IRIS

International Research Institute of Stavanger

www.iris.no

Alexey Khrulenko

Reservoir complexity and recovery potential - Literature survey

Report IRIS - 2014/309

Project number:	7104114
Project title:	Task 7.4. Reservoir complexity and recovery factor potential
Client(s):	University of Stavanger
Research program:	The National IOR Centre of Norway
Distribution restriction:	Confidential

Stavanger, 26.11.2014

Geir Nævdal 28/11-14

Geir Nævdal
Project Manager
Sign.date

3/12-14

Dimitrios Hatzignatiou
Project Quality Assurance
Sign.date

Kristin M. Flornes 28/11-14

Kristin M. Flornes
Sr. Vice President
Sign.date

Contents

Summary

This report discusses screening techniques for evaluating the reservoir potential for IOR opportunities. The aim of screening techniques may be formulated as "to perform fast qualitative and/or rough quantitative evaluations of problems and opportunities for more detailed studies". It is necessary to mention that the accuracy of any method tends to increase along with its complexity and data requirements. Screening techniques do not require detailed information about the reservoir in question; however, they aim to give a quick direction (or road map) for more detailed reservoir simulation study.

A number of screening techniques were developed and published to date. This report aims to classify and describe the most typical and interesting approaches rather than to cover all existing publications.

The first section discusses the reservoir complexity index (RCI) which provides a measure to express reservoir features (including hard-to-formulate criteria) and properties from the standpoint of their influence on reservoir performance and ultimate recovery. This approach provides a convenient way to benchmark different reservoirs and identify IOR opportunities. Several publications dedicated to RCI were selected to demonstrate the theory and its practical applications.

The second section discusses miscellaneous approaches for IOR screening. A rough classification of the methods is given in the beginning. The classification is followed by description of five methodologies. These methodologies (which are believed to be most typical and interesting) are quite different, however they give a good understanding of how miscellaneous tools (expert, statistical and simulation) may be combined within a consistent workflow. The last subsection considers issues related to reservoir databases, which are important for the application of RCI and other statistical methods.

The last section, "Discussion", aims to formulate preliminary conclusions and ways-forward which are mostly related to the development of a methodology that accounts for particularities of Norwegian fields.

1 Reservoir complexity index and recovery potential

1.1 What is reservoir complexity?

In our opinion, the term "reservoir complexity" has to do with the following interrelated points:

1. Level of sophistication of production facilities; for instance, subsea production is more complex than production from platform.
2. Predictability of the reservoir behavior (to what extent may one rely upon a model to predict the reservoir behavior?); for instance, behavior of fractured reservoirs tends to be less predictable than non-fractured one.
3. Efforts required reaching the planned recovery.
4. Degree of uncertainty and risk associated with production planning.[HD1]
5. Amount of information required to represent essential features and fluid flow in a given reservoir. The more complex the reservoir, the more information is needed to characterize it. For instance, permeability of a perfectly homogeneous reservoir may be expressed via a single number, whereas permeability of a heterogeneous reservoir needs to be expressed via a distribution.
6. Performance sensitivity to reservoir description and upscaling errors;
7. Efforts are to be invested to extract oil from the reservoir in a profitable and time/cost efficient manner.

The last point aims to summarize the previous ones from operator's point of view. As it can be easily seen, complexity criteria can hardly be expressed[HD2] by numbers with a physical meaning. . However, it's obvious that some fields are more complex than others. Therefore "the complexity" needs a measure, by means of which it could be expressed. On the other hand, it is also evident that reservoir complexity has to do with a number of parameters of reservoir itself (quality, compartmentalization, heterogeneity, oil viscosity, oil column thickness etc.), its location (offshore/onshore) and economic environment. Reservoir Complexity Index (RCI), discussed in the next section, provides the methodology for it.

1.2 Published applications on reservoir complexity index

The scoring approach for screening of the reservoir complexity seems to originate from the work by *Dromgoole & Speers (1997)*.[HD3] However, some similar scoring methodologies may be found in earlier works; for instance, a similar methodology for IOR screening may be found in *Surguchev et al. (1992)*. Dromgoole and Speers attempted to develop a methodology for a reliable estimation of recoverable reserves that was capable to account for some hard-to-formulate criteria[HD4] such as reservoir quality, architecture and structural complexity.

The authors proposed to assess the effect of the whole geological reservoir complexity on field reserve estimates by dividing potential reservoir complexities into nine categories (Table 1). Each category is given a score in the scale from 1 to 5 based on the following rating system:

- Structural complexity:
  1. Very low degree of complexity
  2. Low degree of complexity
  3. Medium degree of complexity
  4. High degree of complexity
  5. Very high degree of complexity

- Reservoir quality and architecture:
  1. Enhances recovery
  2. May help recovery
  3. No effect on recovery
  4. Detrimental to recovery
  5. Very detrimental recovery

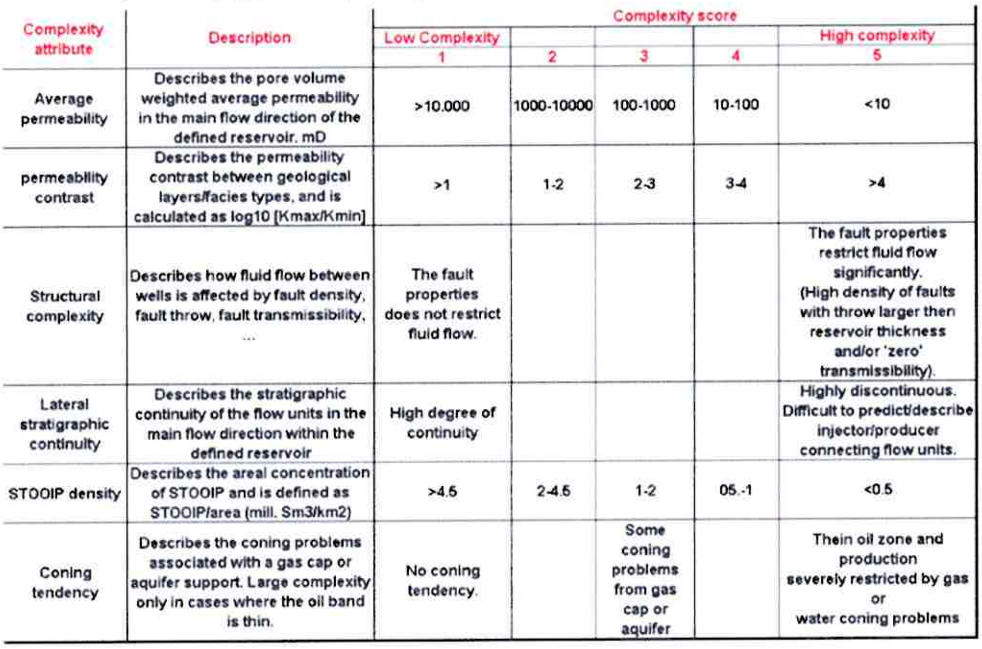
All scores are finally added to calculate the overall reservoir complexity.

Table 1.

Structural complexity	Reservoir quality and architecture
Overburden complexity Fault complexity	Reservoir layering Reservoir continuity Permeability channels Barrier continuity Fault transmissibility Fractures Diagenesis

Norwegian Petroleum Directorate (NPD) proposed the use of Reservoir Complexity Index (RCI) to express the complexity of the reservoir and indicate how challenging it may be to achieve a higher recovery factor[HD5]. A number of parameters was selected to describe the reservoir conditions, summarized in the table below:

Table 2. Scoring scale used by NPD (*Bygdevoll (2010)*)



Complexity attribute	Description	Complexity score				
		Low Complexity				High complexity
		1	2	3	4	5
Average permeability	Describes the pore volume weighted average permeability in the main flow direction of the defined reservoir. mD	>10.000	1000-10000	100-1000	10-100	<10
permeability contrast	Describes the permeability contrast between geological layers/facies types, and is calculated as log10 [Kmax/Kmin]	>1	1-2	2-3	3-4	>4
Structural complexity	Describes how fluid flow between wells is affected by fault density, fault throw, fault transmissibility, ...	The fault properties does not restrict fluid flow.				The fault properties restrict fluid flow significantly. (High density of faults with throw larger then reservoir thickness and/or 'zero' transmissibility).
Lateral stratigraphic continuity	Describes the stratigraphic continuity of the flow units in the main flow direction within the defined reservoir	High degree of continuity				Highly discontinuous. Difficult to predict/describe injector/producer connecting flow units.
STOOIP density	Describes the areal concentration of STOOIP and is defined as STOOIP/area (mill. Sm3/km2)	>4.5	2-4.5	1-2	05.-1	<0.5
Coning tendency	Describes the coning problems associated with a gas cap or aquifer support. Large complexity only in cases where the oil band is thin.	No coning tendency.		Some coning problems from gas cap or aquifer		Thein oil zone and production severely restricted by gas or water coning problems

The complexity scores for selected Norwegian fields were calculated according to this table and plotted on x-axis, whereas the corresponding recovery factors were included on the y-axis in Figure 1. As it can be seen, the points demonstrate satisfactory linear trend between recovery factor and RCI.

Bygdevoll (2010) also analyzed the influence of field size and production facility type to recovery factor which seems to be tangible (Figure 2). [HD6]

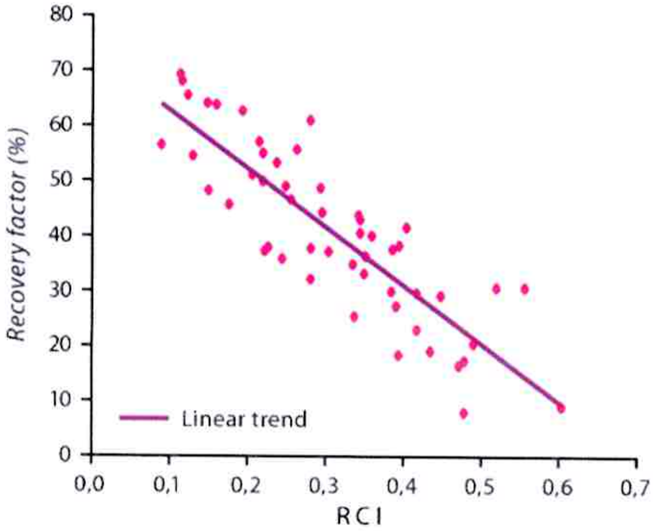


Figure 1. RCI vs. Oil recovery for NCS fields (Bygdevoll (2010))

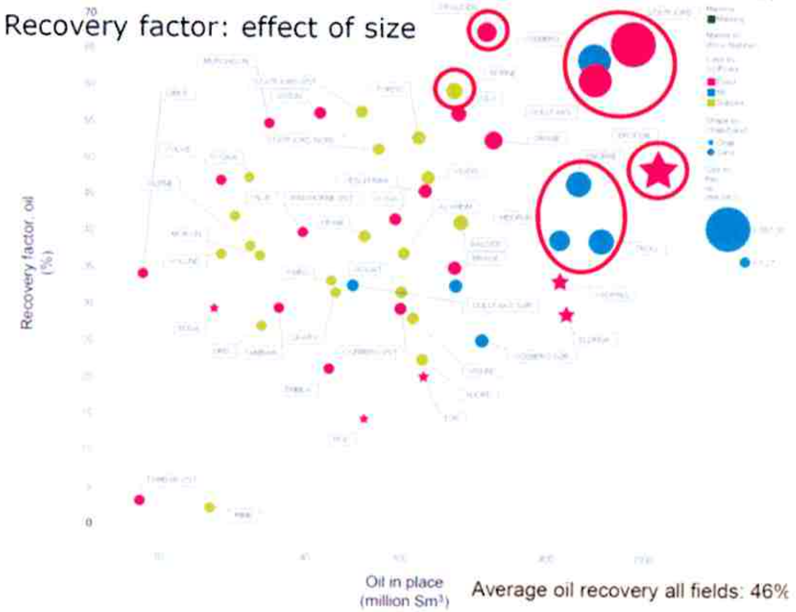


Figure 2. RF vs. OOIP (Bygdevoll (2010))

Wickens & Kelly *(2010)* used a similar approach that relates recovery factor with a complexity index determined via the following four parameters which were considered as the most essential:

- Oil viscosity;
- Vertical reservoir heterogeneity;
- STOIIP areal density;
- Structural compartmentalization/faulting.

Each parameter was defined via the scoring scales outlined in Table 3:

Table 3. RCI scoring scales used by *Wickens & Kelly (2010)*

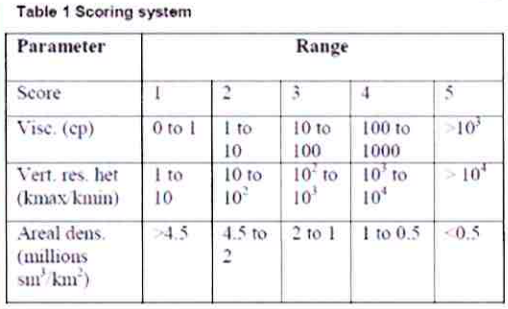


Table 1 Scoring system

Parameter	**Range**				
Score	1	2	3	4	5
Visc. (cp)	0 to 1	1 to 10	10 to 100	100 to 1000	>10^3
Vert. res. het (kmax/kmin)	1 to 10	10 to 10^2	10^2 to 10^3	10^3 to 10^4	> 10^4
Areal dens. (millions sm^3/km^2)	>4.5	4.5 to 2	2 to 1	1 to 0.5	<0.5

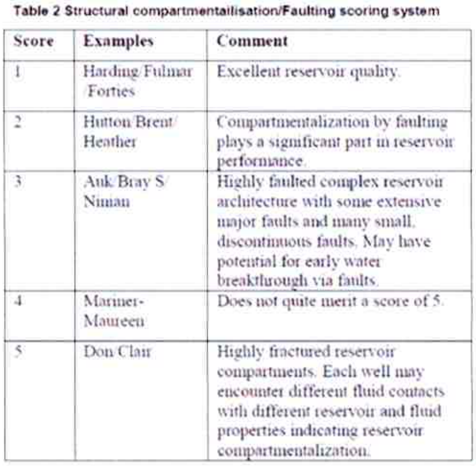


Table 2 Structural compartmentalisation/Faulting scoring system

Score	**Examples**	**Comment**
1	Harding/Fulmar/Forties	Excellent reservoir quality.
2	Hutton/Brent/Heather	Compartmentalization by faulting plays a significant part in reservoir performance.
3	Auk/Bray S/Niman	Highly faulted complex reservoir architecture with some extensive major faults and many small, discontinuous faults. May have potential for early water breakthrough via faults.
4	Mariner-Maureen	Does not quite merit a score of 5.
5	Don/Clair	Highly fractured reservoir compartments. Each well may encounter different fluid contacts with different reservoir and fluid properties indicating reservoir compartmentalization.

[HD7]

After ranking each parameter, the weighted sum was considered as a complex parameter for reservoir complexity. The weights are to be determined by curve fitting to get the best match to data. Wickens & Kelly tested their methodology for UK fields and managed to get a good correlation (Figure 3) between the complexity index and recovery factor.

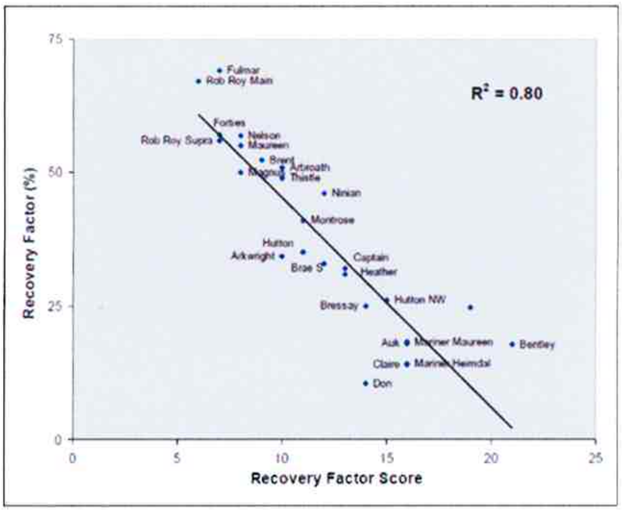


Figure 3. Recovery factor vs. complexity index (Wickens & Kelly (2010))

The authors also analyzed the influence of some scoring parameters (Figure 4); structural complexity and viscosity turned out to be most influential whereas the impact of the areal density was almost negligible.

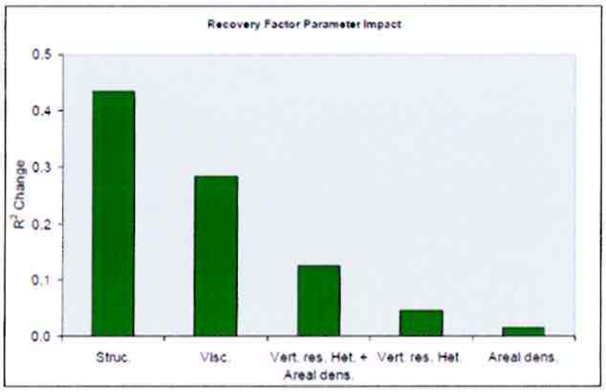


Figure 4. Sensitivity of the correlation to the complexity index components *(Wickens & Kelly (2010))*

In general, this correlation demonstrated a satisfactory prediction capability, clarity of the basic principles and required input data. The scoring approach is most interesting from the standpoint of dealing with miscellaneous hard-to-formulate parameters, which cannot be assessed directly or expressed via a parameter with a physical meaning, but can be intuitively understood and ranked by an expert.

Horikx et al. (2013) developed a methodology to assess target recovery factors of chalk oil fields accounting for the following features (Table 4):

Table 4. Reservoir features used in work by Horikx et al. (2013)

Lateral Reservoir Quality Faulting and micro-fracturing Lateral permeability variation	Dynamic Aspects Moveable oil fraction Wettability Compaction drive potential Gas cap and bubble point Oil mobility
Vertical Reservoir Quality Net-to-Gross ratio Vertical connectivity Vertical permeability profile	Geography and Economics Location of field Effective oil column

However, the methodology is not clear and is heavily based on "engineering judgments" whose meanings [HD8][AK9]were not provided. The interesting point is usage of reservoir simulation to capture oil mobility vs. recovery factor relationship (Figure 5).

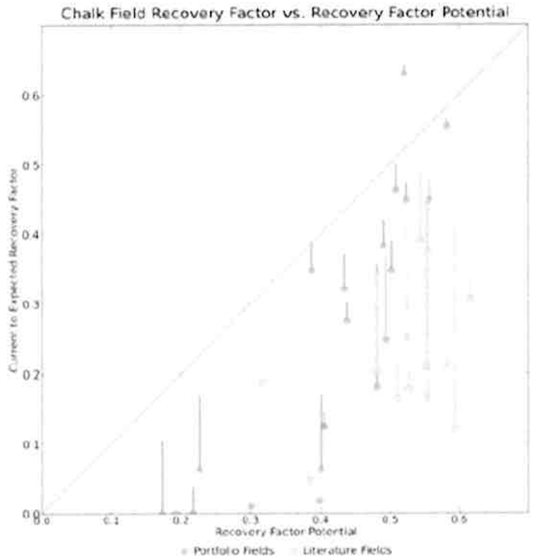


Figure 5. Cross-plot of current, expected and potential recovery factors by *Horikx et al. (2013)*

2 Screening procedures for IOR/EOR potential evaluation

2.1 General classification of screening methods

In general, all existing approaches for IOR potential screening may be divided roughly into the following three categories:

1) Expert methods based on EOR criteria:

   a) "Rules of thumb" techniques for which the most essential reservoir properties (oil viscosity, GOR, etc.) are to be compared with typical values established by practice of EOR field implementations. A number of criteria has been published and a comprehensive review may be found in *Lake et al. (2008)*. A newer example of such criteria may be found in paper by *Dickson et al. (2010)*.
   b) Scoring methods (e.g., *Surguchev et al. (1992)*).
2) Statistical methods use databases to derive required statistical estimates. The following techniques may be used to capture correlations of recovery factor vs. reservoir parameters:
   a) Cluster analysis (*Alvarado et al. (2002)* and *Babushkina et al. (2013)*);
   b) Neural networks (*Surguchev & Li (2000)* and *Ibatullin et al. (2002)*);
   c) Bayesian Belief Networks *(Zerat et al. (2011))*
3) Reservoir models:
   a) Analytical methods: decline curves, material balance and analytical solutions (Dykstra-Parsons, Buckley–Leverett) for EOR processes;
   b) Numerical methods: simplified and mechanistic reservoir models.

As it will be illustrated by examples in the next subsection, all these methods can coexist and complement each other within a single workflow and framework. For instance, proxy-models may be as reservoir models based on parameters derived by means of a statistical analysis of performance of real field. On the other hand, there are statistical proxy-models based on results of series of simulation runs.

2.2 Industrial workflows for IOR screening

2.2.1 IRIS

The SWORD application (*Surguchev et al., (2011)*) consists of three modules for IOR/EOR screening listed below:

- Applicability screening – EOR criteria;
- Recovery factor estimation – module based on Cluster Analysis (*Babushkina et al. (2013)*) for statistic estimation of recovery factors for given values of porosity, permeability, saturation, pressure, temperature, oil viscosity and type of formation rock.
- Performance prediction – analytical solutions based on Dykstra-Parsons and Buckley-Leverett for:
    - waterflooding;
    - polymer / surfactant flooding;
    - nitrogen / CO_2 / hydrocarbon miscible flooding;
    - cyclic waterflooding;
    - WAG injection;
    - steam flooding.

2.2.2 BP

Smalley et al. (2009) described the Reservoir Technical Limits (RTL$^{\text{TM}}$) approach that is developed by BP. This approach represents an oil recovery factor, RF, in the form of the product:

$$RF = Eps \times Ed \times Es \times Ec$$

where:

Eps – pore-scale displacement efficiency;

Ed – drainage efficiency that refers to connectedness to a producing well;

Es – sweep efficiency that refers to movement of oil to producers within the drained volume;

Ec – cut-offs efficiency that refers to loss of oil recovery related to end of field life/access due to the following reasons:

- Depletion of energy;
- Expiration of production facilities lifetime;
- End of license agreement.

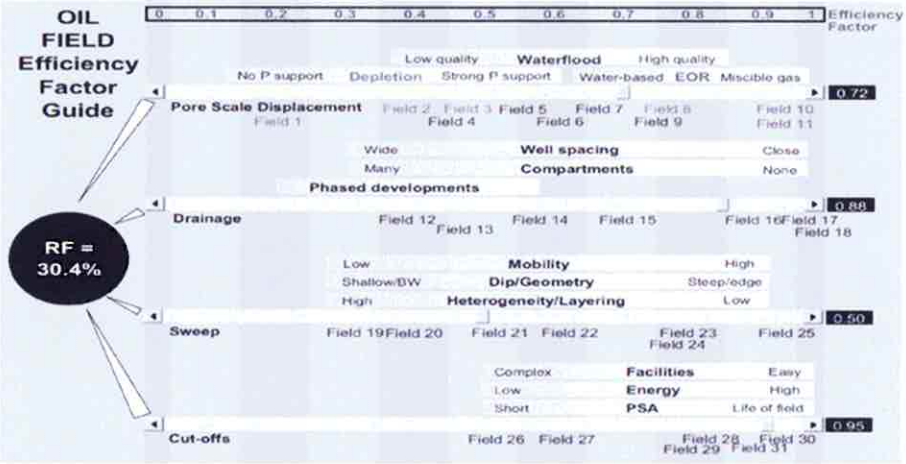


Figure 6. Screen shot of BP's RTL toolkit[HD10] (Smalley et al. (2009))

BP's methodology consists of the following steps:

I. Base definition – estimate current recovery potential;

II. Identification of opportunities to increase the following RF components:

Eps: waterflooding IOR/EOR;

Ed: infill drilling, recompletions, sidetracks and extended-reach wells, etc.;

Es: infill drilling, sidetracks, intelligent completions, water/gas shut off;

Ec: artificial lift, facilities upgrades, capture of nearby production etc.;

III. Opportunity description and prioritization related to:

   a. activity[HD11][AK12] involved;
   b. expected resource volume added by the activity;
   c. time scale;
   d. which efficiency factor is being improved;
   e. likely cost per incremental barrel;
   f. probability of success;
   g. key risks;

h. technical challenges/barriers;
i. possible technical solutions and action plan.[HD13][AK14]

These opportunities are divided into the following categories:

- Options – opportunities that are well defined, are economically sound, and can be implemented in the short-term (~1 year);
- Possibilities – medium- (1 – 5 years) and long-term (>5 years) opportunities that can be implemented economically using either existing technology or technology that requires only incremental development;
- Barrier opportunities – barriers exist for these opportunities to be implemented.

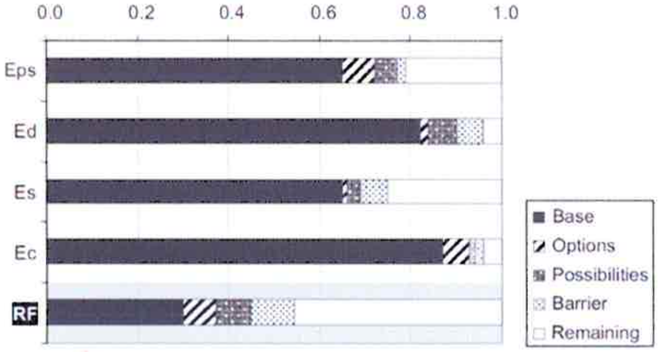


Figure 7. The illustration of different opportunities to increase the efficiency factors[HD15] *(Smalley et al. (2009))*

IV. Quality control:
   a. Internal consistency check;
   b. External consistency check – involves plotting the recovery factors for the options, possibilities and barrier opportunities against the complexity index [HD16](based on Dromgoole and Spears (1997), but using more sophisticated scoring and weighting methods) [AK17]for a range of analogue fields.

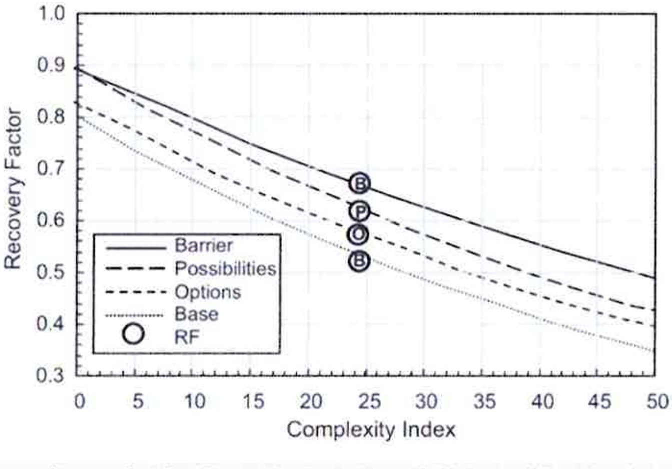


Figure 8. Recovery factors for the Base, Options, Possibilities and Barrier (circles) compared to analogue-calibrated trend lines for fields with similar E_{ps} and well spacing ***(Smalley et al. (2009))***. [HD18]

V. Data Capture and Follow-up.

2.2.3 ExxonMobil

Dickson et al. (2010) described the Improved Hydrocarbon Recovery (IHR) screening methodology used by ExxonMobil. This methodology is organized as follows:

I. Screening and prioritization

I.1. Collect reservoir and fluid data: *"Analog data used in the screening tool when specific reservoir data is not available. The basis for analog generation is the data provided by the C&C Reservoir and IHS commercial databases. For most properties, analog values are obtained from proven and probable (PP) weighted averages based on a user-defined region generation, basin, sub-basin, reservoir, zone, period, or epoch. Reservoir temperature and pressure are determined from temperature and pressure vs. depth curves for analog fields. Average permeability is estimated from the PP from weighted average in conjunction with minimum and maximum average permeability information (usually reported by IHS)"*[HD19] ***(Dickson et al. (2010))***

I.2. Pass/fail test by comparing the following properties with screening criteria of EOR methods:

a. Reservoir pressure;
b. Formation salinity;
c. Reservoir depth;
d. API gravity;
e. Oil saturation;
f. Reservoir temperature;
g. In-situ viscosity;
h. Payzone thickness;
i. Average permeability;
j. Reservoir dip.

The screening criteria and properties are plotted and compared against each other. A process passes the screening test when its horizontal bar (Figure 9) crosses the vertical black line denoting the viscosity of the reservoir in question. [HD20]

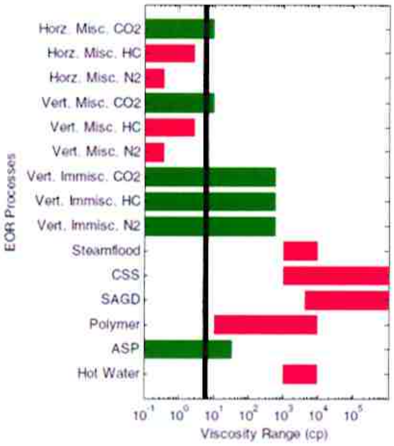


Figure 9. Illustration of the pass/fail test[HD21] (Dickson et al. (2010))

I.3. Assign[HD22][AK23] a score according to pass/fail test result.

I.4. Weight score according to property importance:

TABLE 1: IMPORTANT RESERVOIR PROPERTIES (× DENOTES SHOW-STOPPER CRITERIA; ↑ DENOTES INCREASED WEIGHTING)

EOR Process	K_h	S_o	μ	Depth	Pressure	Thick.	Salinity	Temp.
Gas Injection (miscible/immiscible)	↑	-	↑	-	↑/×	-	-	-
Chemical	↑	-	-	-	-	-	↑	↑/×
Thermal (steam-related)	-	↑	×	↑/×	×	↑	-	-
Hot water	-	↑	×	↑/×	-	↑	-	↑/×

I.5. Compare the final normalized scores for all EOR options and rank them as follows[1]:
  - Recommended, if the score > 0.8;
  - Marginally recommended, if the score is greater than 0.6 and less than 0.8;
  - Not recommended, if the score < 0.6.[HD24]

II. **Sector modeling and type curve generation.** Generic sector models are used to generate type curves for a given reservoir description and properties (depositional environment, vertical/horizontal continuity, permeability distribution, etc.).

III. **Flowstream generation.** The generated type curves may be used in a proxy simulator for other relevant fields.

2.2.4 Schlumberger

Graf et al. (2011) performed candidate screening for waterflooding implementation in over 100 Nigerian reservoirs for additional recovery potential and possible further evaluation. The developed workflow consisted of four steps:

1. Dataset survey to identify key parameters for the classification of reservoir types;
2. Back population of missing data. Self-organizing maps (SOM) models are used as a regression tool to compute missing values on the basis of available values of a certain measurement and on the basis of the identified correlations among the parameters.
3. Construction of stochastic proxy models (also known as surrogate reservoir models) to assess incremental oil recovery due to waterflooding. A simple 2D slanted cross-sectional numerical model was used.
4. The stochastic output of the proxy models is used as states for Belief Bayesian Network in order to calculate joint probabilities. On the basis of the resulting probabilities, all reservoirs are ranked for the potential of success of waterflooding implementation.

2.2.5 C&C reservoirs

C&C reservoirs is a US-based consultancy which gathers and provides knowledge base for the upstream industry (mentioned above in 2.2.3). *Lu et al. (2011)* proposed the following methodology:

1) **Selection of candidate analogs**. Identify field analogues according to the following attributes[2]:
   a) Onshore or offshore development. The production performance of offshore fields usually presents high annual recovery rates with a short field life (<30 years). By contrast, typical onshore fields generally have low annual recovery rates and longer field life (50-100 years);
   b) STOIIP or areal density of STOIIP. A field with large STOIIP will generally experience longer developing stage characterized by a low to moderate annual recovery rate. Small fields, on the contrary, usually display a production performance pattern similar to that of offshore fields;
   c) Depositional system/environment and sandbody/facies types. For instance, a carbonate reef reservoir will present a markedly different production performance and ultimate recovery factor than a fluvial sandstone reservoir;

---

[1] Cut-off values are based on comparison between prioritized and actual implemented EOR projects.

[2] The authors do not reveal any details, but they refer to *Wickens & Kelly (2010)*.

   d) Viscosity or mobility ratio;
   e) Permeability and reservoir heterogeneity;
   f) Natural drive mechanism and secondary recovery/EOR applications;
   g) Other relevant attributes: rock wettability, structural/stratigraphic compartments, fault attributes and reservoir depth.

2) **Candidate analogs ranking, statistic and calculations**. Selected analog reservoirs are used to derive production stage durations (Figure 10). Based on the ranking results from low to high recovery factor, all candidate analogs can be divided into three categories (low, medium and high case). Then statistical analyses and simulations are run for the three cases separately.

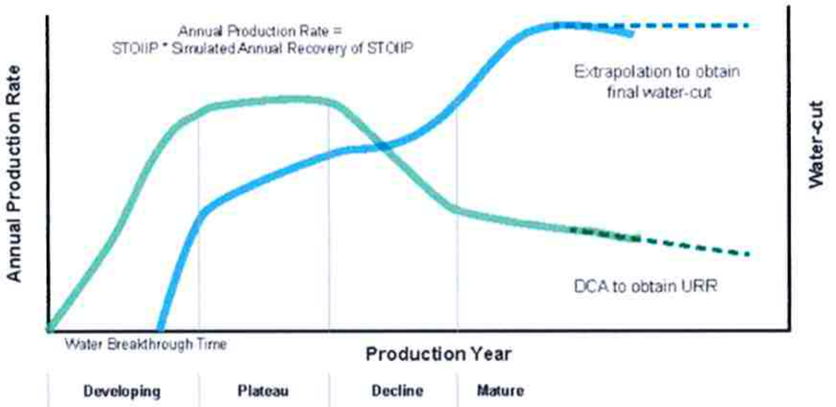


Figure 10. Schematic illustration of developing stages (Lu et al. ((2011)))

3) **Full field performance forecast**. Decline curve analysis, using STOIIP as the basic input.

2.3 Reservoir databases

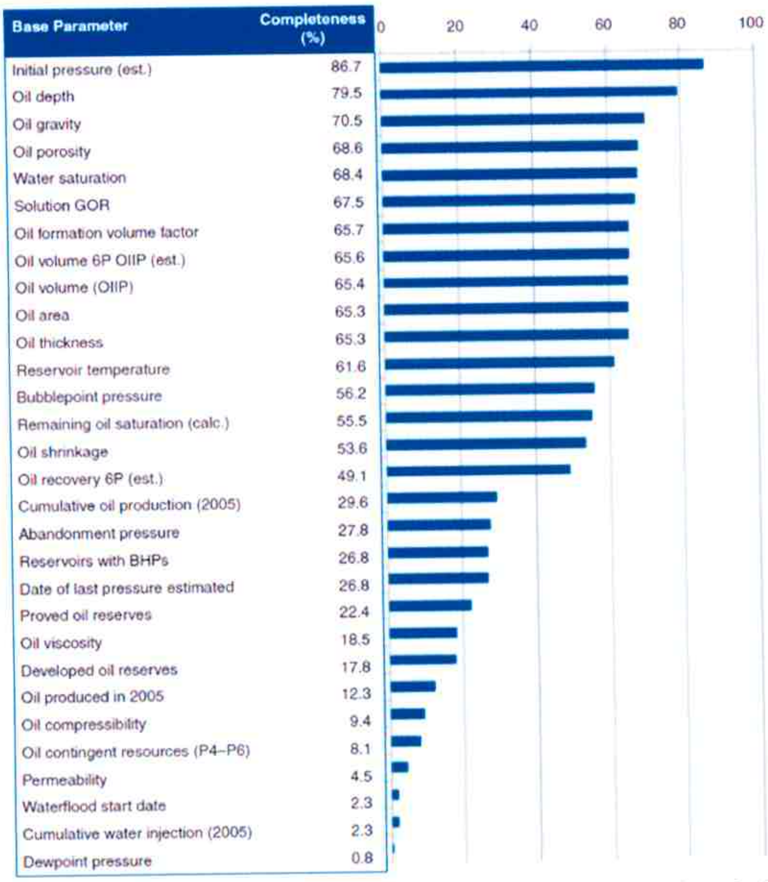
To date there is a number of industrial databases which, with different levels of detail and completeness, summarize reservoir properties and production data. Data inconsistency and incompleteness are the main drawbacks of these databases that prevent them from being used for practical purposes. For example, in the above-mentioned paper by Graf et al. (2011), the following statistics were reported for a database of 12 parameters for 100 reservoirs (Figure 11):

- Database overall completeness – 40%;
- Initial reservoir pressure – 87%;
- Oil viscosity – 18,5%;
- Permeability – 5%;
- Dataset consistency for all reservoirs – 6%;

The organizations involved in data gathering may be divided into three groups:

- Industry analysts (OGJ, IHS, C&C Reservoir, etc.);
- Governmental agencies;
- Operators' in-house.

Only the second category is available in public access. A brief overview of existing databases, mostly public ones, is given in Table 5.



Base Parameter	Completeness (%)
Initial pressure (est.)	86.7
Oil depth	79.5
Oil gravity	70.5
Oil porosity	68.6
Water saturation	68.4
Solution GOR	67.5
Oil formation volume factor	65.7
Oil volume 6P OIIP (est.)	65.6
Oil volume (OIIP)	65.4
Oil area	65.3
Oil thickness	65.3
Reservoir temperature	61.6
Bubblepoint pressure	56.2
Remaining oil saturation (calc.)	55.5
Oil shrinkage	53.6
Oil recovery 6P (est.)	49.1
Cumulative oil production (2005)	29.6
Abandonment pressure	27.8
Reservoirs with BHPs	26.8
Date of last pressure estimated	26.8
Proved oil reserves	22.4
Oil viscosity	18.5
Developed oil reserves	17.8
Oil produced in 2005	12.3
Oil compressibility	9.4
Oil contingent resources (P4–P6)	8.1
Permeability	4.5
Waterflood start date	2.3
Cumulative water injection (2005)	2.3
Dewpoint pressure	0.8

Figure 11. Completeness of database parameters used by Graf et al. (2011)

Table 5. Short description of existing databases

Country	Database	Content comments
USA	TORIS: Original dataset (1984), Updated (1995) Ohio dataset, Updated (2000) Kentucky dataset, Updated (2005) dataset for the Appalachian Region, Updated (2010) Wyoming dataset	Tertiary Oil Recovery Information System, gathered by Department of Energy, contains a number (ca. 60) of reservoir parameters and development details over several thousands US reservoirs
UK	Oil and gas: field data	Field and well oil, water, gas production profiles
Denmark	Danish Energy Agency	Production profiles
Int.	IHS	Miscellaneous databases
Int.	EOR OGJ	Information on basic reservoir properties (porosity, permeability, gravity, viscosity) for EOR deployment cases
Int.	C&C reservoirs	Miscellaneous databases
Norway	Diskos	• Seismic and navigational data • Well data • Production data
Norway	NPD Fact Pages	Production profiles, recoverable reserves, in-place resources

3 Discussion

3.1 Distinctive features of NCS fields relevant for IOR screening

NCS has the following distinctive features, which are of importance for IOR deployment and, hence, IOR screening point of view:

- Reservoirs with light oil, natural gas availability, and widespread waterflooding;
- All NCS EOR applications, with the exception of gas methods, were hitherto limited to platform fields and fields with combined subsea/surface facilities.
- Applications of EOR techniques, apart from gas methods, are hindered due to transportation and environmental restrictions.
- Offshore fields only. Infrastructure has a strong influence, especially, on subsea fields. As of 2013 platform, combined and subsea fields yielded ~47.8%, ~29.5% and 22.7% of oil production, respectively, with subsea wells contributing [HD25][AK26]more than half of oil production. The subsea/platform ratio is likely to continue increasing (Figure 12).

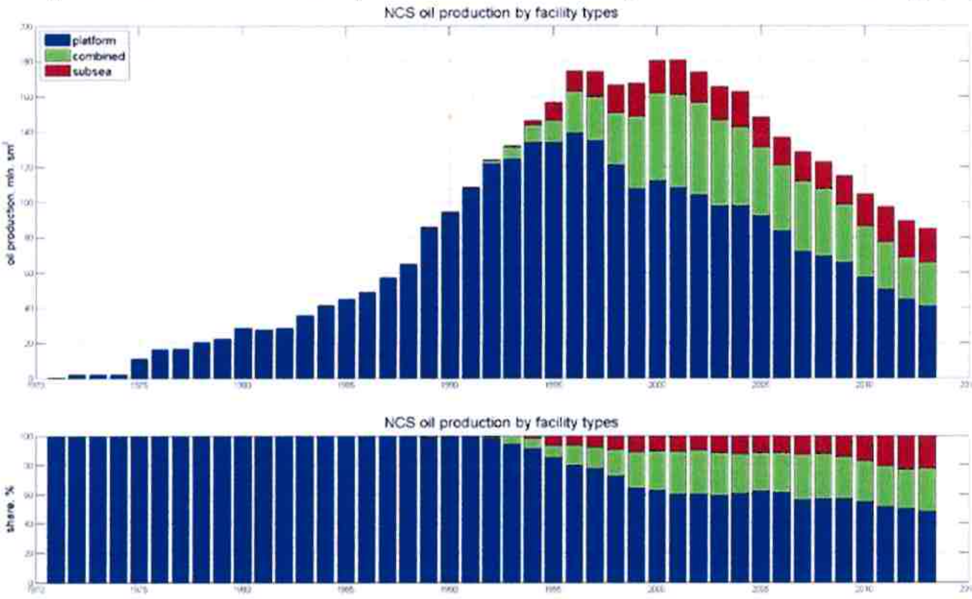


Figure 12. NCS production profile with shown shares of platform, combined and subsea fields[HD27] (based on NPD data)[AK28]

- Subsea facilities impose a number of constraints related to well flow and well maintenance (well interventions are more expensive and less frequent than for platform wells) and flow assurance. Any technique which is capable to mitigate the constraints (for instance, subsea boosting and processing) may be considered as an IOR tool. Therefore, it makes sense to extend the project's scope to consider "subsea-specific" IOR opportunities.

3.2 Relevant parameters

The following parameters are the most frequent used on IOR screening.

1. Average permeability;
2. Heterogeneity (permeability contrast; permeability variation; Dykstra-Parsons and Lorenz coefficient);

3. Fractures;
4. Structural complexity;
5. Lateral stratigraphic continuity;
6. Vertical communication;
7. Reservoir dip;
8. Original Oil In Place;
9. STOOIP density;
10. Oil viscosity;
11. Coning tendency;
12. Aquifer support;
13. Compaction;
14. Reservoir pressure;
15. Temperature;
16. Flow assurance;
17. Water depth;
18. Production facilities type: platform, combined, subsea.

3.3 Ways-forward to develop the scoring approach for NCS

1. Introduce a parameter to reflect constraints imposed by the type of production facilities[3].
2. Consider STOIIP as a scoring parameter;
3. The scoring approach can be extended by means of Fuzzy Logic membership functions (this may make the scoring procedure smoother and more flexible, particularly to assess hard-to formulate parameters);
4. Add a $\frac{[\text{STOIIP}]}{[\text{number of wells}]}$ parameter (it is likely to correlate with RF);
5. These suggestions can be tested and validated for the limited (20-30) sample of UK fields from *Wickens & Kelly (2010)*. It is not likely to take a lot of time, but would be of great use as we have at our disposal an excellent description for UK fields *(Gluyas & Hichens, (2003))* which are adjacent to NCS and, hence, are analogs to[HD29] Norwegian fields.

3.4 Possible way forward to develop / improve statistical tools for IOR/EOR screening

1. Back population of data (Graf et al., 2011) is an interesting idea that could add a significant value to any screening procedure.
2. Build up in-house synthetic database of the field cases based on the numerical simulation to:
   - duly test a methodology on a "clean" database; and
   - analyze the influence of possible data gaps.

---

[3] For instance, it may be the following scale: 0 – onshore field, 1 – platform, 2 – combined subsea/platform, 3 – all-subsea;

Abbreviations

NCS – Norwegian Continental Shelf
(O)RF – (oil) recovery factor
STOIIP – stock-tank oil initially in place oil initial in place
IOR – improved oil recovery
EOR – enhanced oil recovery
RCI – reservoir complexity index

References[HD30]

Alvarado, V., and Manrique, E. (1996) Enhanced Oil Recovery: An Update Review, http://www.mdpi.com/1996-1073/3/9/1529

Alvarado, V., Ranson, A., Hernandez, K., Manrique, E., Matheus, J., Liscano, T., and Prosperi, N. (2002) Selection of EOR/IOR Opportunities Based on Machine Learning, conference paper SPE 78332 presented at European Petroleum Conference, Aberdeen, United Kingdom, 29-31 October 2002.

Babushkina, E.V., Rusakov, V.S., Rusakov, S.V., Shchipanov, A., Berenblyum, R.A., and Khrulenko, A.A. (2013) Forecasting IOR/EOR Potential Based on Reservoir Parameters, presented at IOR 2013 – 17th European Symposium on Improved Oil Recovery held in St. Petersburg, Russia, 16-18 April 2013.

Bygdevoll, J. (2010) Introduction to Reservoir Complexity Index (RCI), NPD presentation.

Dickson, J. L., Leahy-Dios, A., and Wylie, P. L. (2010) Development of Improved Hydrocarbon Recovery Screening Methodologies, conference paper SPE 129768 presented at SPE Improved Oil Recovery Symposium, Tulsa, Oklahoma, USA, 24-28 April 2010.

Dromgoole, P., and Speers, R. (1997) Geoscore; a method for quantifying uncertainty in field reserve estimates, Petroleum Geoscience, 1997, Vol. 3(1), pp.1-12 http://www.geolsoc.org.uk/M20CD

Gluyas, J. G., and Hichens , H. M. (2003) United Kingdom Oil and Gas Fields Commemorative Millennium Volume, The Geological Society London, Geological Society, London, Memoirs, 2003, 20:17-59, doi:10.1144/GSL.MEM.2003.020.01.04

Graf, T. et al. (2011) Candidate Selection Using Stochastic Reasoning Driven by Surrogate Reservoir Models, SPE Reservoir Evaluation & Engineering, August 2011, p. 433 – 442, SPE 136373-PA-P.

Horikx, J. et al. (2013) A Specific Way of Assessing Target Recovery Factors (Chalk Oil Fields), conference paper IPTC 16925-MS presented at International Petroleum Technology Conference, Beijing, China, 26-28 March, 2013.

Ibatullin, R. R., Ibragimov, N. G., Khisamov, R. S., Podymov, E. D., and Shutov, A. A. (2002) Application And Method Based On Artificial Intelligence For Selection Of Structures And Screening Of Technologies For Enhanced Oil Recovery, conference paper SPE 75175-MS presented at SPE/DOE Improved Oil Recovery Symposium, Tulsa, Oklahoma, 13-17 April, 2002.

Lake, L.W., and Walsh, M.P. (2008) Enhanced Oil Recovery (EOR) Field Data Literature Search, http://www.ens.dk/sites/ens.dk/files/undergrund-forsyning/olie-gas/felter-produktion-danmark/foroeget-indvinding-eor/EOR_Report_Final.pdf

Lu, X., Sun, S.-Q., Xu, J., Wu, W., Zhai, P., Wei, Y., and Li, G. (2011[HD31][AK32]), A Novel Method for Life-Cycle Production Performance Forecast Based on Dynamic Analogs, conference paper IPTC 14479 presented at International Petroleum Technology Conference, Bangkok, Thailand, 15-17 November, 2011.

Manrique, E.J., Izadi, M., Kitchen, C., and Alvarado, V. (2009) Effective EOR Decision Strategies With Limited Data Field Cases Demonstration, SPE Reservoir Evaluation & Engineering, August 2009, p. 551 – 561, SPE 113269-PA.

Nishikiori, N., Sugai, K., Normann, C., Onstein, A., Melberg, O., and Eilertsen, T. (2008) An Integrated workflow for gas injection EOR and a successful application for a heterogeneous sandstone reservoir in the Southern North Sea, conference paper IPTC 12025-MS presented at International Petroleum Technology Conference held in Kuala Lumpur, Malaysia, 3-5 December 2008.

NPD, Factpages http://factpages.npd.no/

NPD (2005) The petroleum resources on the Norwegian Continental Shelf. Resource report. http://npd.no/Templates/OD/Article.aspx?id=456&epslanguage=en

Smalley, P. C., Ross, A. W., Brown, C., Moulds, T. P., and Smith, M. J. (2009) Reservoir Technical Limits: A Framework for Maximizing Recovery From Oil Fields, SPE Reservoir Evaluation & Engineering, 04'2009, p. 610 – 629, SPE 109555-PA.

Surguchev, L. M., Zolotukhin, A. B., and Bratvold, R. B. (1992), Reservoir Characterization and Modeling Supported by Expert Knowledge Systems, conference paper SPE 24279-MS presented at European Petroleum Computer Conference, Stavanger, Norway, 24-27 May, 1992.

Surguchev, L. M., Reich, E.-M., Berenblyum, R, and Shchipanov, A. (2011) A Multistage Approach to IOR/EOR Screening and Potential Evaluation, conference paper SPE 143789-MS, presented at Brasil Offshore Conference and Exhibition, Macaé, Brazil, 14 – 17 June 2011.

Surguchev, L., and Li, L. (2000) IOR Evaluation and Applicability Screening Using Artificial Neural Networks, conference paper SPE 59308 presented at SPE/DOE Improved Oil Recovery Symposium, Tulsa, Oklahoma, 3 – 5 April 2000.

Wickens, L. M., and Kelly, R. (2010) Rapid Assessment of Potential Recovery Factor: A New Correlation Demonstrated on UK and USA Fields, conference paper SPE 134450 presented at SPE Annual Technical Conference and Exhibition (ATCE), Florence, Italy, 19-22 September 2010.

Zerat, M.M. et al. (2011) Bayesian Network Analysis as a Tool for Efficient EOR Screening, Enhanced Oil Recovery, conference paper SPE 143282-MS presented at SPE Enhanced Oil Recovery Conference, Kuala Lumpur, Malaysia, 19 – 21 July 2011.