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A database and workflow integration methodology for rapid evaluation and selection of Improved Oil Recovery (IOR) technologies for heavy oil fields

Roozbeh Kalateh[a,b], Lynne Ogg[b], Matanat Charkazova[b], Dimitrios I. Gerogiorgis[a,*]

[a] Institute for Materials and Processes (IMP), School of Engineering, University of Edinburgh, The King's Buildings, Edinburgh EH9 3FB, UK
[b] Ingen-Ideas Ltd, 111 Gallowgate, Aberdeen AB25 1BU, UK

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A B S T R A C T

Conventional crude oil is the currently dominant but a non-renewable energy resource. Despite the development and improvement of alternative energy technologies, there is still a large gap between the capability of renewable energy systems to capture and reliably supply power, and the ever-increasing global energy demand requirements. Therefore, until technological innovations facilitate sufficient energy generation through alternative fuels, other means of sustaining crude oil production, such as Improved Oil Recovery (IOR) methods, must be systematically explored. Beyond increasing production of conventional oil, IOR methods can effectively facilitate the extraction of oil from unconventional reservoirs, such as heavy oil fields. This capability is of high strategic importance due to the considerably large size of global heavy oil reserves.

There are several IOR technologies available, but each of them is suitable only for certain oil field types. The aim of this paper is to illustrate an alternative, low-cost, quick screening method which is competitive to more technically laborious and costly methods for selecting the most suitable technology for a given heavy oil extraction project, using a limited dataset. A two-stage technology screening method is hereby proposed: the first stage is based on previous project literature data evaluation, and the second stage is based on simple empirical oil production correlation methods (such as the Marx & Langenheim model) coupled with Ingen's RAVE (Risk and Value Engineering) and Schlumberger's PIPESIM software applications. The new method can achieve reasonably accurate results and minimise cost and time requirements during the preliminary stages of an oilfield development project, as evidenced via a comprehensive case study.

Abbreviations

AMPCP	All-Metal Progressive Cavity Pumps
API	American Petroleum Institute
ASP	Alkali-Surfactant-Polymer Flooding
BHP	Bottom Hole Pressure
BPD	Barrels Per Day
CAPEX	Capital Expenditure
CHOPS	Cold Heavy Oil Production with Sand
CSS	Cyclic Steam Stimulation
EOR	Enhanced Oil Recovery
ESP	Electrical Submersible Pump
GBP	Pounds Sterling
GOR	Gas to Oil Ratio
HASD	Horizontal Alternating Steam Drive
HSP	Hydraulic Submersible Pump
HWF	Hot Water Flooding
IAM	Integrated Asset Model
IFT	Interfacial Tension
IM CO_2	Immiscible Carbon Dioxide Flooding
IM HC	Immiscible Hydrocarbon Flooding
IM N_2	Immiscible Nitrogen Flooding
IM WAG	Immiscible Water Alternating Hydrocarbon Gas Flooding
IOR	Improved Oil Recovery
M HC	Miscible Hydrocarbon Flooding
Mid	Medium
M&L	Marx and Langenheim model
M&S	Myhill and Stegemeier model
M&V	Mandl and Volek model

* Corresponding author: Tel.: +44 131 6517072.
E-mail address: D.Gerogiorgis@ed.ac.uk (D.I. Gerogiorgis).

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Nomenclature

Symbol	Parameters
a	Costing constant
A	Swept reservoir area, ft^3
b	Costing constant
C	Heat capacity of the reservoir rock, $BTU.ft^{-3}.°F^{-1}$
C_O	Specific heat capacity of oil, $BTU.lb^{-1}.°F^{-1}$
CF	Cash flow, \$
C_r	Specific heat capacity of rock, $BTU.lb^{-1}.°F^{-1}$
C_w	Specific heat capacity of water, $BTU.lb^{-1}.°F^{-1}$
CX_m	Capital cost of equipment, \$
D	Thermal diffusivity of reservoir rock, $ft^3.h^{-1}$
H	Formation thickness, ft.
h_{hf}	Enthalpy of hot fluid, $BTU.lb^{-1}$
k	Thermal conductivity of rock, BTU. $ft^{-1}.h^{-1}.°F^{-1}$
M_{hf}	Mass flowrate of hot fluid, $lb.h^{-1}$
P	Pressure, psi
Q	Thermal energy, 10^6. $BTU.h^{-1}$
Q_L	Heat loss during production, %
r	Interest rate, %
S_O	Oil saturation, %
S_{Or}	Residual oil saturation, %
S_w	Initial water saturation, %
t	Time, h
T_{amb}	Ambient temperature, °F
T_{hf}	Temperature of hot fluid, °F
T_r	Reservoir temperature, °F
T_w	Production well bottomhole temperature, °C
x	Dimensionless time
Z	Size parameter
ΔT	Temperature difference, °F
ϕ	Porosity, %
ρ_o	Oil density, $lb.ft^{-3}$
ρ_r	Reservoir rock density, $lb.ft^{-3}$
ρ_w	Water density, $lb.ft^{-3}$
μ	Viscosity, cP

NPV	Net Present Value
OPEX	Operating Expenditure
PCP	Progressive Cavity Pump
PVT	Pressure-Volume-Temperature
SAGD	Steam Assisted Gravity Drainage
SCF	Standard Cubic Feet
SF	Steam Flooding
SRP	Sucker Rod Pump
STB	Standard Barrel
RAVE	Risk And Value Engineering
THAI	Toe-to-Heel Air Injection
WC	Water Cut
WF	Water Flooding
WAG	Water Alternating Gas Flooding

1. Introduction

As societies become more prosperous, the demand for energy and consequently oil has increases incessantly. However, as the light oil reserves mature and are gradually depleted, other energy resources are needed so as to replace them in order to maintain energy prices at reasonable levels. Considering the cost and performance potential of currently available renewable (solar, wind, wave, tidal) energy generation technologies, other less cost-efficient fossil fuels (bitumen, heavy oil) will be necessary to supplement the production of light oil as the primary energy source which can fulfill the high global energy as well as petrochemical product demand requirements. Despite the lower depth of heavy oil reservoirs compared to conventional oil reservoirs, heavy oil specifications do not render it capable of flowing naturally from the reservoir to the surface, due to the comparatively lower reservoir pressure, higher viscosity and higher density, as illustrated in Table 1 [9,30]; consequently, external assistance is required so as to facilitate crude heavy oil production. These technologies are collectively defined as Improved Oil Recovery (IOR) methods.

Table 1
Properties of conventional oil compared to heavy oil and bitumen.

Identity	Unit	Conventional Oil	Heavy Oil	Bitumen
API Gravity	Degree	38.1	16.3	5.4
Depth	m	1567	991	373
Viscosity (25 °C)	cP	13.7	100,947	1,290,254
Viscosity (55 °C)	cP	15.7	278.3	2371
Asphalt	wt%	8.9	38.8	67
Asphaltenes	wt%	2.5	12.7	26.1
Carbon	wt%	85.3	85.1	82.1
Nitrogen	wt%	0.1	0.4	0.6
Oxygen	wt%	1.2	1.6	2.5
Sulphur	wt%	0.4	2.9	4.4
Flash Point	°C	−8	21	–
Pour Point	°C	−8	−6	23
Aluminum	ppm	1.174	236.021	21,040.03
Iron	ppm	6.443	371.05	4292.96
Nickel	ppm	8.023	59.106	89.137
Lead	ppm	0.933	1.159	4.758

Production of heavy oil through IOR is cost-intensive due to the requirement for extra Capital Expenditure (CAPEX) and Operating Expenditure (OPEX), therefore their utilisation is heavily dependent on the price of oil. Because of the macroeconomic expectation for higher oil prices due to the gradual depletion of reservoirs containing easily accessible oil, the detailed cost evaluation of IOR projects in early stages is essential towards reducing the financial and development risks. Therefore, developing reliable software tools for systematic technoeconomic evaluation of heavy oil IOR projects rapidly and accurately at the early stages can provide a significant advantage to oil producing companies over their competitors. Systematic process modelling, simulation and optimisation on the basis of first-principle models encompassing mass, heat and momentum transport phenomena have been successfully used in order to study, design and operate a wide variety of high energy intensity [12–14], power generation [26] and complex chemical reaction processes [19,20,33], particularly when the interest to maximise their high added value justifies the effort for process intensification and technoeconomic evaluation.

This paper is organised as follows: first, the concept and purpose of IOR technologies is outlined and illustrated with a detailed classification thereof. Sections 2 and 3 elaborate on evaluating the feasibility of different IOR methods by means of benchmarking oil field properties and technology performance indices against previous and current IOR projects, using an original comprehensive database. Sections 4 and 5 present the technoeconomic evaluation methodology for systematic analysis of IOR methods, which are analysed by means of a theoretical case study in order to select the method with the highest attainable profit margin. A combination of production system (heavy oil reservoir, injection and production wells) flow simulations carried out in PIPESIM [34] and empirical pressure and heat loss calculations integrated with Ingen's proprietary technoeconomic analysis software tool, RAVE [17] has been employed for the present study, thereby accomplishing a rapid and cost-effective prediction of the optimal IOR

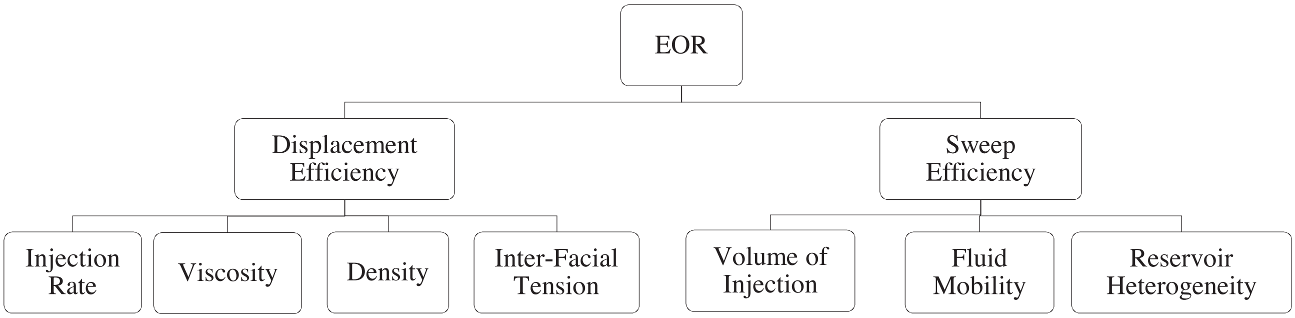


Fig. 1. Main parameters affecting oil recovery through EOR methods.

technology and the corresponding attainable heavy oil production rate.

1.1. What is IOR?

Improved Oil Recovery (IOR) methods are applied in order to facilitate or increase oil flowrate from the well, and they can be distinguished into secondary and tertiary technologies: the latter are also referred to as Enhanced Oil Recovery (EOR) methods.

During the application of secondary IOR methods, no alterations are made to physicochemical oil properties: their main objective is to either maintain the reservoir pressure or increase the pressure gradient between well bottomhole and head pressure. Accordingly, they can either be implemented right at the start of the production phase of an oil field development project, in order to ensure the highest possible reservoir pressure, or they can be applied sometime after the production has started, in order to increase the production rate. Tertiary (EOR) methods can be further distinguished into three main groups: cold (gas injection), chemical and thermal methods. Contrary to secondary IOR methods, tertiary methods alter oil properties within the reservoir in order to achieve flow enhancement. Similar to secondary IOR methods, tertiary (EOR) methods can also be applied at different stages of the project. However, due to the high cost of their installation and operation, they are normally employed for the recovery of heavy oil or incremental oil which has remained in the reservoir after the application of primary and secondary recovery methods.

Fig. 1 illustrates how enhancing displacement efficiency and sweep efficiency constitutes the main mechanisms by which oil recovery is improved through EOR method applications. Moreover, Fig. 2 presents the classification and key parameters by which oil recovery is enhanced by implementing each EOR method. A comprehensive classification of all IOR methods reviewed and compared in this study is presented in Fig. 3.

2. Artificial lift

Artificial lift is implemented in production wells in order to either increase or maintain the flowrate of crude oil. Fig. 4 depicts the classification of numerous artificial lift technologies, which are distinguished in two broad categories: pump-based and fluid-based methods. The main objective of pump-based artificial lift methods is to increase well fluid pressure by means of external forces; the operating principle of fluid-based artificial lift methods is fluid expansion and corresponding volumetric flowrate increase, which consequently reduces the hydrostatic head in the well and facilitates higher oil production flowrates.

2.1. Artificial lift methods: comparison and selection

The suitability of a particular artificial lift method is strongly dependent on the reservoir conditions and oil properties. The most important parameters which affect the selection procedure are listed below:

- Reservoir depth
- Production capacity
- Operating temperature
- Oil API gravity and viscosity
- Solid and gas content of produced fluid
- Deviation of the well
- Location of the field

Each artificial lift method has operational limits based on one or more of the foregoing parameters. For example, Sucker Rod (SRP) pumps are limited to onshore implementations and cannot be installed in offshore oil field development projects. Therefore, it is essential to identify and consider the oil field and wells configuration before analysing the applicability and performance of IOR methods under realistic oil production conditions.

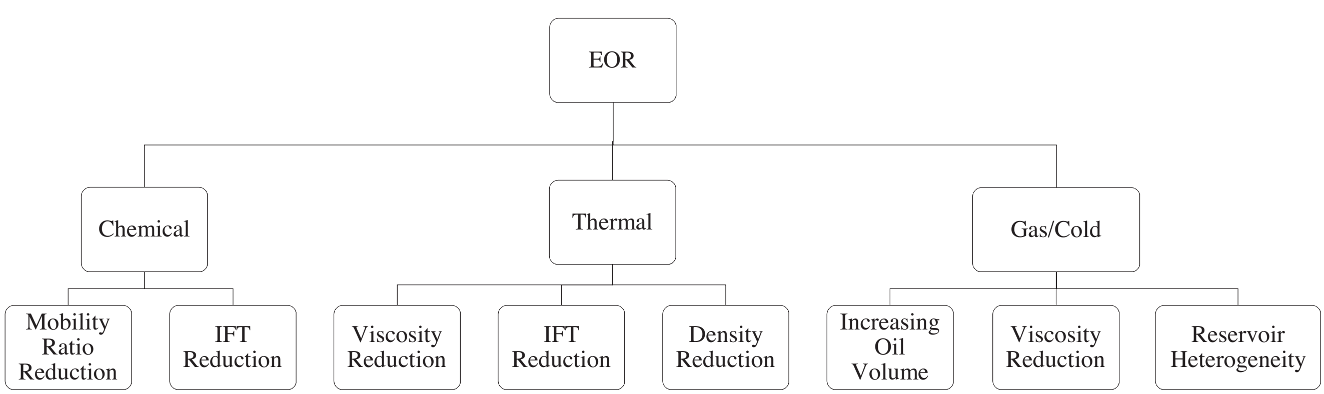


Fig. 2. Main effects of each EOR category.

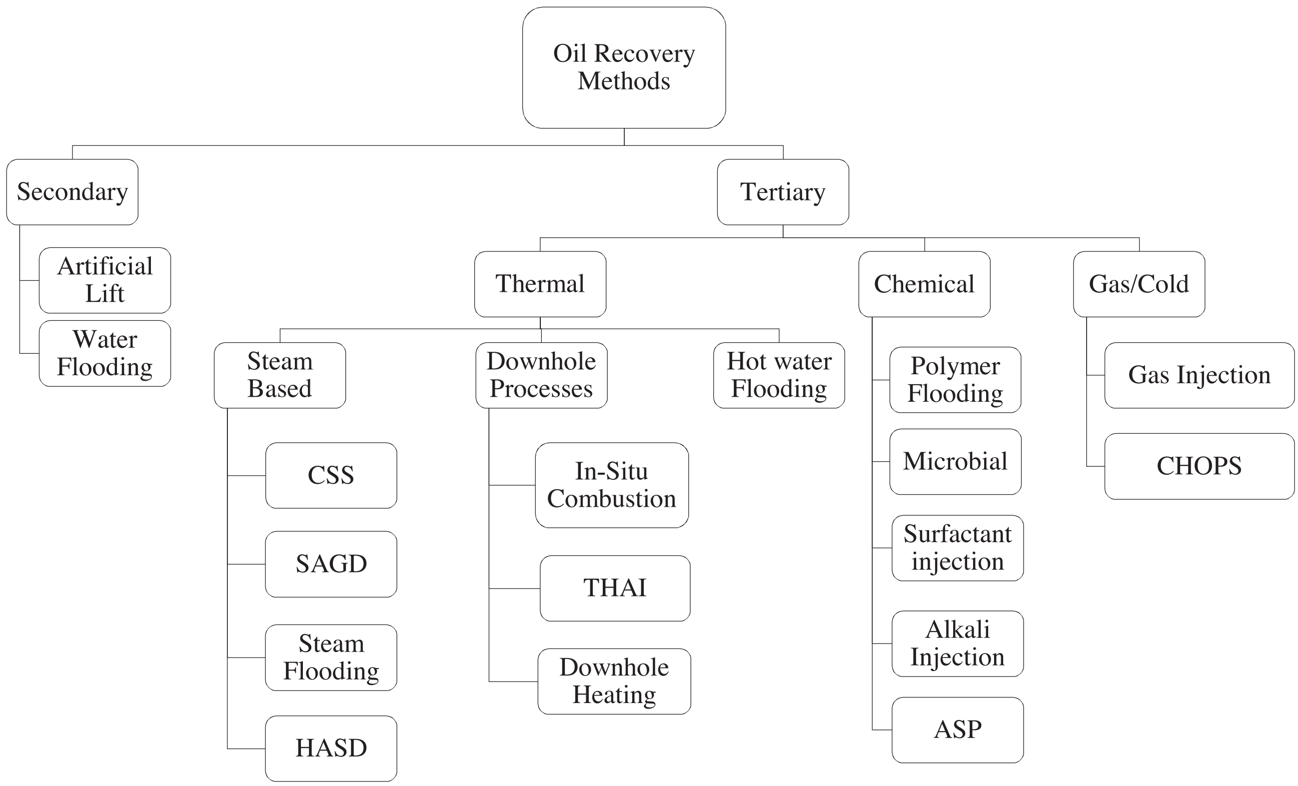


Fig. 3. List and classification of IOR methods.

The applicability boundaries of pump-based methods used in commercial artificial lift operations according to industrial standards is presented in Table 2 [7,16,25]; the operability of each method can accordingly be determined by developing a database of tabulated operational parameters.

Once the applicability of each suitable method has been confirmed, the corresponding performance indices must be compared in order to eliminate the least promising ones. The most important parameters and operational issues which affect artificial lift performance and consequently influence this preliminary screening procedure are listed below:

- Energy efficiency
- Corrosion probability
- Emulsion formation
- Foam formation
- Wax existence
- Asphaltenes existence
- Maintenance procedure

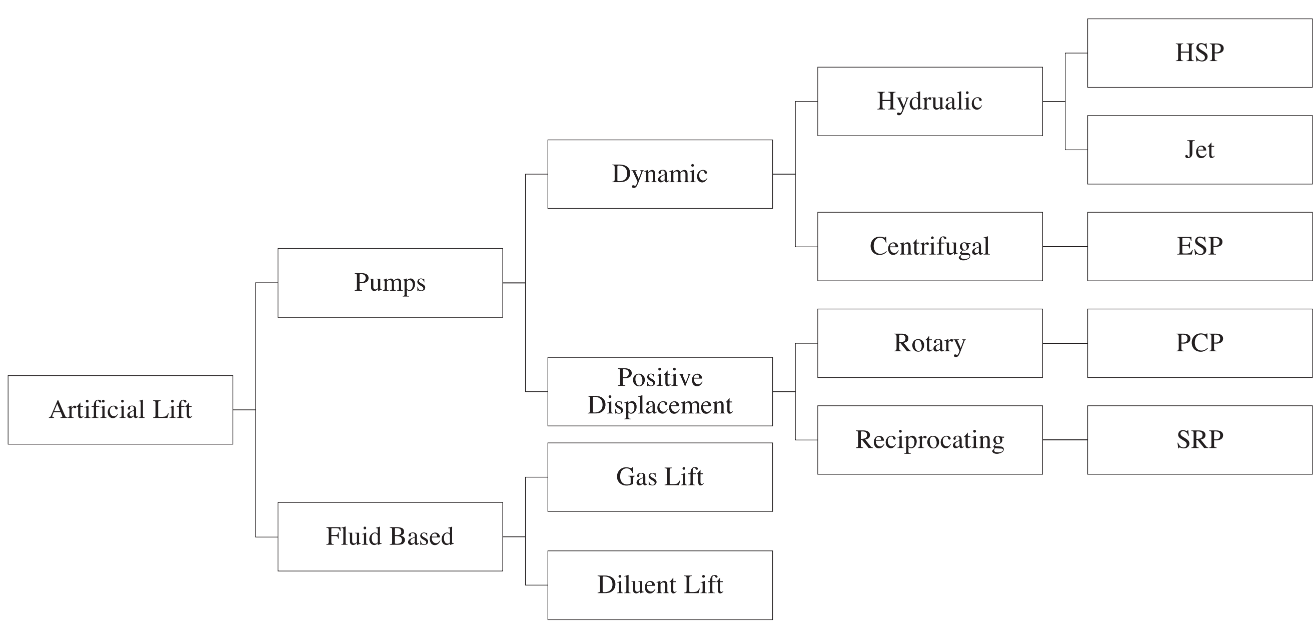


Fig. 4. List and classification of artificial lift methods.

Table 2
Operating ranges and limits of artificial lift methods.

Parameter	Unit	AMPCP	ESP	Jet Pump	HSP	Gas lift	SRP
Minimum depth	ft	2000	1000	5000	2000	5000	100
Maximum depth	ft	7500	16,000	15,000	20,000	15,000	14,000
Minimum capacity	BPD	5	150	300	50	100	50
Maximum capacity	BPD	5000	60,000	35,000	60,000	50,000	7000
Maximum temperature	°F	450	400	500	500	400	500
API gravity	°	< 35	> 10	> 8	> 8	> 15	> 8
Viscosity	cP	–	< 400	< 800	< 800	< 1000	< 500
GOR	$SCF.STB^{-1}$	–	< 2000	< 2000	< 2000	–	< 2000
Sand content	%	–	< 0.01	< 3	< 0.01	–	< 0.1
Wellbore deviation	°	< 80	< 80	–	–	< 70	< 50

The energy efficiency of each artificial lift method inevitably fluctuates due to the long-term varying oil production conditions. However, energy efficiency ranges and expected values can be determined for each method on the basis of a wide body of literature references can be expected from each method. Fig. 5 illustrates the expected energy efficiency ranges and the highest probability (most encountered) industrial value, for each artificial lift method [2,31].

Table 3
Artificial lift methods and operational issues ranking.

Operational Issue	AMPCP	ESP	Jet Pump	HSP	Gas Lift	SRP
Corrosion	1	3	1	2	2	3
Emulsion	1	4	3	3	2	3
Foam	1	2	2	2	1	2
Asphaltenes	1	4	2	3	3	3
Waxes	3	2	2	2	2	3
Solids	1	4	3	3	2	3

A qualitative comparison of artificial lift methods with respect to their capability to handle operational issues entails ranking their performance from 1 to 5, as presented in Table 3 [2,10,16,17,27]: therein, a higher ranking number indicates a higher tendency of the performance to be affected by the associated operational issue.

To check the relative suitability of artificial lift methods with respect to petroleum reservoir conditions as accurately as possible at conceptual level, their operating envelopes and applicability conditions must be evaluated against all corresponding critical parameters simultaneously: an essential part of the present study involved the development of an Excel-based software tool which automates the systematic qualitative and quantitative comparison of IOR methods on the basis of reservoir and well production data availability.

3. IOR methods screening, comparison and selection

The fundamental property which should be considered during the IOR methods screening procedure is the geological formation rock type. Recent statistics (2004) indicate that the overwhelming majority (almost 80%)% of all IOR method implementations concerned sandstone reservoirs [28]. Despite the dominance of thermal methods for IOR from sandstone reservoirs, these methods also account for the lowest share of projects for IOR from carbonate reservoirs, because of the rapid heat loss to overburden and underburden rock layers [38].

Another extremely significant criterion for the selection of IOR methods is the petroleum reservoir depth: in the case of heavy oil production, reservoir depth must also be correlated with viscosity, because the difficulty in ensuring heavy oil flow increases as a function of reservoir depth as well as crude viscosity. For example, thermal methods are capable of handling high crude oil viscosities at low depths, while gas injection methods are the most suitable choice for efficient oil production from deep reservoirs encountered in offshore fields [4,32,41].

With the exception of thermal methods, the applicability of IOR methods for heavy oil production projects has not been hitherto demonstrated. Therefore, in order to simplify the comparison stage, the methods which are a priori deemed unsuitable for heavy oil extraction have been eliminated on the basis of API gravity and viscosity data; furthermore, some of the IOR methods with confirmed capability but limited success in heavy oil production

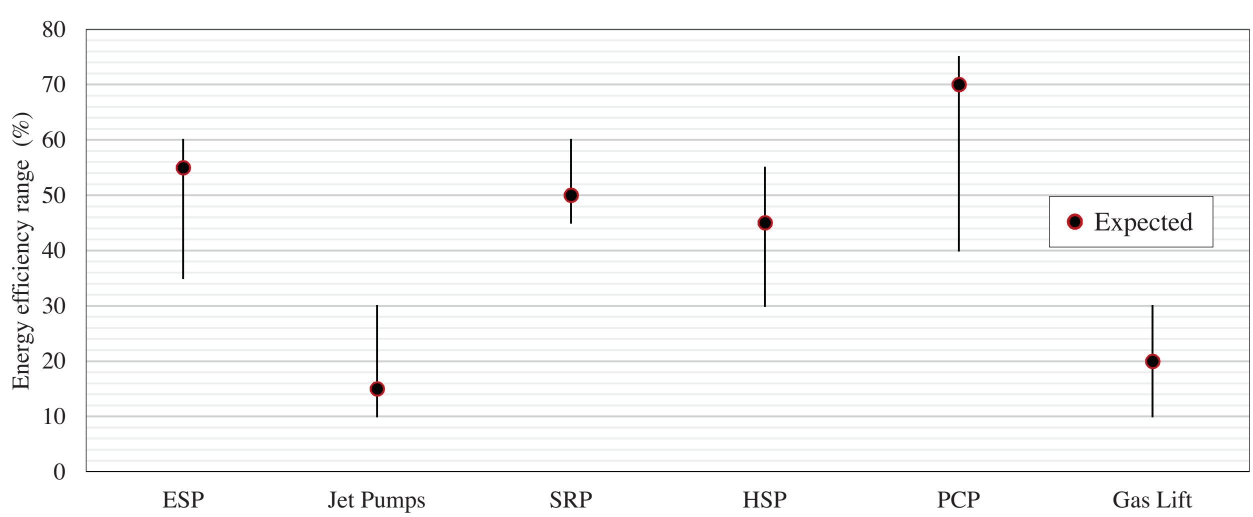


Fig. 5. Energy efficiency range of artificial lift methods.

(according to recent project implementations) have also been dismissed. For example, in-situ combustion has been eliminated due to the fact that after 60 years of development, it has only been commercially applied in USA with high CAPEX and OPEX requirements [24].

Following the pre-screening and elimination stage, the next nine methods have been shortlisted for quantitative comparison:

- Steam-based methods
- Hot Water Flooding (HWF)
- Polymer flooding (Wassmuth et al., [41])
- Alkali-Surfactant-Polymer (ASP)
- Miscible and immiscible hydrocarbon gas injection (M HC and IM HC, respectively)
- Immiscible nitrogen injection (IM N_2)
- Immiscible CO_2 injection (IM CO_2)
- Water Flooding (WF)
- Immiscible hydrocarbon WAG (IM WAG)

Beyond the geological formation rock type, the oil viscosity and the petroleum reservoir depth, other key parameters should also be considered for the purpose of comparing and screening the applicable IOR methods:

- Location of the field
- Natural water drive of the reservoir
- Formation permeability and porosity
- Reservoir thickness
- Reservoir pressure and temperature
- Formation oil saturation

For example, in the case of an offshore field, steam-based methods are eliminated by default, due to the excessive heat loss through subsea pipelines. Table 4 is generated on the basis of a compilation of data from numerous commercial and pilot IOR projects, and can be used as a database in order to compare the boundary limits of each of these IOR methods with respect to several critical parameters [1,5,6,21–23,37,38]. Two important points should be considered when these applicability ranges are used. First of all, these values are based on the maximum and minimum values derived from actual industrial project reports. Secondly, similar to artificial lift boundaries, these numerical values are subject to change as IOR technologies and their performance are continuously modified and improved. Once the technical applicability and viability of IOR methods has been confirmed, the key factor affecting the determination of the optimal IOR method for a given heavy oil production project is the comparative and comprehensive economic evaluation of all candidate IOR methods by means of quantitative (CAPEX, OPEX) criteria.

Oil recovery factors for each IOR method can be estimated on the basis of published literature data reported for the respective oil recovery factors of corresponding IOR project implementations, as illustrated in Fig. 6 [1,8,11,22,23,35,38]. The oil recovery factor has high importance toward the selection of the most suitable IOR method, because the increased revenue derived from the additional oil produced can be the decisive factor offsetting (or not) the additional (CAPEX and OPEX) investment required. Similar to Table 4, caution should be exercised when using the values in Fig. 6, because most of the published literature data refer to oil production projects which have undergone the installation and operation of more than one IOR methods during the oil field production life: accordingly, it is likely that the IOR-induced oil recovery factors reported are not to be solely attributed to the most recently applied IOR method.

Because all applicability requirements of IOR methods should be considered simultaneously toward minimising the error and time requirement for technoeconomic evaluation, an Excel-based

Table 4
Boundary criteria for selection of IOR methods.

Methods	Minimum Permeability	Maximum Permeability	Minimum Porosity	Minimum Depth	Maximum Depth	Reservoir Thickness	Minimum Viscosity	Maximum Viscosity	Reservoir Temperature	Reservoir Pressure	API Gravity	Oil Saturation
	(mD)	(mD)	(%)	(ft)	(ft)	(ft)	(cP)	(cP)	(°F)	(psi)	(°)	(%)
CSS	2000	-	20	1000	3000	>20	300	-	-	<4000	<20	20
SF	100	-	36	500	3000	>10	300	-	-	<4000	<20	20
SAGD	50	-	18	-	5000	>6	50	350,000	-	<4000	-	20
HASD	300	-	20	300	4000	>15	140	20,000	-	<4000	-	20
HWF	900	6000	25	500	3000	-	170	8000	75135	-	>10	15
Polymer	2	9000	10	500	9500	<25	0.1	5000	70240	1452200	>12	30
ASP	500	9000	16	2000	4800	<25	10	6500	80180	1452030	>20	30
IM CO_2	20	1000	15	1200	8500	-	-	600	80200	-	>11	30
M HC	20	5000	4	300	15,900	-	0.1	500	70330	12805000	>20	30
IM HC	20	5000	5	1800	8000	-	-	10	<200	-	>20	75
IM N_2	3	2800	11	1700	18,500	-	-	20	80330	-	>16	45
WF	3	-	15	-	10,000	-	-	2000	-	-	>14	20
IM WAG	100	6600	18	2500	9200	-	-	16,000	80270	-	>6	70

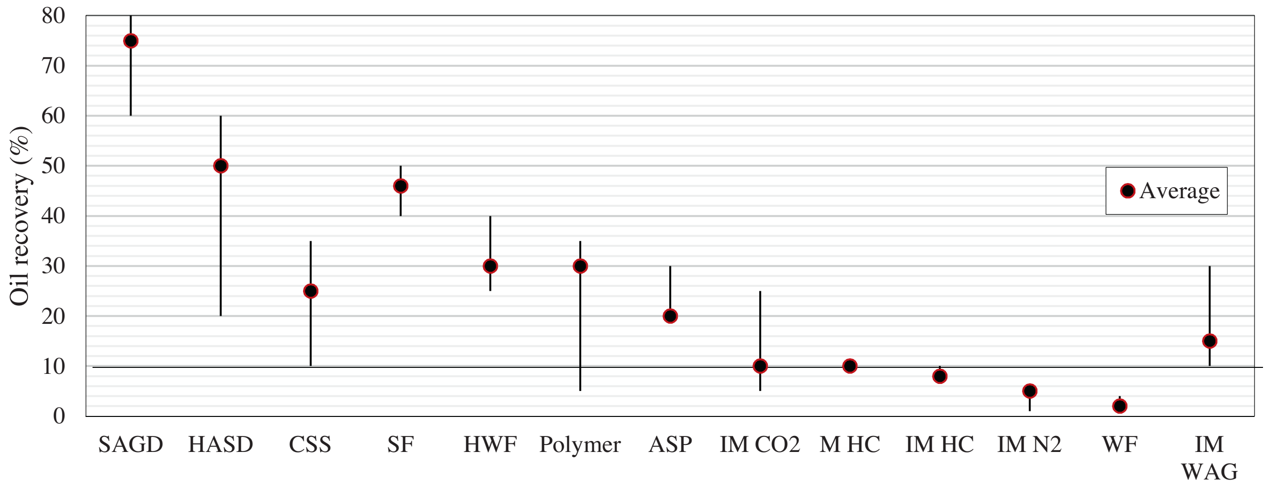


Fig. 6. Recovery factor range of final IOR methods.

screening software tool has been developed: it considers all criteria reported in Table 4, as well as oil field location, geological formation rock type and oil recovery factor of the suitable IOR methods in comparison to the typical topside facility production efficiency.

4. Technoeconomic analysis

Developing a novel methodology for integrating promising IOR methods into petroleum reservoir and well simulation software requires eliminating the unsuitable ones and identifying the subset of applicable IOR methods. Ideally, at least one (i.e., one thermal, one chemical and one cold) method must be selected from each IOR category, according to the foregoing classification (Figs. 2-3). However, since the main objective has been to ensure rapid evaluation and total cost minimisation, only the methods which can be simulated via empirical correlations have been considered; the ones which require sophisticated reservoir simulation (e.g. ECLIPSE) also necessitate a more laborious and costly task of seamless software integration, thereby impeding the effort to accelerate the process of generating a low-cost, uncomplicated workflow methodology for systematic screening and technoeconomic analysis of IOR methods.

First of all, application of cold methods has been considered: to ensure production sustainability, only the methods by which the reservoir pressure is maintained can be evaluated for possible implementation. Therefore, the miscible gas injection method has been deemed unsuitable for heavy oil production, because of the decisively prohibitive complexity and uncertainty of gas dissolution in the reservoir.

Next, thermal IOR methods have been considered. Steam Assisted Gravity Drainage (SAGD) and Horizontal Alternating Steam Drive (HASD) have been eliminated as these methods are not mature enough in order to allow for securing adequate project-based data for reliable heavy oil reservoir modelling. Cyclic Steam Simulation (CSS) has also been eliminated because of the observed inaccuracy of empirical correlations in capturing the steam latent heating effect on the heavy oil reservoir.

Finally, chemical methods have been considered: literature and industrial practice indicate that a reliable quantitative evaluation of their efficiency necessitates frequent reservoir sampling and offline laboratory testing in tandem with multiparametric computational simulation by means of specialised, integrated asset models. Because of the significant additional OPEX and the considerable uncertainty introduced in quantitative analysis, further consideration of chemical methods at this level has been deemed impractical.

The applicable IOR methods, therefore, have been shortlisted as follows:

- Thermal flooding methods; i.e., steam and hot water flooding
- Pressure maintenance methods; i.e., water flooding and immiscible gas injection

Both foregoing classes encompass flooding-based methods, whose computational simulation requires injection and production well modelling in addition to reservoir modelling: both are of great importance and must hence be integrated into the technoeconomic analysis tool used towards selection of the most suitable IOR method.

The scope and potential for application of IOR methods is sensitive to the quantitative projection of additional oil extracted, it hence it has been decided to base the methodology for their systematic evaluation on the maximum possible oil flowrate which is projected as achievable through the production well. Selecting the maximum attainable oil flowrate based on the reservoir conditions at the production well bottomhole point enables the most reliable estimation of the capital and the operating cost of each (a priori deemed applicable) IOR method. Consequently, the profitability of different IOR methods can be systematically examined on a unified performance basis. The four methodological steps towards achieving this key objective are the following:

1. Computation of the production profile and selection of the maximum (as well as the target) liquid flowrate from the production well
2. Calculation of the required injected fluid for obtaining the target production rate
3. Determination of the operating conditions of injection facilities
4. Economic evaluation of each method on the basis of market conditions (oil price, interest rates) and quantitative (OPEX, CAPEX, NPV) investment criteria

To implement the foregoing methodological steps, several software components are necessary; their interoperability must also be ensured within an integrated asset modelling (IAM) tool. RAVE (Risk & Value Engineering) is the in-house IAM tool of Ingen-Ideas Ltd. which provides the capability to combine reservoir, injection well and production well modelling with explicit consideration of heavy oil production process economics, in an integrated scenario-based software environment.

Furthermore, RAVE can estimate the cumulative oil production rate during the entire oil production project lifecycle, by means

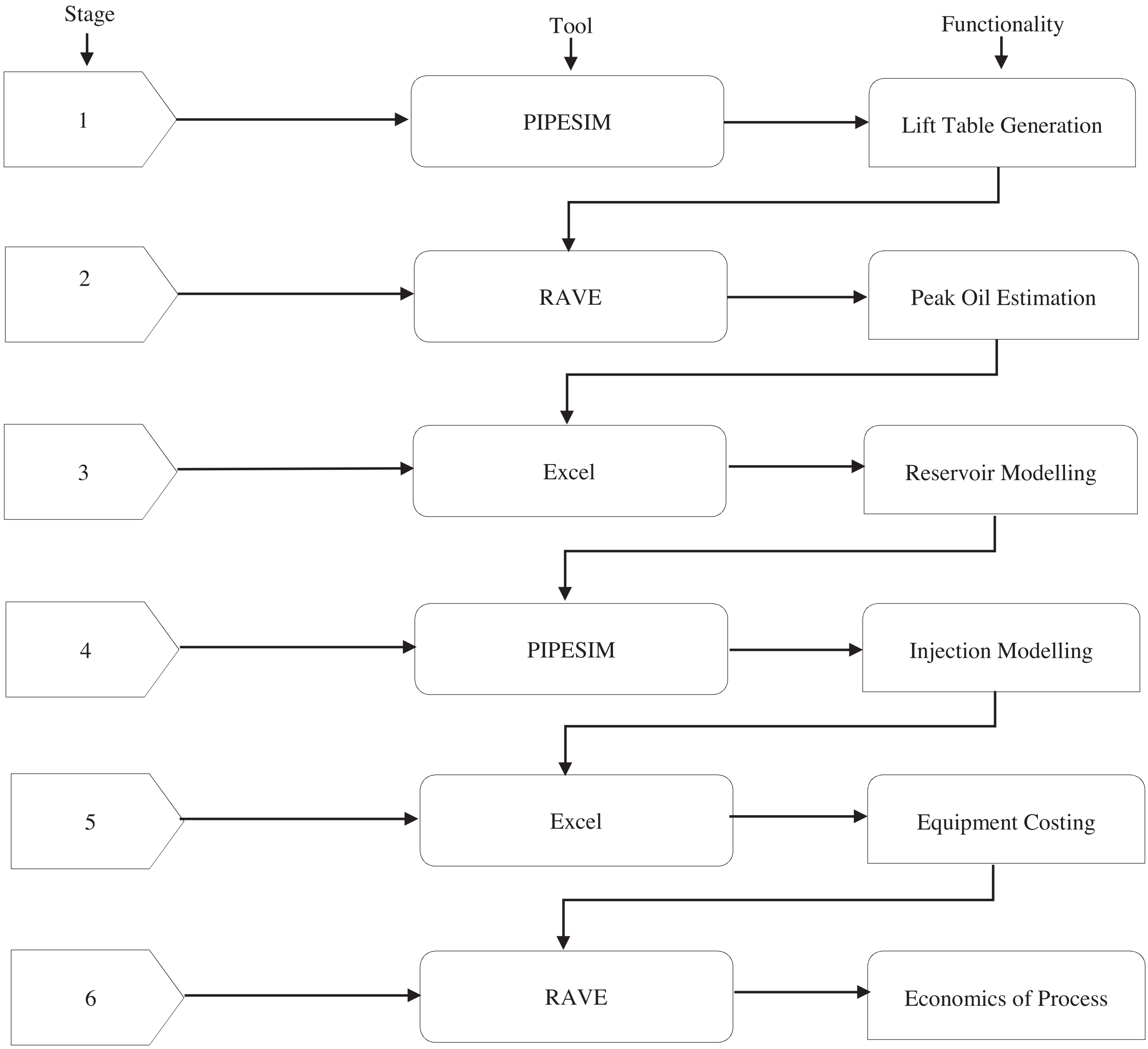


Fig. 7. Software employed and execution sequence followed in the proposed database and workflow integration methodology.

of employing production system (well and flow line) pressure drop profiles (lift tables) which can in turn be computed using Schlumberger's commercially available production simulation software (PIPESIM).

Finally, Microsoft Excel can be used to post-process reservoir behaviour model results and perform the detailed project cost estimation. To summarise, in total, three separate software applications have been employed for systematic process modelling and technoeconomic evaluation of the selected IOR methods:

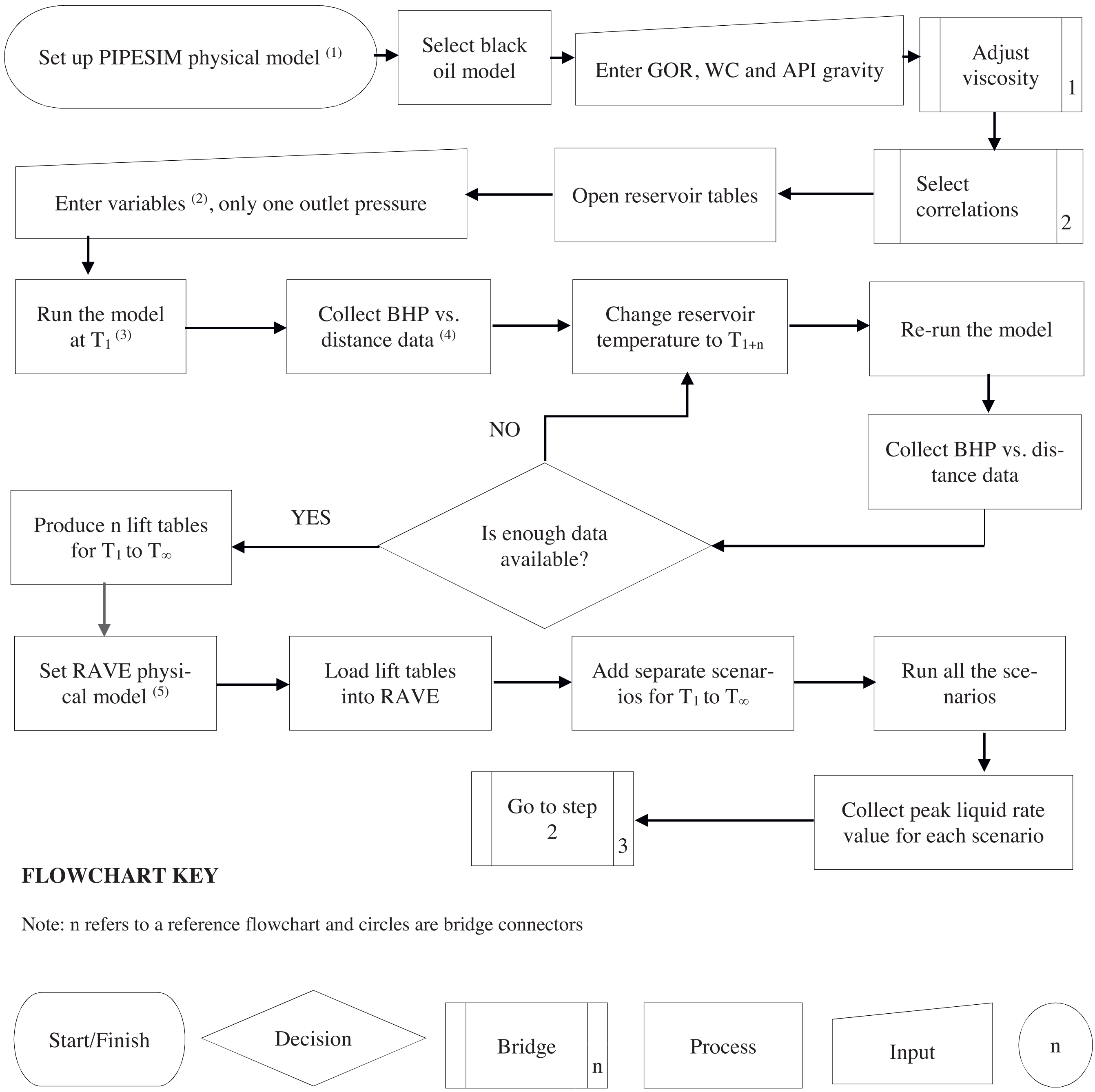
- Ingen RAVE (to generate field production lifecycle expectations and perform production project NPV estimation)
- Schlumberger PIPESIM (to generate well and pipeline pressure drop profiles and reference tables)
- Microsoft Excel (to perform reservoir and production system model result post-processing and compute CAPEX and OPEX estimates)

Fig. 7 summarises the order in which each tool is used alongside the functionality of it in the respective stage (data transfer between software applications is carried out manually).

4.1. Thermal flooding methods - Step 1: Production system hydraulic modelling

The first step towards simulation of IOR method performance is the calculation of the crude heavy oil production profile. The novel methodology followed is presented with detailed flowcharts: Fig. 8 illustrates the procedure for obtaining the heavy oil thermal flooding pressure drop profiles (lift tables); Figs. 9-11 depict the procedure for obtaining the maximum oil flowrate through PIPESIM and RAVE.

The Hossain correlation which is given by Eqs. (1-3) is solely applicable to heavy oil and can be used in case of lack of experimental oil viscosity data: it provides reasonably accurate results for heavy oil API gravity between 10 and 22° [15].



ALGORITHM SPECIFICATIONS

(1) Includes the reservoir, tubing, flowline (variable number), risers and nodes in PIPESIM
(2) Includes the simulation variables such as water cut, gas to oil ratio, liquid flowrate and system outlet pressure
(3) T_1 refers to the reservoir initial temperature. This should be added to the reservoir parameter of the PIPESIM physical model
(4) Since each tubing, flowline and riser requires a lift table, the distance is dependent on the length of each respective parameter
(5) This includes the reservoir, flowline, tubing, riser and host facility. In addition, the economical parameter might be added to the system in cases where economic analysis of the system is required

Fig. 8. Procedural flowchart for step 1.

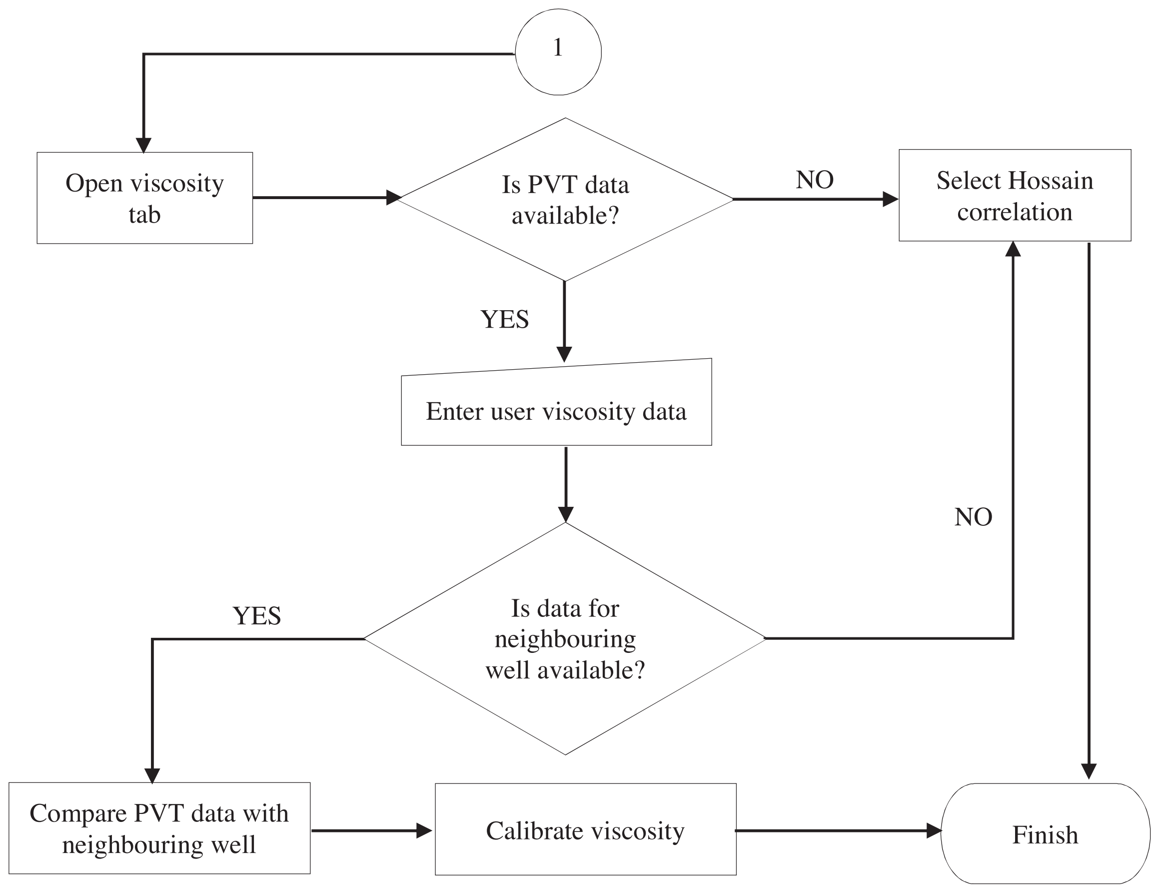


Fig. 9. Viscosity model modification for heavy oil in PIPESIM.

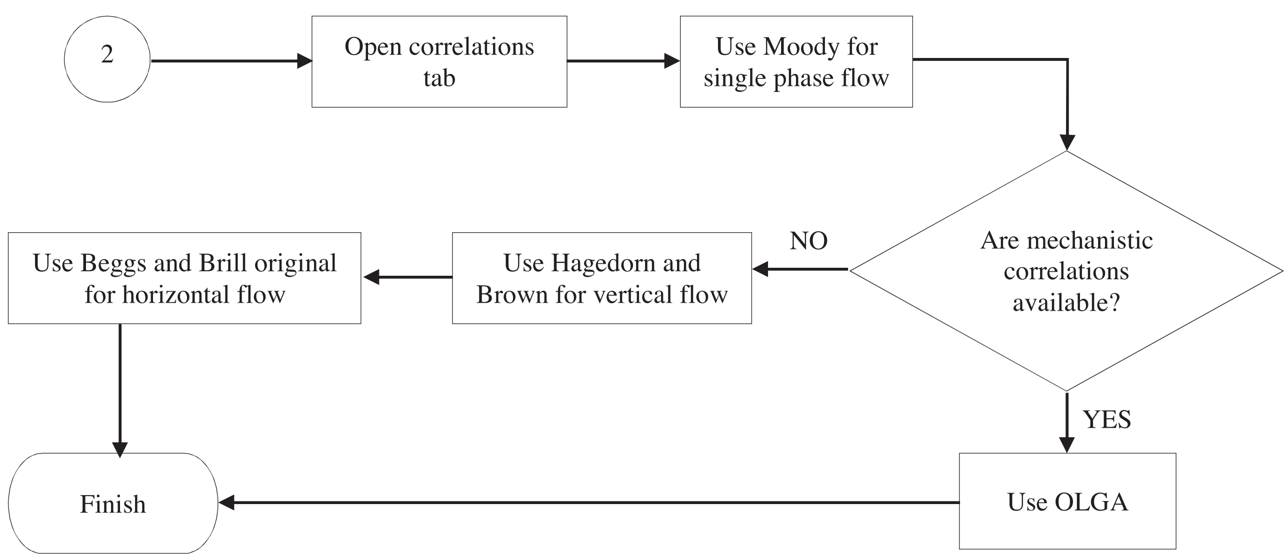


Fig. 10. Correlation assignment for heavy oil pressure drop calculation in PIPESIM.

$$\mu_{od} = 10^{A}.T^{B} \tag{1}$$

$$A = -0.71523.API + 22.13766 \tag{2}$$

$$B = 0.269024.API - 8.268047 \tag{3}$$

Conversely, Eqs. (4-6) must be used in order to calibrate the PIPESIM viscosity correlations when experimental oil viscosity data are available for the specific heavy oil field.

$$\log(\mu) = \log(B) - C\log(T) \tag{4}$$

$$C = \frac{\log\left(\frac{\mu_1}{\mu_2}\right)}{\log\left(\frac{T_2}{T_1}\right)} \tag{5}$$

$$\mathrm{B} = \mu_1 \mathrm{T}_1^{\mathrm{C}} = \mu_2 \mathrm{T}_2^{\mathrm{C}} \tag{6}$$

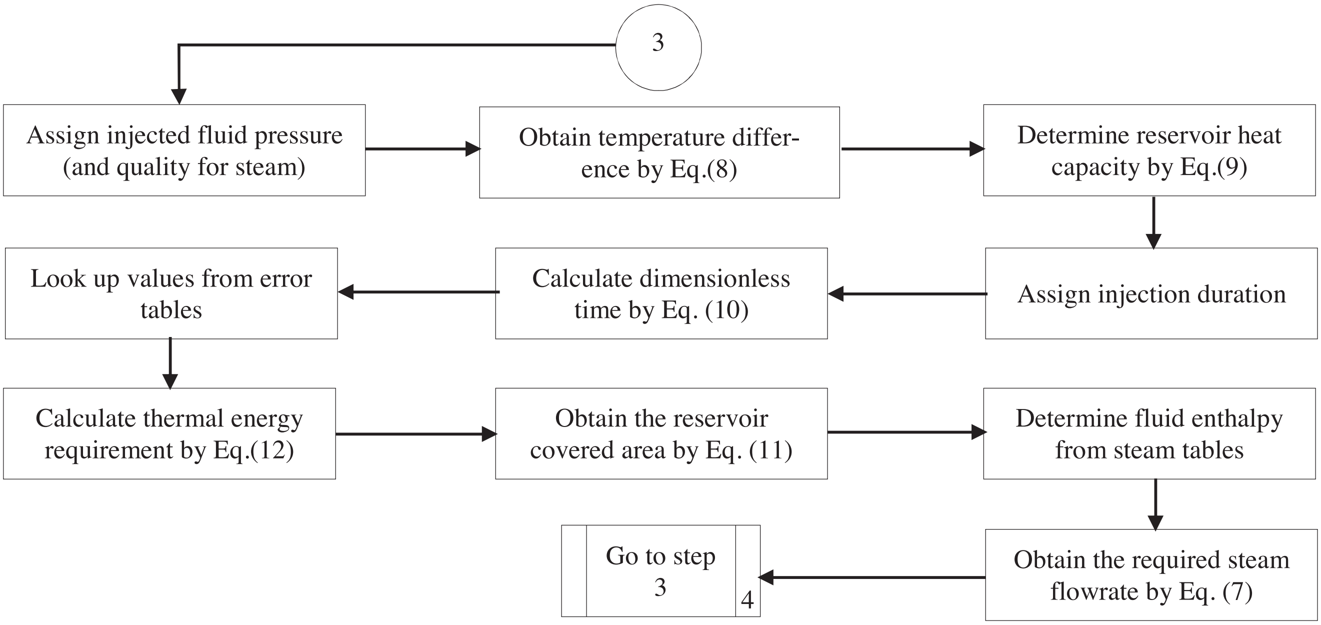


Fig. 11. Procedural flowchart for step 2.

Heavy oil viscosity estimation data is thus organised and saved as tables (Microsoft Excel files) which are then imported into RAVE.

4.2. Thermal flooding methods - Step 2: Reservoir shortcut modelling

The pressure drop profiles and data tables computed via PIPESIM must be interfaced with RAVE, in order to determine the target heavy oil production flowrate which should be achieved as well as the required injected fluid flowrate which is to be employed in order to facilitate heavy oil production. Reservoir and heat loss modelling and analysis are thus required, and the cumbersome effort implied by explicit reservoir simulation can be circumvented by the use of several empirical correlations developed for heat loss calculation, which allow for computational efficiency and reasonably high accuracy. Four of the most established thermal flooding models of widespread use are the following:

- The Marx and Langenheim (M&L) model
- The Mandl and Volek (M&V) model
- The Myhill and Stegemeier (M&S) model
- The Jones model

The M&L model has historically been the base for the development of reservoir simulators, while both M&V and M&S models represent subsequent improvements which have sought to improve upon the accuracy of the M&L model, which has high reliability and a proven record of performance based on previous thermal flooding projects [36,38]; accordingly, it has been selected for simulation of thermal flooding methods in this paper, with the inclusion of critical M&V as well as Ramsey modifications.

Proposed in 1959, the Marx and Langenheim (M&L) model balances the heat injected into the reservoir, the heat loss in the formation and the heat loss to the reservoir rock formations, excluding the heat loss to the cold oil zone in front of steam, employing the following assumptions [18,29,35,38,40]:

- Constant fluid injection rate
- Fixed injected fluid conditions (pressure, temperature and steam quality)
- Uniform vertical temperature distribution in the reservoir
- No separation between steam and condensate by gravitational affects
- Constant petroleum reservoir properties
- Ideal step function between hot and cold zones in the reservoir
- Instant thermal equilibrium in the reservoir

The first step towards an M&L reservoir simulation entails defining the injected fluid conditions and flowrate. The constant heating rate due to the injected fluid is obtained as:

$$Q = h_{hf}.M_{hf} \tag{7}$$

Based on the step function assumption, the temperature difference between the injected fluid and the petroleum reservoir is constant and calculated as:

$$\Delta T = T_{hf} - T_r \tag{8}$$

The constant heat capacity of the overburden and underburden rocks is obtained as:

$$C = (1-\phi)\rho_r c_r + S_w \phi \rho_w c_w + S_o \phi \rho_o c_o \tag{9}$$

To obtain the area covered and the heavy oil volume produced, the time which has elapsed since the initiation of production should be considered. Marx and Langenheim introduced a dimensionless time function in order to consider this significant factor:

$$x = \frac{2k\sqrt{t}}{CH\sqrt{D}} \tag{10}$$

The area of reservoir swept during time t is thereby computed as:

$$A(t) = \left[\frac{QCHD}{4k^2\Delta T}\right]\left(e^{x^2} erfc(x) + \frac{2x}{\sqrt{\pi}} - 1\right) \tag{11}$$

Consequently, the volume of oil displaced after t hours of production is calculated as:

$$V_o = 4.237\left[\frac{Q\phi(S_o - S_{or})}{C\Delta T}\right]\left(e^{x^2} erfc(x)\right) \tag{12}$$

The numerical values of error functions embedded in Eqs. (11) and (12) can be found in [29]. Finally, the heat loss percentage to the reservoir rock during the injection period can be calculated by using Eqs. (13) and (14):

$$x^2 = \frac{4Dt}{H^2} \tag{13}$$

$$Q_L = 1 - \frac{1}{x^2}\left(e^{x^2} erfc(x) + \frac{2x}{\pi} - 1\right) \tag{14}$$

Because the M&L model only considers the heat loss mechanism in the reservoir without incorporating injection and production wells, it cannot be used for steam flooding simulations: the resulting M&L model inaccuracy in production well oil flowrate predictions [29,36] is addressed by implementing a back-calculation methodology, through which the maximum production flowrate is estimated more accurately via PIPESIM on the basis of the production well bottomhole pressure. Fig. 11 presents a summary of the procedure to obtain the injection flowrate from the maximum production flowrate computed in step 1.

4.3. Thermal flooding methods - Step 3: Injection well and topside requirements

The steam rate calculated in step 2 is based on the steam conditions required at the bottomhole of the injection well. However, the design of topside facilities must consider steam properties and requirements prior to injection, which necessitates computing the pressure drop and heat loss along the well and tubing during the injection via PIPESIM. Fig. 12 illustrates the slightly different procedures followed in step 3 for the two distinct cases of steam flooding and hot water flooding.

4.4. Thermal flooding methods - Step 4: Economic evaluation

The costing of thermal flooding methods is performed in the same fashion as for conventional oil extraction methods, employing some additional parameters required for heating processes. A simple costing procedure which is sufficient for preliminary quantitative screening and comparison of the methods has been followed for the purpose of this paper: in case of only small differences in the criteria considered, a more detailed technoeconomic evaluation (e.g. using itemised quotes) may be essential in order to reach firm conclusions.

The first step towards the economic analysis of thermal flooding methods is the evaluation of capital and operating cost (the latter is constant due to the assumption of a fixed injection rate). The most important parameters for the calculation of thermal flooding OPEX are the following:

- Boiler or heater feed water requirement
- Water pumps electric energy requirement
- Water treatment processes
- Boiler/heater fuel consumption
- Transportation

These costs must ideally be specified by the project owners based on vendor quotes or technical know-how and experience from previous completed projects, due to the high degree of variety and sophistication featured by the corresponding implemented technologies. However, if these essential economic data are not available, some of the parameters necessary for continuous injection, (e.g. cost of fuel, electricity and water) can be estimated. These estimations can be carried out based on the amount of thermal energy (and consequently mass of steam or water) required. The capital cost (CAPEX) should be estimated after calculating the operating cost (OPEX) of the project: for this, the main parameters required for thermal flooding methods are the cost of:

- Injection and production well drilling
- Boiler or heater
- Pumps
- Fuel and water storage facilities
- Water treatment facilities

Well drilling cost is a variable based on the field location and rock properties, hence an accurate estimation is only possible after evaluating the field properties. However, the well drilling cost can be estimated as a function of depth.

Costing of boilers and pumps must consider the technology used and the location of the field. Preliminary cost estimations are possible using the costing correlation and factors given in [39]. The capital cost of pumps and boilers can be estimated based on volumetric and mass flowrate of injected fluid, respectively, via the next general correlation:

$$CX_m = a + bZ^n \tag{15}$$

The values for a and b (constants) for each equipment type can also be found in [39]. If storage facilities are not already available at the field, their cost can also be obtained with this method.

The next step is to compute the financial potential of the thermal flooding IOR methods on the basis of product (heavy oil) sales: the Net Present Value (NPV) of the project should be calculated using the production profile obtained from RAVE via the definition:

$$NPV = \sum_{n=0}^{N} \frac{CF_n}{(1+r)^n} \tag{16}$$

The cash flow used in NPV calculation is computed by RAVE and is the positive difference between the generated income and the projected total expenditure of the heavy oil production project.

4.5. Pressure maintenance methods

The procedure applied for pressure maintenance IOR methods simulation and technoeconomic analysis is similar to that followed for thermal flooding IOR methods, with the sole exception of step 2. The main differences between the two methods are the following:

- Step 1: No need for multiple runs at different bottomhole temperatures
- Step 2: The reservoir is assumed to be a tank with fixed volume. Therefore, in order to produce the amount of oil considered in step 1, the same amount of fluid should be injected into the reservoir: a simple mass balance thus replaces the reservoir shortcut modelling procedure explained in the thermal flooding section
- Step 3: The procedure is similar to the hot water flooding procedure illustrated in Fig. 12, with a possibility of different injection fluids
- Step 4: The procedure is similar without the need for heating equipment but with a possibility of different compression equipment in case of gas injection processes

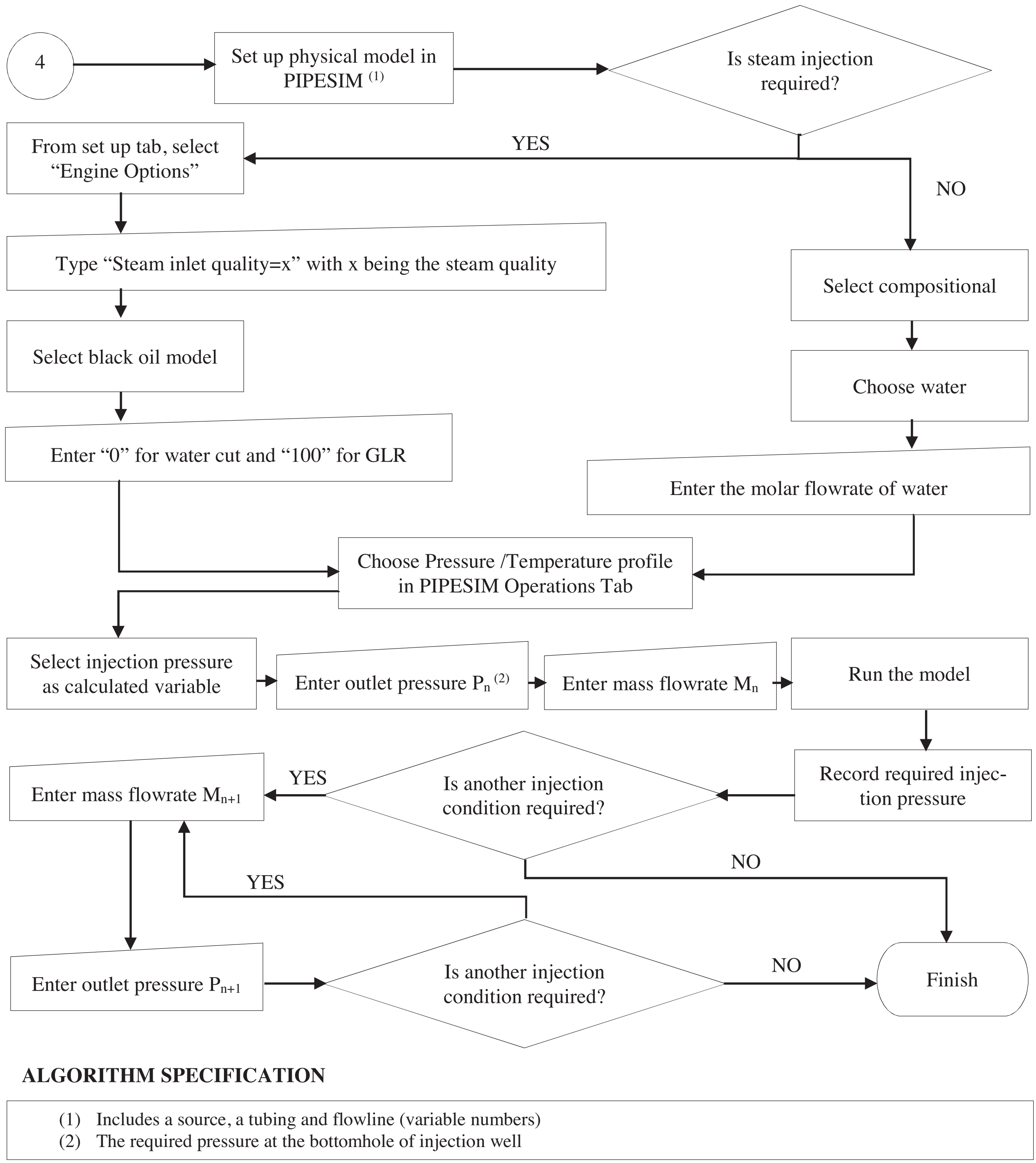


Fig. 12. Procedural flowchart for step 3.

5. Case study

To investigate the practicality and efficiency of the proposed methodology, a case study has been considered based on realistic problem data from an onshore heavy oil field. The effects of water cut profile, reservoir pressure, injection temperature and fuel type on economics and operability of the IOR methods have been examined. The methods considered in the case study are the following:

- Natural flow (base case)
- Steam flooding
- Hot water flooding
- Water flooding
- CO_2 injection (immiscible)

Natural flow has been considered as the base case in order to measure the impact of IOR methods against it. Carbon dioxide (CO_2) injection has been chosen because of the ever-increasing scientific as well as industrial interest in Carbon Capture and Storage (CCS) technologies. Furthermore, water flooding, hot water flood-

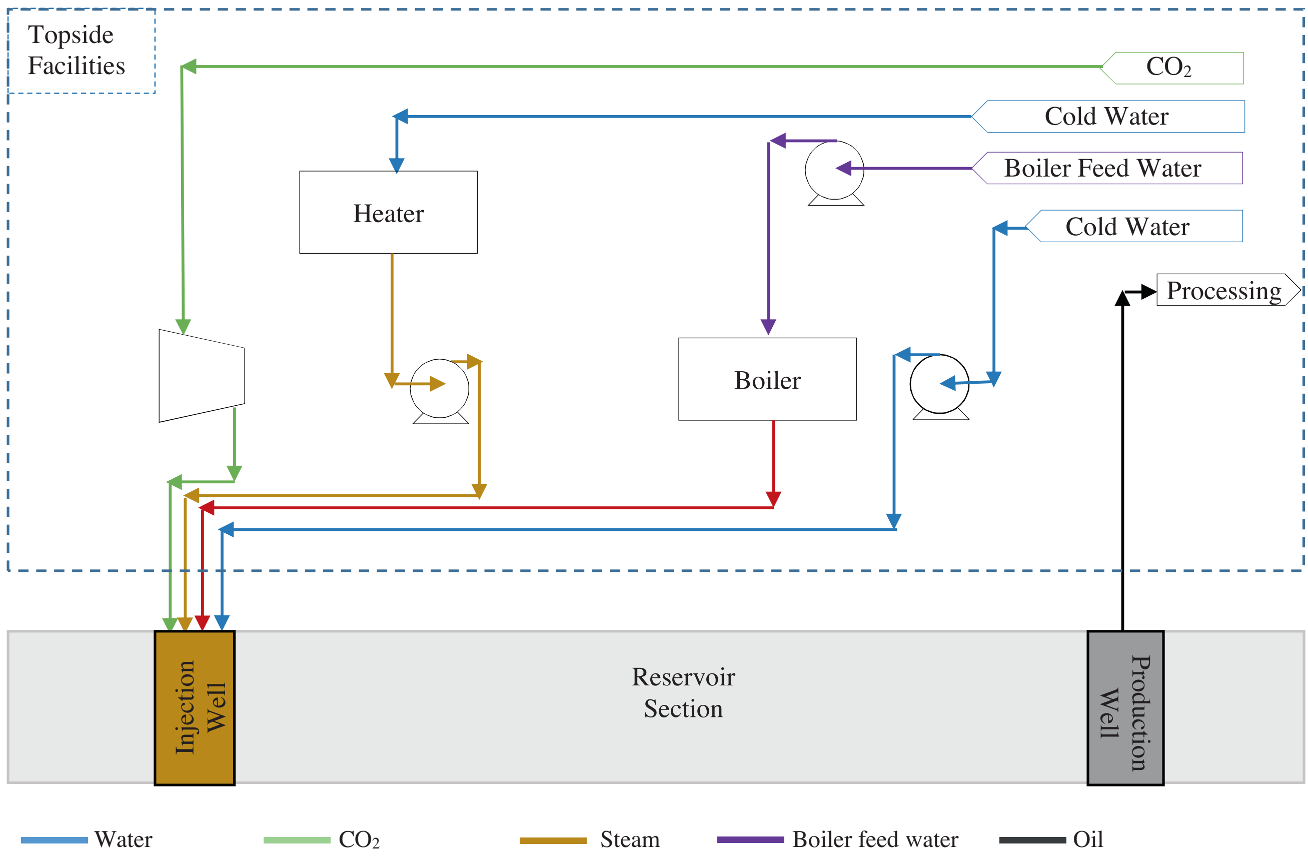


Fig. 13. Comparative illustration of selected IOR methods for use in the case study (processes cannot be operated simultaneously).

ing and steam flooding have been selected in order to highlight the impact of stepwise heat addition on heavy oil production and process economics.

Fig. 13 shows a simple schematic of the topside facilities required for each IOR method. In all cases, it is assumed that injected fluid is available at the site and the only equipment units required are those used to adjust pressure or temperature. Moreover, since steam injection is considered, it has been assumed that this is an onshore field. The arrangements of pumps and heat exchangers for hot water flooding and steam flooding differ, because water pressure must be increased to boiler operating pressure prior to heating in the case of steam flooding, in order to eliminate the need for compression.

5.1. Oil properties and PIPESIM input data

Both injection and production systems considered in PIPESIM consist of one vertical well and one horizontal flowline (Fig. 14).

Table 5
Case study input data for setting up the production well in PIPESIM.

Property	Unit	Value
Productivity index	STB.psi^{-1}	5
Tubing U value	BTU.ft^{-2}.h^{-1}	2
Tubing depth	ft	1500
Tubing bottom ID	inch	4.87
Tubing casing ID	inch	8.681
Ambient temperature	°C	5
Flowline length	ft	1000
Flowline inner diameter	inch	6
GOR (black oil model input)	SCF.STB^{-1}	40
Water cut (black oil model input)	%	50

Tables 5 and 6 present the properties of the production and injection wells, respectively: as the objective of this case study is the technoeconomic comparison of different IOR methods, these parameters have all been kept constant for all respective scenarios considered.

The reservoir conditions and oil properties (Table 7) have been compared with the boundary data presented in Table 4: results indicate that all four methods considered in this case study (as well as polymer flooding, [41]) are potentially applicable to this specific heavy oil field.

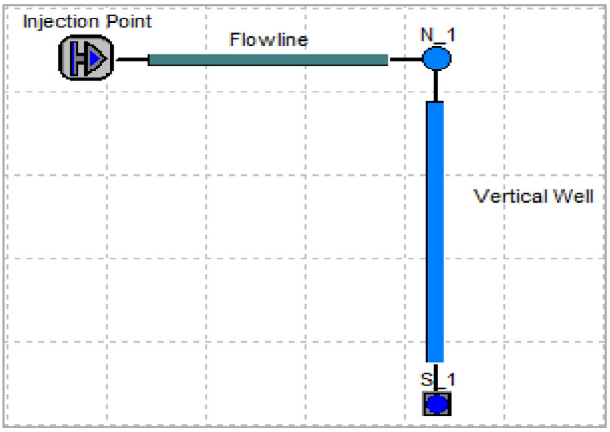
The variable ranges required for generation of lift tables in PIPESIM and use in RAVE are presented in Table 8 (the required topside pressure has been set equal to 300 psi).

5.2. Lift tables

To facilitate importing and post-processing the PIPESIM heavy oil production (reservoir, well set and flow lines) system simulation results into the RAVE IOR technoeconomic evaluation model, lift tables have been generated for the flowline and tubing sections

Table 6
Case study input data for setting up the injection well in PIPESIM.

Property	Unit	Value
Tubing U value	BTU.ft^{-2}.h^{-1}	0.2
Tubing depth	ft	1500
Tubing bottom ID	inch	3.958
Tubing casing ID	inch	8.681
Flowline length	ft	10
Flowline inner diameter	inch	12
Rate of undulation	–	10/1000



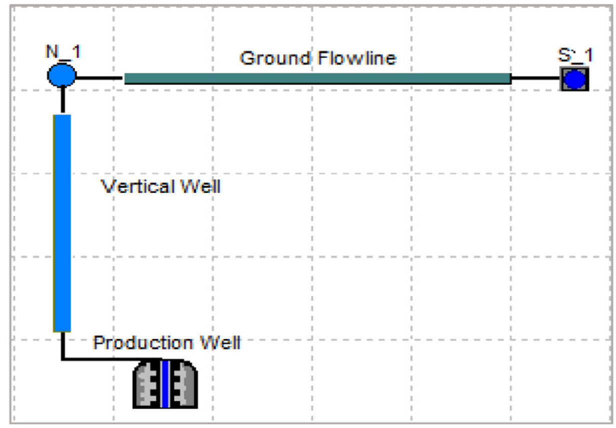


Fig. 14. Schematic of injection (left) and production (right) system in PIPESIM.

of the production well. In total, five pairs of lift tables for five different reservoir bottomhole temperatures have been produced. For the cases of natural flow and pressure maintenance methods, lift tables have been produced at bottomhole temperature of 20 °C (no added heat); moreover, lift tables have been generated for the bottomhole temperatures of 50, 80, 110 and 140 °C which have been considered for thermal flooding methods. Subsequently, an ensemble of 194 graphs have been plotted in order to analyse the effect of Gas to Oil Ratio (GOR), water cut, fluid flowrate and temperature on the pressure drop along the heavy oil production system. The effect of flowrate on pressure drop concurs with the Bernoulli equation, as the pressure drop increases monotonically as a function of heavy oil fluid flowrate.

The effect of GOR variation on pressure drop observes an inverse proportionality relationship: this is expected due to the fact that oil density is reduced as the gas content of the crude oil stream increases. Consequently, the lighter fluid will result in lower frictional pressure losses.

The heat transfer effect on pressure loss has been investigated, indicating that the impact of temperature on pressure drop is insignificant when the water cut exceeds 50%,% in agreement with the prescribed water cut turning point which has been assumed equal to 50% in the PIPESIM production well model (Table 5).

One of the most significant trends observed by inspection of the lift tables has been the decreasing effect of gradual heating (temperature rise) on the pressure drop magnitude: the latter is reduced by 26.2% in the first temperature interval, but only by 1.6% in the last one. This observation has prompted the modification of temperature intervals considered: accordingly, a new set of lift tables has been generated for the revised bottomhole temperatures of 30, 40, 50, 70 and 90 °C. The new temperature intervals yield a more uniform distribution of pressure drop levels, which in turn result in higher clarity of observation and easier evaluation of the impact of IOR thermal flooding temperature on pressure drop and consequently on reservoir fluid flowrate.

Table 7
Properties of the heavy oil field considered in the case study.

Property	Unit	Value
Reservoir temperature	°C	20
Oil API gravity	°	12
Formation thickness	ft	30
Reservoir average porosity	–	0.25
Initial water saturation	–	0.2
Oil saturation	–	0.7
Specific heat of rock	$BTU.lb^{-1}.°F^{-1}$	0.21
Specific heat of oil	$BTU.lb^{-1}.°F^{-1}$	0.5
Rock grain density	lb/ft^3	167
Thermal conductivity rocks	$BTU.h^{-1}.ft^{-1}.°F^{-1}$	1.5
Thermal diffusivity of rocks	$ft^3.h^{-1}$	0.0482
Residual oil saturation	–	0.1
Specific heat of water	$BTU.lb^{-1}.°F^{-1}$	1
Water density	$lb.ft^{-3}$	62.32

5.3. RAVE and M&L model implementation

To configure efficiently the physical RAVE model of the heavy oil production system, a justtified simplification has been necessary: because the heat loss calculations are performed outside RAVE, the injection well has been eliminated from the physical RAVE model and the respective CAPEX and OPEX of the injection well have been added to the production well cost terms. Fig. 15 shows the final arrangement of the RAVE model used in the case study.

Because there has been no petroleum reservoir pressure data available for this case study, it is essential to assign the reservoir pressure in order to execute the RAVE model for technoeconomic evaluation: since there are three different classes of IOR production methods considered in this case study, a decision has been made to assign three different reservoir pressure profiles. In order to facilitate the natural flow of heavy oil, after considering the pressure drops in lift tables, an estimate of 1500 psi has been selected as the initial reservoir pressure. RAVE simulations at reservoir pressures of 1000, 2000, 3500 and 5000 psi have also been carried out for steam flooding and have validated the reliability of this assumption. In the case of natural flow, a constant monthly pressure drop of 10 psi has been considered sufficient. Conversely, a constant reservoir pressure has been assumed for water flooding, hot water flooding and CO_2 injection. Despite the fact that steam flooding can increase or at least sustain the reservoir pressure at the initial pressure conditions in some projects [38], a slight and gradual pressure drop is also likely to occur due to steam condensation [42]. Therefore, a constant monthly pressure drop of 3 psi in the reservoir has been assumed for the case of steam flooding.

Table 8
PIPESIM temperature/pressure profile input.

Liquid Rate ($STB.d^{-1}$)	WC (%)	GOR ($SCF.STB^{-1}$)
10	0	1
100	20	40
1000	50	80
10,000	80	120
20,000	99	160

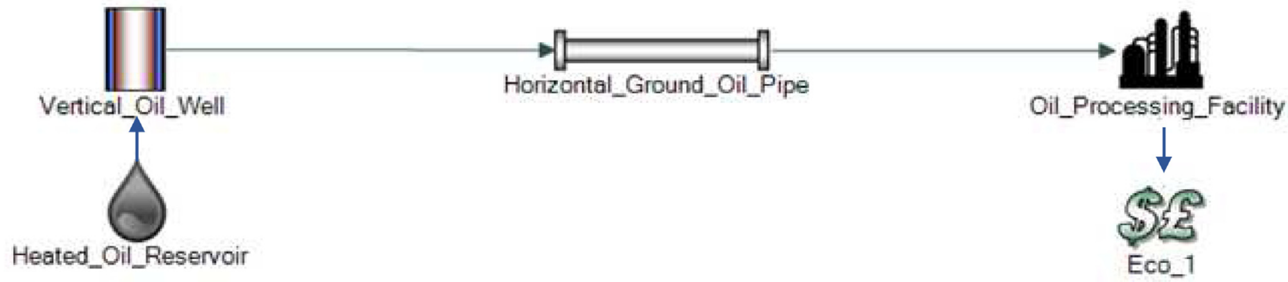


Fig. 15. RAVE physical arrangement used in the case study.

The next step towards running the RAVE model has been to assign a cumulative liquid flowrate profile. This objective has been achieved through a trial-and-error procedure: after obtaining the maximum cumulative flowrate, which coincides with the highest temperature case, the heavy oil production project lifecycle (30 years) has been divided into equal time intervals from project initiation to termination.

In order to include all possible scenarios with respect to the possible variation of water cut, the quantitative analysis approach selected has been to evaluate the project based on three different well water cut profiles denoted as downside (late), medium and upside (aggressive), in order to ensure that the worst-case scenario of early water breakthrough and best-case scenario of late water breakthrough can be reliably compared. Fig. 16 illustrated these three water cut profiles.

Beyond providing the reservoir and well profiles, RAVE requires the specification of boundaries and limits. Accordingly, it has been assumed that the liquid and gas capacity of the topside facilities are limited to 10,000 barrels per day and 10^9 SCF per day, respectively. Furthermore, it has been assumed that all methods will incur the same abandonment cost (5 million GBP): this assumption has been made in order to guard against the potential compilation of gross inaccuracies which may arise in any detailed cost estimation attempt with inadequate data fidelity for the specific heavy oil project.

Further to configuring the RAVE physical model and entering the parameter values considered for the base case (at a production well bottomhole temperature of 20 °C), other scenarios at different bottomhole temperatures, water cut profiles and flooding methods have also been added for detailed consideration. This procedure has resulted in a total of 36 scenarios, for which maximum oil production rates have been obtained by means of RAVE physical model execution: Figs. 17 and 18 illustrate the peak oil flowrates and maximum achievable cumulative oil flowrates (late water cut scenarios) for each IOR method and for each temperature (in case of variation) considered.

The computational model results presented in Fig. 17 indicate that the largest increase in daily oil production rate occurs between 20 and 30 °C. Conversely, even by doubling the interval size at higher temperatures, the production is only slightly increased between 70 and 90 °C.

Despite operating at the same production well bottomhole temperature, hot water flooding achieves spectacularly higher production for all temperatures considered (Fig. 18). This phenomenon can be justified by the constant reservoir pressure assumption for hot water flooding, and the decreasing reservoir pressure drop of steam flooding. The gas (CO_2) and water injection requirements have been computed by performing a mass balance for the process, while the steam and hot water injection requirements have been computed using the M&L model.

To complete the technoeconomic evaluation for the case study and conclusively compare the suitability of different advanced oil recovery technologies, it is essential to calculate the implementation cost for each IOR method. The cost of thermal methods depends on pumping and heating costs, as shown in Fig. 13: because the type of fuel used for heating is an important factor which affects the operating cost (OPEX) of heat-assisted IOR methods significantly, it has been deemed necessary to evaluate all thermal methods considered here with respect to three different types of fuel; natural gas, diesel and crude (heavy oil), yielding a total of 81 scenarios. Figs. 19 and 20 illustrate the CAPEX and OPEX which have been computed for all instances of the considered IOR methods, respectively. Due to the assumption that no extra (hydraulic or heating) assistance is required in the case of natural flow, the OPEX of this IOR method is set to zero and the CAPEX is equal to the sum of the costs for production and injection well drilling.

Fig. 19 indicates that the highest capital investment (CAPEX) corresponds to CO_2 injection, while the lowest one is obtained for

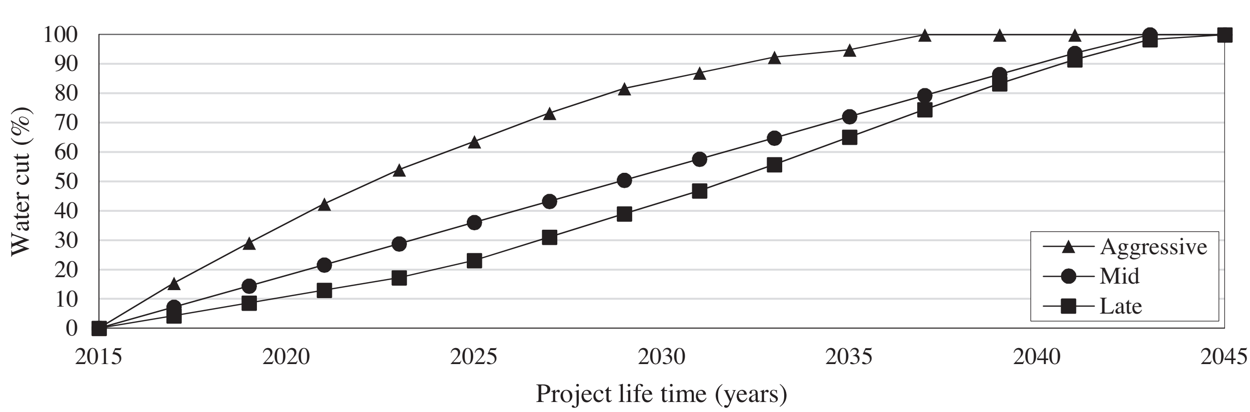


Fig. 16. Production well water cut profiles.

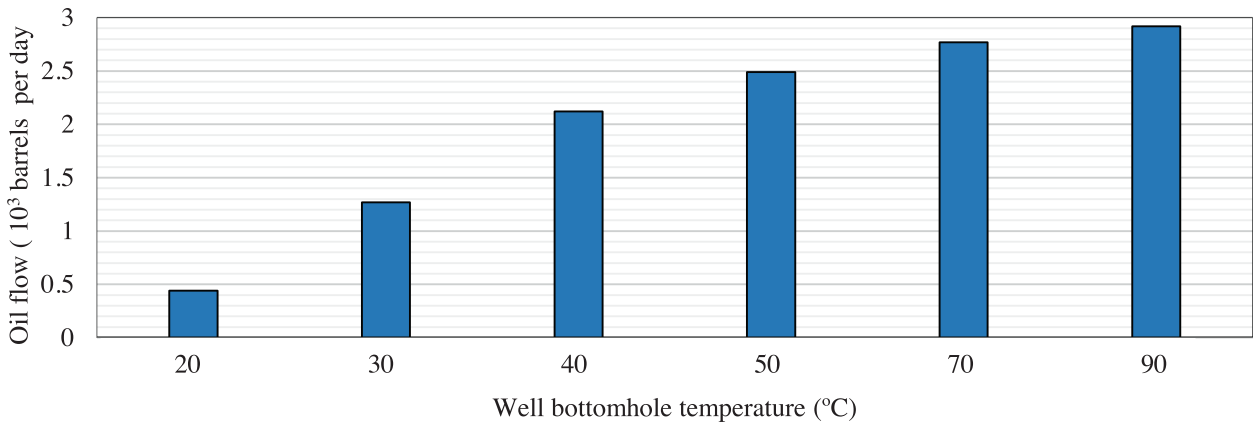


Fig. 17. Maximum oil rate achievable at various production well bottomhole temperatures.

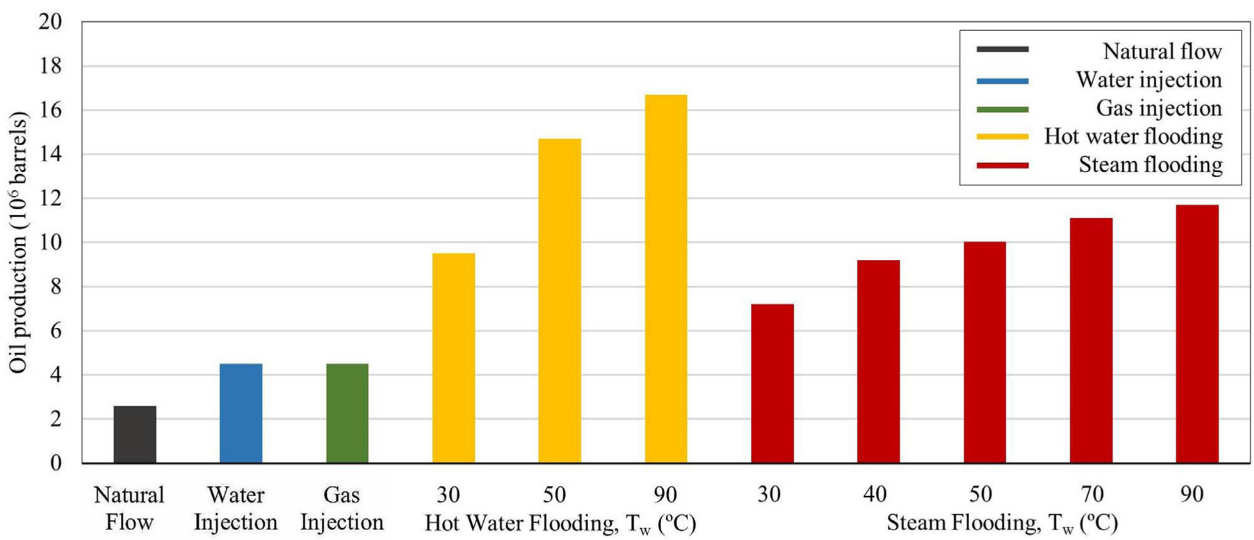


Fig. 18. Cumulative oil production in 30 years through different methods.

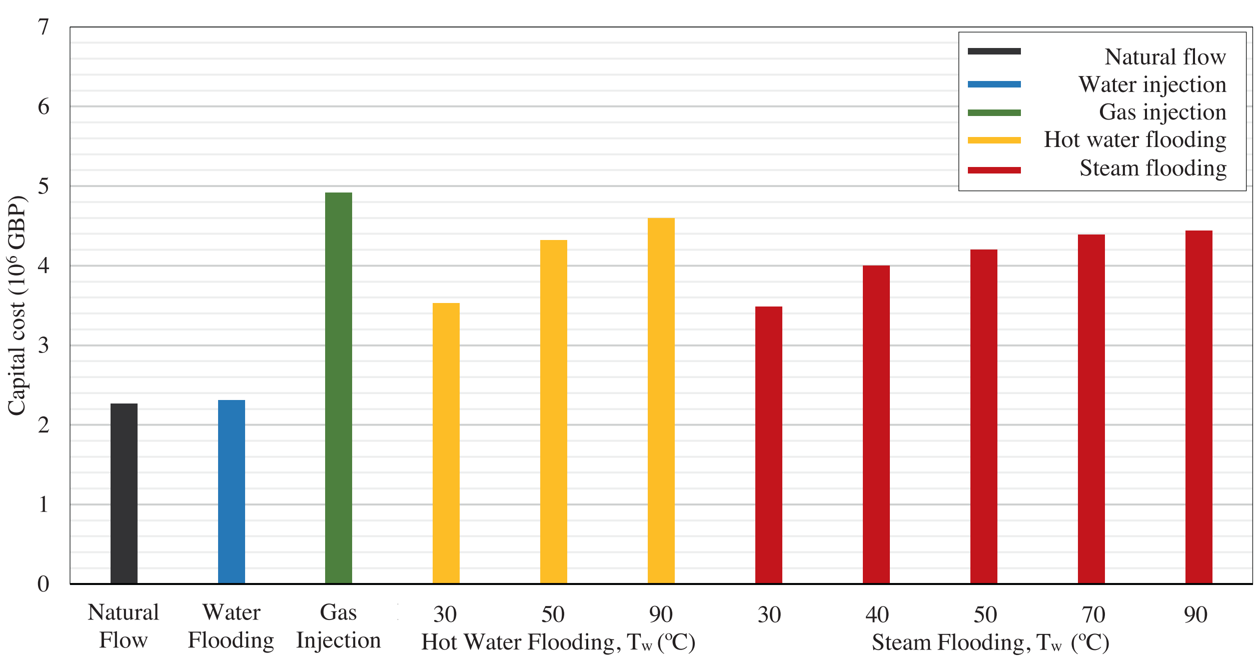


Fig. 19. Capital cost (CAPEX) of the IOR methods considered in the case study.

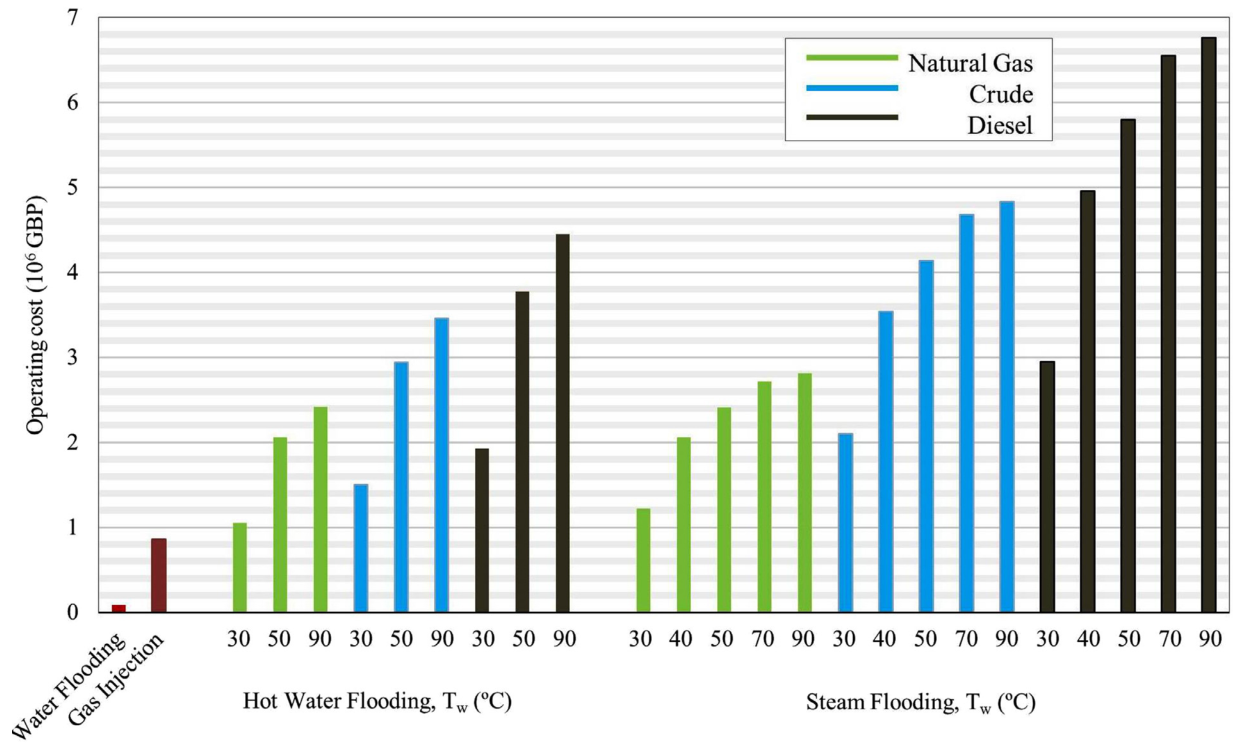


Fig. 20. Operating cost (OPEX) of the IOR methods considered in the case study (mid water cut profile).

water flooding. Moreover, since more powerful pumps, heat exchangers and boilers are required for higher hot water as well as steam injection temperatures, the CAPEX required increases as a function of production well bottomhole temperature.

Fig. 20 illustrates that the operating expenditure (OPEX) for thermal methods is several times higher, hence they emerge as significantly more expensive due to the continuous thermal energy provision requirement. Contrary to the foregoing CAPEX trend for thermal methods, hot water flooding has a lower OPEX compared to steam flooding: this is expected because in hot water flooding, the only thermal requirement is sensible heat, while steam flooding requires the provision of latent heat of evaporation in addition to the required sensible heat.

Another important observation emerging from Fig. 20 concerns the effect of fuel selection and availability on project economics. Natural gas is the preferred source of energy due to lower cost, a general trend which has been clearly confirmed by this case study: nevertheless, it is not always readily available in heavy oil projects due to the low GOR of heavy oil reservoirs. Therefore, another energy source should be considered for use: accordingly, it is more economically viable to burn some of the produced heavy oil rather than purchasing diesel if natural gas is not available, even though this fuel provision remedy is likely to result in a lower oil revenue, hence a lower production project net profit.

Despite the fact that information on production capacity and associated technology costs can provide useful indications regarding IOR method suitability, only the simultaneous consideration of both can facilitate the reliable comparison of IOR methods and allow for conclusive comparisons of the effect of production variables (such as water cut and temperature variation) on heavy oil field productivity and investment requirements. Therefore, the NPV of each scenario has been computed via RAVE, using the corresponding CAPEX and OPEX estimations hereby obtained.

The heavy oil production rate is theoretically expected to decrease with increasing water cut, leading to a reduction in project NPV and consequently reduced profitability. However, the degree to which the water cut profile affects the NPV of different methods cannot be a priori known. Therefore, graphs of scenarios for variable water cut profile (with all other conditions kept identical) have been plotted, in order to quantitatively evaluate the sensitivity of each IOR method to water cut variation. Fig. 21 illustrates that the NPV of the steam flooding can be increased by about 40% by controlling the reservoir behaviour and the water production rate: consequently, IOR methods which allow for control of the water breakthrough should be considered, and a detailed technoeconomic analysis of their costs and benefits during steam flooding processes is recommended as a conclusion (beyond the scope) of the present study.

The effectiveness of cold IOR methods has also been compared with natural oil flow, using the model results obtained for all three water cut profiles of cold IOR methods. Fig. 22 clearly demonstrates that CO_2 flooding has a lower NPV than natural flow, with the exception of the late water cut profile. The significantly lower NPV values obtained for CO_2 injection in comparison to hot water flooding (WF) and steam flooding (SF) clearly illustrate the current issue with heavy oil CO_2 flooding, which is the high cost of CO_2 and gas compression. However, it should be noted that in the case of CO_2 flooding, it has been assumed that there is no miscibility and solubility of CO_2 in the produced heavy oil [3]. A more detailed reservoir simulation would capture the expected increase in performance of CO_2 flooding due to the slight increase in oil production caused by the limited miscibility of CO_2 with heavy oil.

Water flooding emerges as having superior economic performance than natural flow as well as CO_2 injection, even with a more aggressive water cut. This superiority over natural flow is justifiable as a result of maintained reservoir pressure provided by water flooding. In comparison with CO_2 flooding, the improved performance of water flooding is attributed to the lower cost of water and pumping energy compared to CO_2 and compression energy, respectively. Because water flooding has a higher NPV compared to natural flow, it has been decided to compare it with thermal IOR methods, in order to verify whether the application of

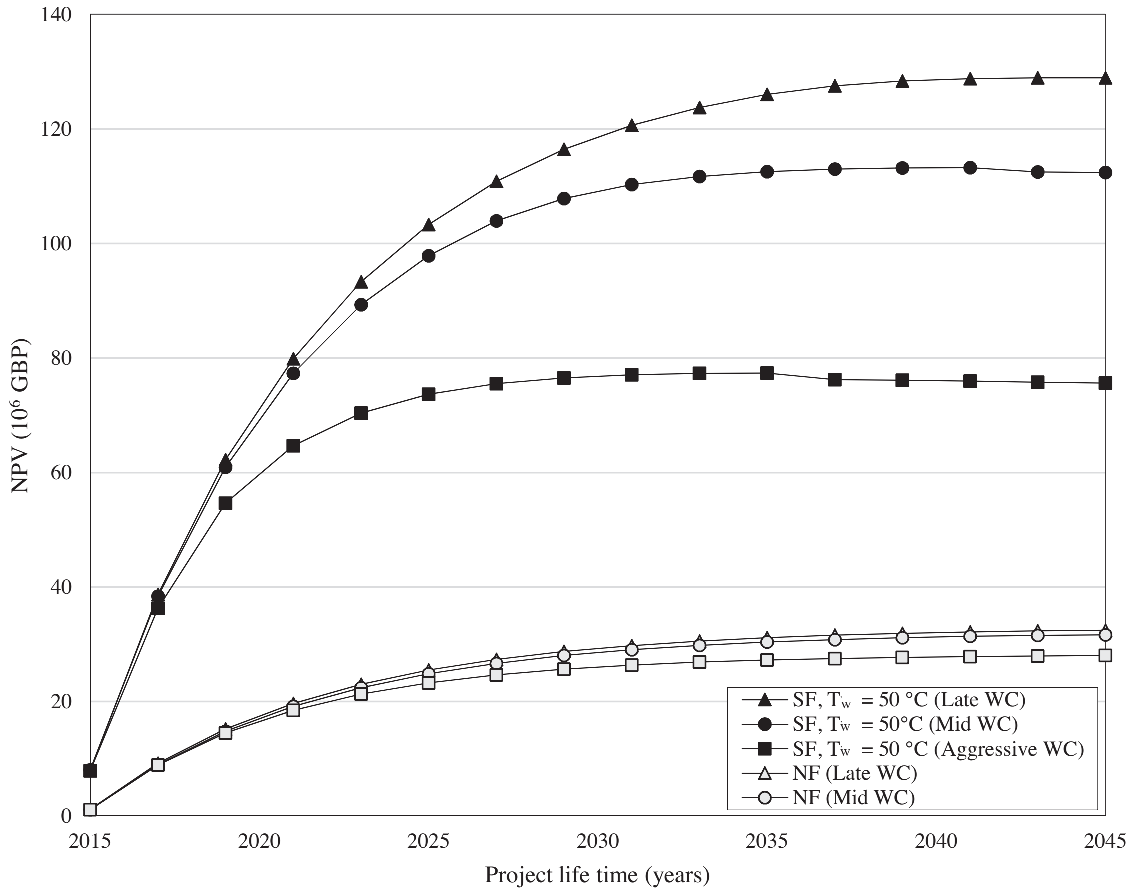


Fig. 21. Effect of water cut on project NPV for natural and steam flooding methods (based on natural gas use).

thermal methods is justifiable: since presenting and comparing all thermal method scenarios is not practical, the most representative scenarios (coldest and hottest thermal methods at medium water cut profile) have been illustrated and discussed.

Fig. 23 reveals that all thermal methods have considerably higher NPV values compared to water flooding, as a result of significantly higher oil flowrates. Nevertheless, this clear NPV gap between thermal and cold methods may be resolved as appreciably smaller over the course of actual heavy oil production projects, because the M&S model does not consider the initial stages of production: during this transient period, steam or hot water comes into contact with cold heavy oil, whose flowrate is initially insignificant, even though the heating medium is injected at a constant rate.

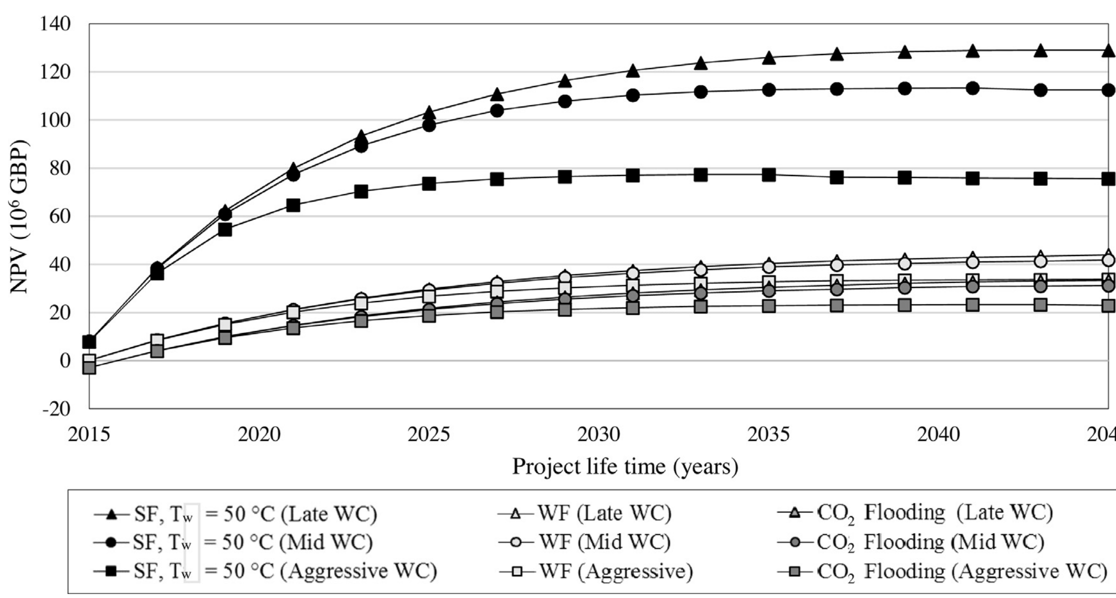


Fig. 22. NPV comparison of cold IOR methods reviewed in the case study (based on natural gas as the fuel).

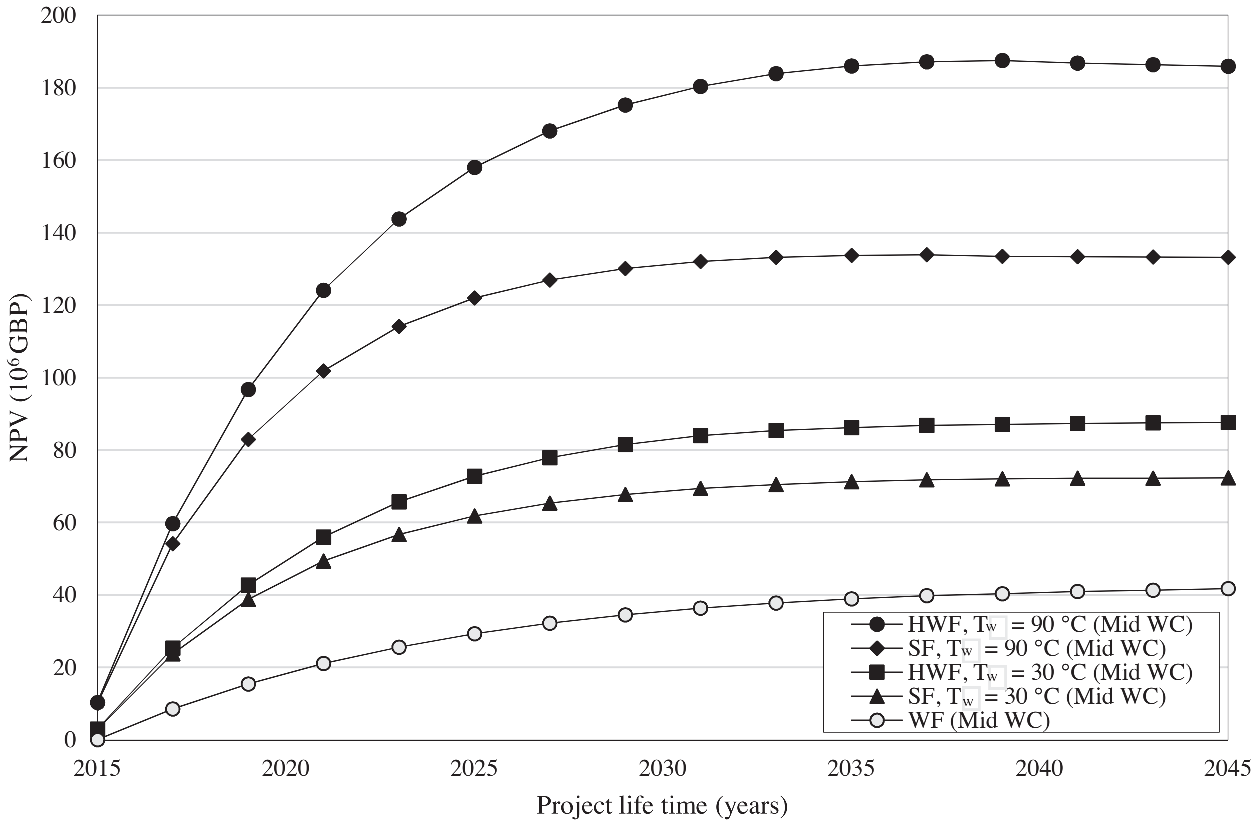


Fig. 23. NPV comparison of thermal IOR methods and water flooding.

Another important observation is the higher NPV of hot water flooding in comparison to steam flooding: as the API gravity of the heavy oil considered has been assumed to be 12°, steam flooding is expected to perform better than hot water flooding. There are two main factors to which this deviation between literature predictions and present case study results can be attributed:

1. The assumption employed is that the reservoir pressure profile has a decreasing slope, but this simplification may not be valid in several steam flooding projects.
2. The effects of hot water flooding and steam flooding on reservoir behaviour are assumed identical according to the M&L model: in reality, the heat transfer is more efficient from steam to heavy oil, in comparison to that from hot water to heavy oil.

The effect of water cut on the production period has been evaluated, on the basis of the assumption that the heavy oil field should be abandoned when the discounted cash flow of the project becomes negative. None of cold methods reached abandonment time during the considered lifecycle of 30 years of production: this observation is justifiable by the fact that constant reservoir pressure maintains the heavy oil flowrate (for pressure maintenance methods), while the heavy oil production process eventually emerges as cost-free in case of implementing a natural flow IOR method, due to the hereby assumed negligible OPEX.

Finally, when inspecting model results for the case of hot water flooding for both bottomhole temperatures of 30 °C and 50 °C, we observe that the abandonment time is reached only at aggressive water cut, regardless of the boiler fuel type considered. Nevertheless, for a production well bottomhole temperature of 90 °C, all scenaria reach a decreasing NPV at some point during the project lifecycle. For steam flooding, with the exception of the scenario for late water cut at a bottomhole temperature of 30ºC using natural gas, all scenarios reach an abandonment time during the project lifecycle. Fig. 24 presents the most interesting effects of fuel type

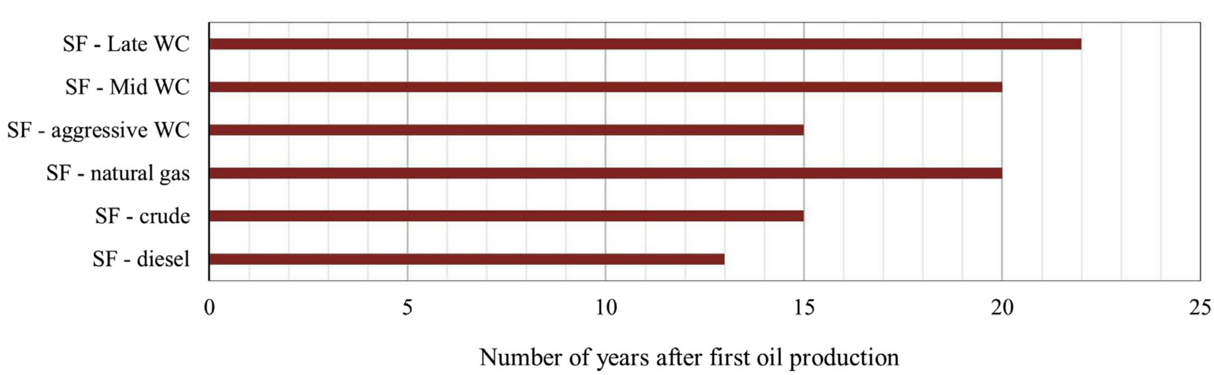


Fig. 24. Effect of fuel and water cut on project life (sample example for steam flooding).

selection and water cut on the project life until the abandonment time; all other scenarios considered follow similar trends.

6. Conclusions

This paper presents a database and workflow integration methodology based on two core software applications (PIPESIM and RAVE/Excel) which are established, fundamental tools for any oil and gas field appraisal and development endeavour. A step-by-step procedure on how to set up and connect the PIPESIM model with the RAVE/Excel environment for heavy oil production and fluid injection is presented; to the best of our knowledge, such a method has hitherto not been analysed in a dedicated publication. This procedure can serve as detailed guidance to software developers who are relatively new to oil and gas industry, in order to set up and evaluate the interoperability of common software tools which are broadly used in hydrocarbon field technology development projects. Furthermore, it can quickly familiarise those readers who have programming expertise outside the oil and gas industry with the basics of IOR petroleum extraction methods, and their relative suitability which can be determined on the basis of the variable hydrocarbon reservoir conditions.

Most of the quantitative analysis observations resulting from the case study results are in agreement with the theory and matched the expectations. The most noticeable unexpected behaviour of thermal flooding model has been the dominance of hot water flooding over steam flooding. This observation would have been expected if the oil API gravity was high but for an API gravity of 12, steam flooding was expected to be the more viable option. This response highlighted two potential flaws in the modelling:

1. The reservoir pressure profile assumption has not been confirmed as realistic;
2. The M&L model has inevitable limitations with respect to accurate reservoir performance modelling.

In the case of cold methods, the most significant observation is the superiority of natural flow and water flooding over CO_2 injection. Despite the fact that this trend is not surprising with respect to water flooding, CO_2 injection may actually perform better than natural flow if the miscibility and solubility of CO_2 in water is explicitly considered.

In conclusion, the methodology and IOR project database developed and presented in this paper can be used as a two-level preliminary project screening model;

1. Initially, using the IOR application boundary conditions, the suitability of all currently available heavy oil IOR methods must be analysed.
2. If the comprehensive technoeconomic evaluation process suggests that pressure maintenance or thermal flooding IOR methods are suitable for the heavy oil reservoir conditions, the production project NPV can be calculated based on the required oil production rate and fluid injection rate, using a combination of the M&L model and established software tools (RAVE, PIPESIM).

The reservoir behaviour can be simulated more accurately for the purpose of providing high-fidelity inputs to both the thermal flooding and pressure maintenance models, provided that advanced reservoir simulators (e.g. ECLIPSE) are available; the procedure presented in this paper can of course be efficiently integrated with such high-fidelity production system simulation results, in order to rapidly and systematically evaluate the technoeconomic potential of heavy oil production from a given field. The methodology presented enables such a reliable evaluation at low cost and with high time efficiency.

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