

Comparative Analysis of Water Drive, Gas Drive and Natural Drive Mechanism for Oil Production using Alwyn North Field as a Case Study

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Abstract—In-situ Crude oil can be produced through several drive mechanisms of which the choice of specific drive mechanism is dependent on several key performance tools. This study examines the Alwyn North field and presents a comparative analysis for producing crude oil using water drive, gas drive and natural drive or depletion drive. The Eclipse Simulator was used to simulate different scenarios of well placement and performance tools such as FOPR, FPR, FWCT, FGOR and FOE was used during simulation to compare the outcomes of the well placement. Economic analysis which is key in decision making was carried out using economic tools such as Gross Profit Margin (GPM), Net Present Value (NPV), Payback Period, Internal Rate Return (IRR) and Profitability Index (PI). The payback period for water injection was 2.1years and 1.99years for gas injection. IRR was 53% and 48% for water and gas injection development schemes respectively and Profitability Index for water injection was 1.73 and 1.36 for gas injection. These economic tools helped to arrive at a conclusion of best drive mechanism for the production of the field.

Index Terms—Water Drive, Gas Drive, Natural Drive, CNPV, GPM, IRR, PI, Payback Period, FOPR, FPR, FWCT, FGOR, FOE, Eclipse Simulator.

I. INTRODUCTION

The movement of reservoir fluids (gas, oil and water) from the reservoir to the wellbore is as a result of the driving mechanism. The reservoirs nature is understood better and effective predictions can be made by evaluating how these drive mechanisms control the fluid behavior in-situ. Producing these reservoir fluids by the natural energy of the reservoir is known as Primary recovery [9].

The Schlumberger oil field glossary [8] classified reservoir drive mechanism into four, which are;

- 1) Gravity drainage
- 2) Combination drive
- 3) *Water drive (edge water drive and bottom water)*
- 4) *Gas drive (gas cap or solution gas drive)*

However, selection of recovery scheme to embark on during oil production is dependent on many factors of which economics is very important.

Gas drive mechanism: This can be analyzed in different forms, either by solution gas drive (or dissolved gas drive) or by the gas cap drive. Solution gas drive is when the

dissolved gas in the oil expands and its energy is used to support the production of the reservoir fluid. In some cases, where the vertical permeability is high, the gas can migrate upwards to form a secondary gas cap. Most times primary, secondary and tertiary recovery mechanism using gas drive are confused by scholars. Primary recovery is the use of the typical reservoir energy to produce from the reservoir to the wellbore, so gaslift can be classified under primary recovery. Secondary recovery is aided by an artificial pressure which is done by injecting gas (immiscible) into the reservoir to use its expansion energy to produce the crude. The tertiary recovery is also an injection process but here the gas is miscible with the reservoir fluid. The gas cap drive occurs in a reservoir identified to contain a gas cap with little or no water drive. Production is enhanced by the expansion of the gas cap and these type of reservoirs are characterized with slow decline in reservoir pressure [10].

Water drive mechanism: Most times more than one drive mechanism occurs at the same time, however, in water drive the water advances to take the place of the oil, either through the edge water or bottom water [2]. It is so far seen as the most effective drive mechanism but differs from field to field depending on the economics and characteristics of the reservoir. Also water injection can be confusing in analogy by scholars on the basis of primary or secondary mechanism. However, water injection is said to be primary if its aim of injection into the aquifer is for pressure maintenance, but secondary if its injection is for area sweep towards the producing well.

Eclipse Simulator: This is a Schlumberger reservoir simulator used for black oil, thermal, compositional and streamline simulations. It is said to be a benchmark for commercial simulators for over 25years and give a close representation of the reservoir.

The Black Oil model used in eclipse makes the following assumptions:

- 1) *3 components (in standard conditions)*
Oil & gas compositions are assumed constant over time
Oil, water & gas density is assumed constant over time
- 2) *3 phases (in reservoir conditions)*
Oil is a mixture of "oil" & "gas" components
Gas corresponds to "gas component"
Water corresponds to "water component"
- 3) *3 flow equations*

A. Oil equation

Corresponds to the "oil component" contained in the oil phase.

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B. Gas equation

Corresponds to the "gas component" contained in the oil & gas phases.

C. Water equation

Corresponds to the "water component" contained in the water phase [6].

The basics of Material Balance Equation, MBE is used for simulation:

$$N = \frac{N_p \{B_o + [R_p - R_s] B_g\} + W_p B_w - W_e B_w - W_i B_w - G_i B_g}{B_o - B_{oi} + (R_{si} - R_s) B_g + m B_{oi} \left[\frac{B_g - B_{gi}}{B_{gi}} \right] + (1+m) B_{oi} \left(\frac{C_w S_{wi} + C_f}{1 - S_{wi}} \right) \Delta P}$$

$$InjectionDrive = \frac{W_i B_w + G_i B_g}{N_p [B_o + (R_p - R_s) B_g]} \quad [5]$$

II. AIMS AND OBJECTIVES

The aim of this study is to propose a development plan for the Brent East reservoir in the Alwyn Field.

The following are objectives of this work:

- 1) Perform a natural depletion study
- 2) Perform a water injection study
- 3) Perform a gas injection study
- 4) Recommend the strategy to maximize the total hydrocarbon production and minimize the development cost in \$/bbl.

III. LITERATURE REVIEW

The Alwyn North Field was discovered in 1974 in the South Eastern part of the East Shetland Basin in the UK North Sea, about 140 km East of the near most Shetland Island and about 400 km North East of Aberdeen. The Alwyn field lies respectively 4 and 10 km south of Strathspey and Brent field, 7 km east of Ninian field, and 10 km north of Dunbar field. The water depth is around 130 m. The field is in the UKCS Block 3/9 and extends northward into the Block 3/4.

The structure of Alwyn Brent East Block is generally an eroded monoclinial, with Base Cretaceous Unconformity (BCU) setting east and south limit, Spinal Fault setting west limit (separating Brent east from north and central west blocks), and a fault with sometimes very small throw setting north limit.

East structure under BCU is quite complicated, and described under the generic term of slumps.

In the Brent East panel, the oil zone is in a stratigraphic trap, created by the erosion unconformity to the east, by a north-south fault to the west (between A-1 and A-2 wells) and by a transverse fault to the north.

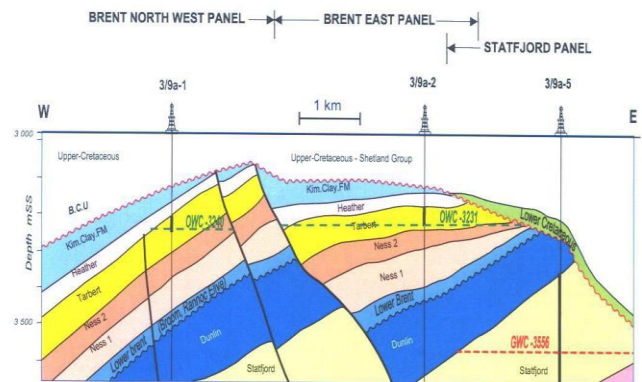


Fig. 1. Brent Geological Cross Section.

Mehdi identified three energies which aid the flow of oil into wells as initial pressure, water drive and gravity. From his analysis of water drive, gas drive and water alternating gas (WAG) injection, water drive using 5-spot pattern model proved to produce optimum [4].

Petrowiki was more elaborate on forms which gas injection could be done based on its source. The following was listed:

- 1) Reinjecting produced gas into existing gas cap
- 2) Injecting gas into oil reservoirs of separated produced gas to maintain pressure
- 3) Injection of gas to prevent oil migration to gas cap
- 4) Injection of gas into under saturated oil reservoirs to swell the oil and increase recovery
- 5) To enhance high shrinkage, volatile oil and gas cap reservoirs with retrograde gas condensate recovery.

Which shows that making gas injection a choice of enhancement for oil recovery is dependent on many parameters such as source of gas, oil property, economics, etc. [7]

Julius and Benson in their search for a way to reduce the water cut of a Niger Delta field with weak aquifer flooded since beginning of production. They simulated using gas injection, water alternating gas (WAG) injection and gas alternating water (GAW) injection and the gas injection proved to be the most economical and reduced the water cut. This research highlighted another reason for enhancing recovery using gas [3].

F. David Martin also confirmed that water injection could be done with the aim of either disposing brine water, pressure maintenance when gas cap and aquifer expansion is not sufficient or to water flood oil after primary recovery. His work explained that water injection is a dominant secondary recovery process accounting for about 50% of US current oil production [1].

IV. METHODOLOGY

The following appraisal wells were drilled:

- 1) 2 vertical wells (A2 and A4)
- 2) 2 deviated wells (N2 and N3)

N3 characterized the northern part of the field where an important oil log was confirmed mainly in the Tarbert units.

N2 located to the West did not produce any oil and only encountered the aquifer, which does seem to be active. The water salinity in the reservoir is about 17,000 ppm.

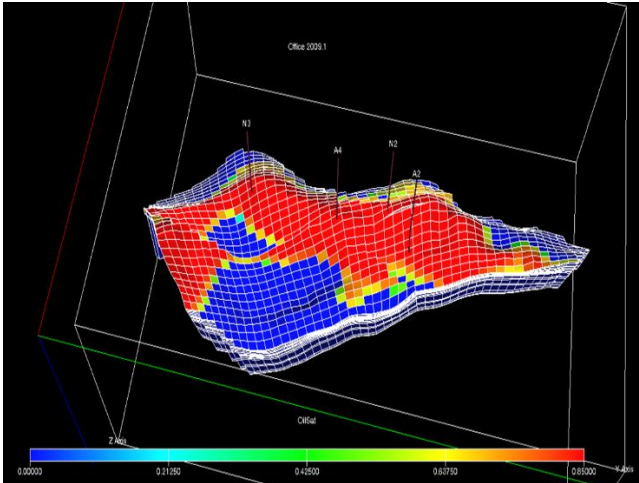


Fig. 2. Representation of Appraisal wells on Eclipse Simulator.

From the well test data, the reservoir was characterized.

TABLE I: WELL TEST DATA

Parameters	Value
Reservoir Thickness (H)	64meters (210ft)
Transmissivity (KH)	42863.0944 mD.ft
Oil Permeability (K _o)	204.139136 mD
Water permeability (K _w)	63.79348 mD
Absolute Permeability (K _{abs})	255.17392 mD
Productivity Index (PI)	41.7544317 bbl/day/psi

The PVT was carried out showing the following values:

TABLE II: PVT TEST DATA

Properties	Values
Initial Pressure Pi before	446psi
Pressure injection	340psi
Saturation Pressure	258.2psi
Initial oil formation volume factor	1.61 rb/stb
Oil formation volume factor	1.64 rb/stb
Formation volume factor at saturation pressure	1.69 rb/stb
Gas oil ratio	206.9 v/v
Viscosity of oil	0.4cp
Viscosity of oil at 340bars	0.35cp
Viscosity of saturated oil	0.31cp
Viscosity of water at 112c	0.35cp
Viscosity of water at 50c	0.31cp

A. Hand Calculations:

1) Natural Depletion

Oil Initially in Place = **41904434 Sm³**

$$\text{Recovery Factor (RF)} = \frac{N_p}{N} = \frac{(B_{oi} \cdot C_o)(P_2 - P_1)}{B_o}$$

$$\text{RF} = \frac{1.61(1.758 \times 10^{-4})(446 - 100)}{1.64}$$

$$= 0.0597 = 5.97\%$$

OIL PRODUCTION

$$\text{NPD} = N \times \text{R.F}$$

$$N_{PD} = 41904434 \times 0.0597 = \mathbf{2501694.71 \text{ Sm}^3}$$

2) Water Injection (Flooding)

Recovery Factor Using Water Injection

Recovery Efficiency

$$E = E_A \cdot E_D \cdot E_Z$$

$$E_A = 0.98 \quad E_Z = 0.75 \quad E_D = 0.741$$

$$E = 0.741 \times 0.98 \times 0.75 = 0.545$$

Cumulative Oil Production by Water Injection

$$N_{pwi} = \text{OOIP} \times E$$

$$N_{pwi} = 41904434 \times 0.545 = \mathbf{22419982.66 \text{ Sm}^3}$$

Production Plateau Rate = (OOIP · EURF)/365

$$= (41904434 \times 0.545 \times 0.15) / 365$$

$$= 9385.45 \text{ Sm}^3/\text{day}$$

3) Number of Wells

Number of Producing Wells

$$= (\text{Production Plateau Rate}) / (\text{Average Oil Withdrawal})$$

$$= 9385.45 / 1800$$

$$= \mathbf{6 \text{ wells}}$$

Number of Injection Wells

$$= (\text{Production Plateau Rate}) / (\text{Average Water Withdrawal})$$

$$= 9385.45 / 3000$$

$$= \mathbf{3 \text{ wells}}$$

TABLE III: HAND CALCULATION SUMMARY

Parameters	Value
OOIP	41904434 Sm ₃ (263578890 bbl)
RF (Natural Depletion)	5.97%
RF (Water Injection)	54.5%
Plateau production rate	9384.45 Sm ₃ /day (59028.19 bbl/day)
No. of Producers (water injection)	6 wells
No. of Injectors (water injection)	3 wells
No. of Producers (Gas injection)	7 wells
No. of Injectors (Gas injection)	4 wells

The wells were placed at the following positions with respect to the constraints listed below during this study.

In the water injection case, the field was developed using 9 wells which includes the existing four wells and 5 new wells.

TABLE IV: THE WELL PLACEMENT FOR WATER INJECTION CASE

Name	Location	Perforation	Orientation	Status
N3	20, 13	4, 4	Horizontal	Producer
A4	12, 21	3, 3	Horizontal	Producer
N2	11, 26	4, 4	Horizontal	Producer
A2	6, 28	2, 5	Vertical	Producer
IPS_P2	14, 2	2, 11	Vertical	Producer
IPS_W2	21, 8	3, 11	Vertical	Injector
IPS_W3	17, 17	3, 10	Vertical	Injector
IPS_P1	5, 32	2, 4	Vertical	Producer
IPS_W1	5, 35	3, 11	Vertical	Injector

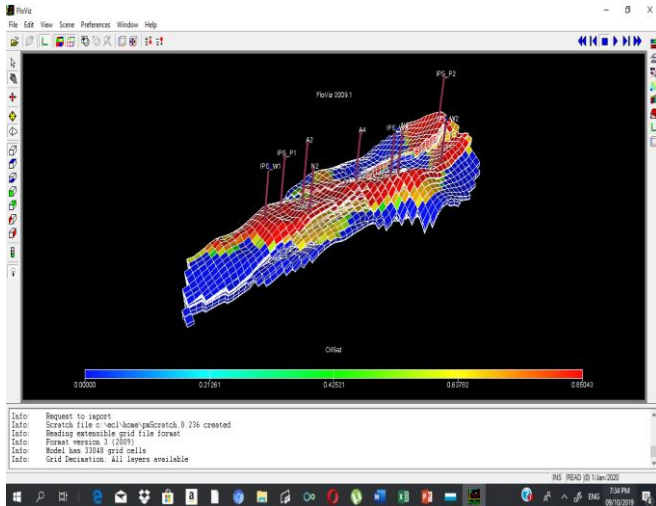


Fig. 3. Representation of Water injection case on Eclipse Simulator.

TABLE V: THE WELL PLACEMENT FOR GAS INJECTION CASE

Name	Location	Perforation	Orientation	Status
N3	20, 13	4, 4	Horizontal	Producer
A4	12, 21	4, 4	Horizontal	Producer
N2	11, 26	4, 4	Horizontal	Producer
A2	6, 28	1, 4	Vertical	Producer
P1	9, 23	1, 6	Vertical	Producer
P2	11, 2	2, 10	Vertical	Producer
P3	14, 2	2, 11	Vertical	Producer
G1	1, 45	2, 6	Vertical	Injector
G2	20, 3	1, 7	Vertical	Injector
G3	3, 30	1, 7	Vertical	Injector
G4	5, 2	1, 7	Vertical	Injector

B. General Constraints

- 1) BHP of 260 bars
- 2) GOR of 1500 Sm³ (9435 bbl) maximum allowable
- 3) Water cut of 90% maximum allowable
- 4) Minimum economic rate for each well was 100 Sm³/d (629 bbl/d)
- 5) Minimum economic rate for the field was 1000 Sm³/d (6290 bbl/d)
- 6) Fracture pressure 480bars

C. Water Injection (flooding) constraints

- 1) Maximum water injection rate is 3000 Sm³/d (18,870 bbl/d)
- 2) Maximum total water injection available 15000 Sm³/d (94,350 bbl/d)
- 3) Production plateau rate of 7200 Sm³/d (45,288 bbl/d)

D. Gas Injection Constraints

- 1) The maximum gas injection rate is 800,000 Sm³/d

(5.03 MMbbl/d) per well. The maximum total gas injection available is 3,200,000 Sm³/d (20.1MMbbl/d).

- 2) Control the injection in voidage replacement.

IV. RESULT AND FINDINGS

Field performance comparison of the two scenarios using Eclipse Simulator showed variations which will help in drawing a conclusion.

The following performance data were acquired during simulation:

- 1) Field Gas Oil Ratio, FGOR
- 2) Field Water Cut, FWCT
- 3) Field Oil Production Rate, FOPR
- 4) Field Pressure, FPR
- 5) Field Oil Efficiency, FOE

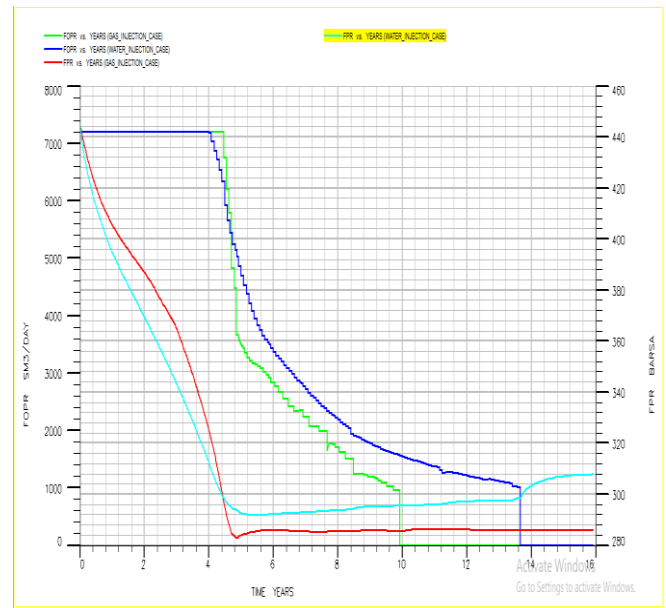


Fig. 4. Field Pressure and Field Production Rate using Eclipse.

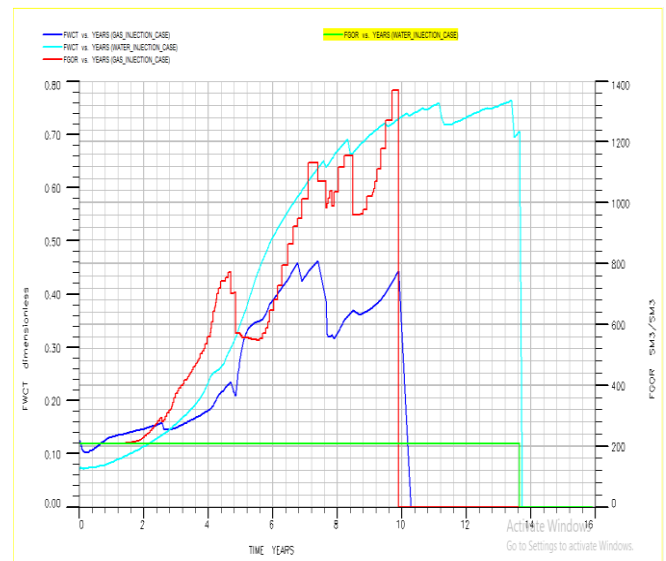


Fig. 5. Field Water Cut and Gas Oil Ratio using Eclipse.

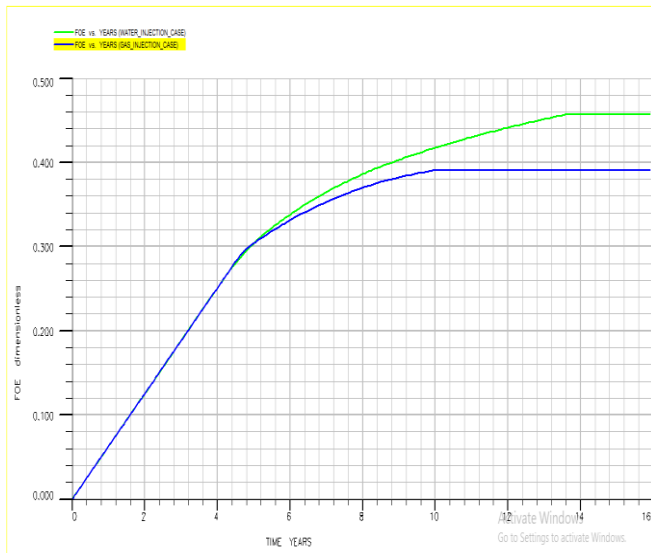


Fig. 6. Field Oil Efficiency using Eclipse simulator.

Using the following cost estimates, the economic analysis of this simulation was computed.

C. CAPEX & OPEX

- Brent oil barrel price: 65 US\$/bbl.
- Treatment and production facilities platform: 700 MM\$
- Drilling & accommodation platform with 40 platform slots: 250 MM\$
- Based on the lifting cost of oil per barrel: 8.5 \$/bbl

D. Drilling Cost Per Well

- Secondary platform: 250 MM\$ Drilling cost per well:
- Deviated from a platform: 12.0 MM\$
- Horizontal from a platform: 16.0 MM\$
- Gas injection compressor: 44.2 MM\$

Production Variables	Water Injection	Gas Injection
OOIP (bbl.)	263,578,890	263,578,890
Recovery factor (%)	46	39
Ultimate recovery (bbl.)	113,614,958.50	95,629,958.39
CAPEX (US\$)	1,022,000,000.00	1,090,200,000
OPEX (US\$)	966,000,000	813,000,000
Gross revenue (US\$)	7,384,972,305	6,215,947,295
Gross profit margin (US\$)	6,362,972,305	4,310,000,000
Profitability index	1.73	1.36
Cumulative Net present value (US\$)	1,767,739,224	1,485,445,466
Internal rate of return (%)	53	48
Payback period (years)	1.99	2.1

V. CONCLUSION

The following conclusion were drawn from the analysis of the Alwyn Field.

- 1) Water and Gas Injection cases are both economically feasible.
- 2) The water injection has a larger investment.
- 3) Water Injection maximizes recovery at 46%.
- 4) Based on economic analysis, the water injection case is a better development option for the Alwyn Field.

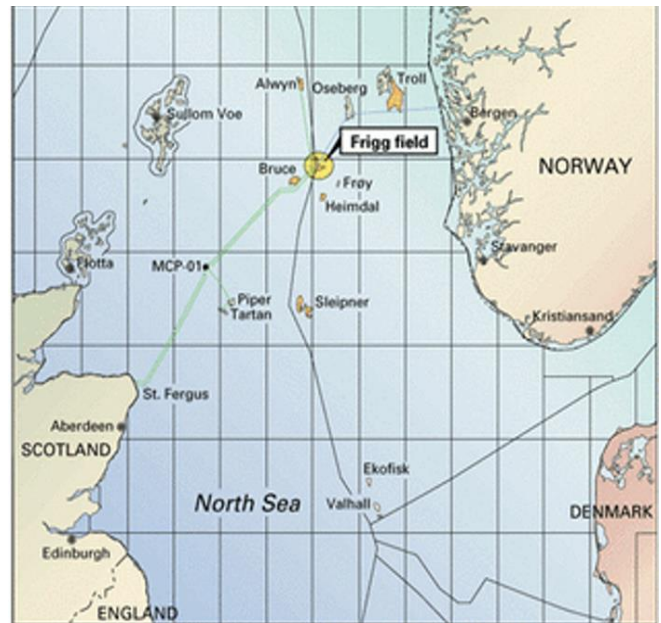
VI. RECOMMENDATION

This research work based its criteria for development on economics which may not always be the case. Decisions on development can be influenced by Government Policies, Security status, Company ideology, etc.

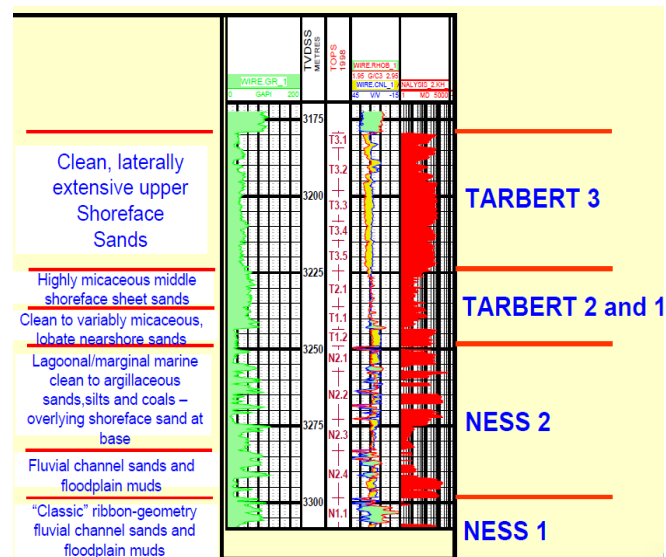
The hand calculation is necessary for result comparison and to guide you during the simulation process.

This work can be used as a guide for further research and use of simulators such as Eclipse, Olga, etc.

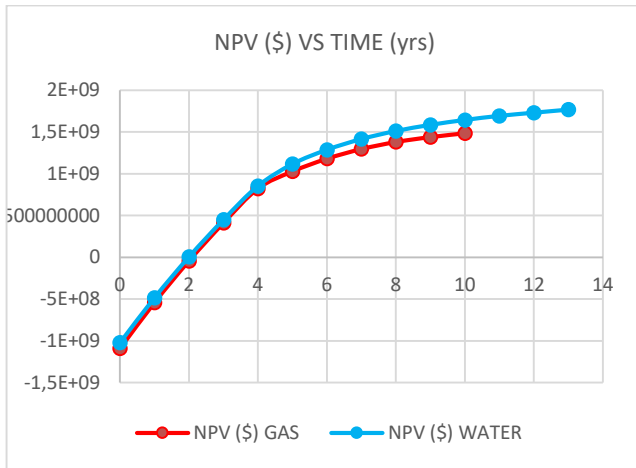
APPENDIX



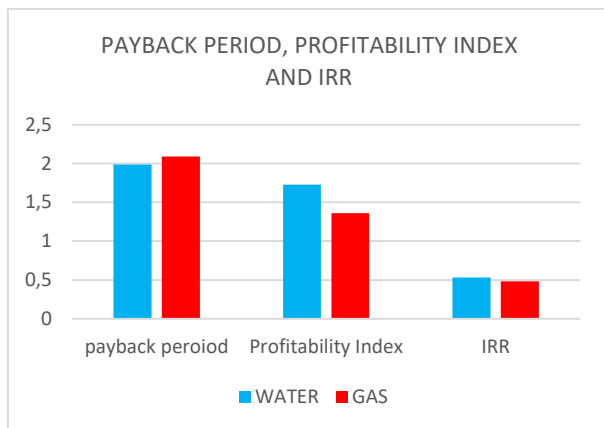
Appendix 1. Alwyn north field, UK north sea



Appendix 2. Log diagram of Brent East reservoir



Appendix 3. Plot of Net Present Value vs Time



Appendix 4. Plot of Payback period, profitability index and IRR

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