)	3.69	3.70	3.63	3.70	3.7	3.7	3.69	3.67	3.72	3.69	3.71	3.72
Petrophysical measurements													
Helium porosity	(frac.)	0.234	0.234	0.234	0.230	0.222	0.185	0.195	0.204	0.190	0.222	0.215	0.206
Water permeability, k_w	(mD)	7.12	0.95	1.34	0.74	2.35	1.91	1.57	2.48	6.32	3.93	4.09	3.33
Establishment of Swi													
Centrifuge speed	(RPM)	6800	6,800	6,800	6,800	6,800	6,800	6,800	6,800	6,800	6800	6,800	6,800
Capillary pressure	(bar)	5.2	5.0	5.4	5.4	5.3	5.0	5.4	5.0	4.8	5.38	4.9	4.3
Water produced	(cm^3)	9.0	8.9	10.4	10.7	9.6	7.35	8.2	8.3	7.6	9.8	8.5	6.7
S_{wi}	(frac.)	0.190	0.170	0.088	0.088	0.122	0.124	0.172	0.086	0.064	0.125	0.107	0.140
$k_o(S_{wi})$ after ageing	(mD)	5.1	0.31	1.10	0.50	2.48	1.71	0.76	2.04	2.35	2.70	2.30	1.83
Imbibition relative permeability by centrifuge													
Centrifuge speed	(RPM)	4900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4900	4,900	4,900
Oil produced	(cm^3)	7.1	7.1	7.4	8.15	8.45	4.8	5.95	6.2	6.0	6.90	7.05	5.55
S_w	(frac.)	0.829	0.834	0.738	0.783	0.895	0.696	0.773	0.769	0.803	0.741	0.848	0.852
S_{or}	(frac.)	0.171	0.166	0.262	0.217	0.105	0.304	0.227	0.231	0.197	0.259	0.152	0.148
$k_w(S_{or})$	(mD)	2.59	0.13	0.32	0.29	1.05	0.51	0.30	0.91	1.22	1.24	1.35	1.08
krw		0.50	0.43	0.29	0.59	0.42	0.30	0.39	0.45	0.52	0.46	0.59	0.59
Dean Stark extraction													
Water produced	(cm^3)	8.63	8.32	7.86	9.01	9.23	5.56	7.85	7.47	7.22	8.13	8.4	6.9
Water saturation	(frac.)	0.777	0.780	0.690	0.768	0.844	0.663	0.793	0.823	0.889	0.726	0.878	0.881
S_{or}		0.223	0.220	0.310	0.232	0.156	0.337	0.207	0.177	0.111	0.274	0.122	0.119