



Review article

A review of VAPEX recovery technique: Mechanisms, driving models uncertainties, and enhancement factors analysis

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ABSTRACT

VAPEX is the promising heavy oil/bitumen recovery method with solvent diffusion into heavy oil/bitumen as a primary driving mechanism. The estimated oil recovery factor ranges from 41 ~ 75 % after utilizing variable vapour solvents, including propane, butane, methane, and carbon dioxide. Other contributing driving mechanisms revealed are capillarity and interfacial tension, with a limited knowledge of them, which emphasizes using programming language software for their analysis. Formulated analytical models were based on the equations' insertion of a constant molecular diffusivity coefficient and constant thickness of transition zone parameters, which are both functions of solvent concentration in heavy oil/bitumen, reflecting that there are study gaps which involve concentration dependence diffusivity parameters in the models to be fulfilled. Single or mixed solvents are utilized, with choices based on recovery performance characterization. Maximum recovery, in most cases, was found while solvent injection pressures approach their dew/vapor pressure with the possibility of asphaltene precipitates, which might plug small pores and reduce recovery factor. Lack of solvent mixture phase diagrams and pressure composition relationships was noted in this review study. Simulation software does not entirely mimic the physical processes and faces challenges, including longer computing time due to the small grid block sizes used. A lack of actual field permeability was noted in most reviewed experiments and simulations. Oil viscosity, solvent injection pressure and rate, interfacial/capillarity effects, and reservoir permeability are the most explored factors that affect VAPEX, which needs sensitivity analysis for performance optimization. This critical review will help identify the next challenges and opportunities in the VAPEX technique for heavy oil and bitumen production in the future research.

1. Introduction

Due to a decline in conventional oil resources and increasing demand for fossil fuels globally, the exploration of unconventional resources, including heavy oil/bitumen, is worth attention [37,45,34], as recent statistics show that the unconventional oil reserves, which include heavy oil, extra-heavy oil, and bitumen, exceed six trillion barrels of oil, approximately three times greater in volume compared with the world's conventional oil and gas reserves[31,45,89,96]. In descending order, the United States, Canada, Venezuela, and China are the recently leading countries globally in heavy oil exploration and production [36,91].

The started-produced fields recover heavy oil/bitumen based on thermal methods, mainly steam or in-situ fire combustion [11,15,16,27,90]. The better recovery efficiency of the thermal methods is usually associated with some reservoirs' conditions, including thin formations with estimated best performance when formations are < 200 m from a sea level/surface, while less recovery efficiency was also explored in the deepest formations[83]. Bottom aquifers or overlying water and clay minerals, especially when clay contents are > 10 %, also hinder the methods' applicability[40]. VAPEX is one of the promising technologies that can replace thermal methods in such unfavorable conditions[40].

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The oil drive mechanism is mainly controlled by the mass transfer of a vapour solvent under molecular diffusion, but convective dispersion can also be present [9]. General analytical models and recently subsequent models developed were based on diffusion theories as the primary mechanism for recovery of heavy oil/bitumen with several identified uncertainties, including the neglect of concentration-dependent diffusivity coefficients to simplify mathematical formulations of these models while in reality, these values depend on volume fractions (concentration) of solvents in heavy oil/bitumen as revealed by Boustani and Maini [9], Fayazi and Kantzas [31], Perkins and Johnston [70]. Tuhinnuzaman [84] conducted simulations by including an effect of capillarity Xu [93] conducted simulations by including the impact of the interfacial tension and both observed the closed matched results as the ones obtained from experiments, which then reflected the significance of the inclusion of the two mechanisms in the VAPEX performance analysis. However, Lowman [53] assessed the impacts of the most critical factors, which are diffusion, capillary pressure, and interfacial tension, and found that the resulting partial differential equations can be programmed using Python software. After simulating three conducted experiment environments/conditions, they found the results were closer to the experiment results, which emphasizes that more research in this area is required. Other additional anticipated recovery drive mechanisms are enhancement during the rising of the solvent chamber, development of transient mass transfer across the interface, and increased solubility due to solvent vapour condensation in the fine capillaries Boustani and Maini [9], which are also not yet critically and cleared discussed in the theories/literature which is then an encouraging study area in the future researches.

Several simulations have also been conducted mainly through the use of CMG (Computer Modelling Group Ltd.) software. However, there are some noticeably significant limitations of the used commercial simulators [95], including too long computation time, which might not be feasible to the actual field reservoir scale because of the small grid block sizes used to capture a transition zone which is a main controlled part for diluted oil/produced oil recovery performance analysis. Apart from that, the values of the highest permeability used in the laboratory experiments usually end with minimum pressure gradients, which are quite complex to read by commercial numerical solvers, leading to significance numerical hurdles [95].

During the process of vapour injection, once the operating pressure approaches a solvent dew/vapour pressure asphaltenes precipitates might happen, which is the favourable best functional condition for the extreme viscosity reduction of the heavy oil/bitumen and enhancement of more oil recovery [86]. Precipitate formation might end up with reservoir rock permeability reduction, especially in tiny pores, as reported by Luo and Gu [54] and subsequent decreasing oil recovery factor [35,47,55]. Therefore, proper solvent selection, values of porous media permeability, and operating condition characterization optimization are crucial subjects to consider for the best VAPEX recovery performance projects. Hybrid solvent mixtures, which include butane (C_4H_{10}) and propane (C_3H_8), and other derivatives involving methane (CH_4), propane (C_3H_8), and carbon dioxide (CO_2) were practiced as documented by Sun et al. [82]. Lighter component gases added advantage as carrier gases [63] and were adopted to minimize heavier hydrocarbon solvent costs [85]. The characterization process of these hybrid systems in terms of phase diagrams and pressure-composition relationships is vital in solvent ratio optimization to avoid in-situ condensate/liquid solvent formation due to the reservoir temperature and operating pressures, which can hinder solvent extraction efficiency leading to a lower oil recovery factor. However, the information about these two subjects for VAPEX-used solvents is lacking in the literature.

Moreover, several factors have been explored to affect a heavy oil/bitumen recovery factor by VAPEX, including a solvent type, solvent injection pressure, solvent injection rate, oil viscosity, reservoir permeability, interfacial tension/capillarity effects, viscous fingering, and wells configurations. Each of the factors had a significant impact on

the heavy oil/bitumen recovery factor (Chen et al., 2022), and, therefore, sensitivity analyses for these factors are emphasized to be conducted, hence achieving the best VAPEX process performance, which means the evaluation of the VAPEX process for optimal fluids and operation parameters determination.

2. VAPEX recovery technique and mechanisms

(VAPEX) was first suggested by Butler and Mokrys [12] as a robust synthetic recovery method of heavy oil and bitumen in 1991. The process involves using two horizontal wells (one at the top part and another at the bottom) in a specified heavy oil/bitumen reservoir targeted zone. The top well injects solvent, and the bottom delivers the less viscous oil after being diluted by solvent and transferred to the surface for further processes. Solvents in the form of the gas state are the ones applied compared to those in the liquid state due to the lower amount of solvent to be needed in the gas form compared to the liquid form, also resulting in further higher rates of diffusion and giving a high-density contrast which is the best condition for gravity drainage oil recovery mechanism [39,41].

The working principle of VAPEX is mainly the reduction of heavy oil/bitumen viscosity by removing specifically higher molecular weights asphaltenes and insoluble solids from corresponding heavy oils/bitumen [8]. However, some interfacial tension reduction and oil swells might also be associated with the VAPEX process [83]. Traditionally used solvents in the VAPEX processes are propane, butane, carbon dioxide, methane, pentane, or a mixture of the solvents, but also recently, there is the prospect nominated solvent, which is dimethyl ether in the case of Warm VAPEX, which is soluble in water compared with the traditional solvents which are insoluble in water [16].

As stated earlier, gravity stimulates oil from the top injection well in the reservoir to the bottom production well after a mainly mass transfer mechanism (especially diffusion/dispersion of solvent molecules into heavy oil). The process can also be styled as two transport mechanisms, in which the first part involves the transport of solvent into the heavy oil by diffusion to reduce the viscosity of the heavy oil, hence facilitating gravity forces to overcome capillary forces, enabling the second transport mechanism which is transporting the less viscous oil to the production well by gravity [71]. Fig. 1 elaborates on the mechanism. While solvent molecules diffuse into heavy oil/bitumen, oil's viscosity decreases. The modified lower viscous oil (diluted oil) flows down by gravity effect to the production well [75].

Solvent molecules have to diffuse into the heavy oil/bitumen phase. Therefore, molecular diffusion theories are recommended to govern the process models [21]. The solvent molecules' dispersion into heavy oil might sometimes happen apart from diffusion. Knowledge of diffusion for solvent into heavy oil/bitumen is limited in the petroleum field;

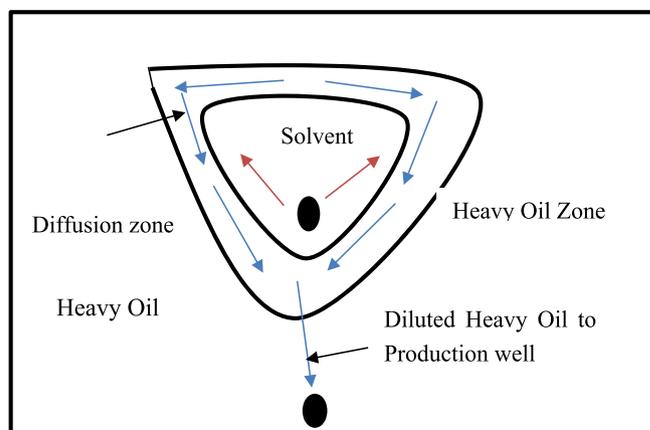


Fig. 1. Cross Section of VAPEX Process Drainage Phenomena [85].

therefore, different empirical and semiempirical correlations used in other systems were adapted to determine diffusion coefficients in the petroleum field, too[21].

Upreti et al. [85] presented planning guidance between SAGD and VAPEX for heavy oil reservoirs; their analysis found that VAPEX operations required less energy consumption than SAGD operations for most cases. However, condensation of fresh water from steam stimulates the formation of clay swelling and reduces oil relative permeability, while VAPEX does not have such obstacles to production. Carbon dioxide (CO₂) emissions in SAGD operations are higher, which can be mitigated using VAPEX. Proposed traditional solvents that can be applied in VAPEX are commonly insoluble or sparingly soluble in water, which reflects no loss of solvents in water. At the same time, steam may be lost to water [24].

The reported challenge of the process is the small initial recovery rate caused by the slow nature of the diffusion process [57]. But also, asphaltene precipitation formation due to reaching a certain level of operating conditions for a given set of solvent-heavy oil/bitumen systems might induce the problem of pores plugging (reduction in rock permeability), ending up with the lower recovery of heavy oil/bitumen, even though of upgraded oil quality (most oil viscosity reduction phenomena to facilitate best accessible flow), especially for low permeability porous media. Thus, selecting the type of solvent and operating parameters optimization becomes one of the critical issues to be analyzed in case of the method application in the field [68]. Moreover, there are still challenges/gaps existing in the VAPEX process in the prediction methods of oil recovery rates from solvent-heavy oil/bitumen systems due to several uncertainties involving the mass transfer and convective flow mechanism during the recovery process [60].

2.1. Diffusion of solvents into heavy oil/bitumen

Three steps generally govern the diffusion of vapour solvents in heavy oil/bitumen. The vapour solvent moves toward the vapour-heavy oil interface in the first step. In the second step, the vapour solvent crosses the interface, where it enters the heavy oil phase (the volume of solvent vapour at the interface is affected by vapour solubility at the current conditions, assuming there is an instant equilibrium at the interface). The third stage is the component diffusion into the oil phase, resulting in oil swell, a function of mutual diffusion coefficients. By definitions, solubility is the measure of the ability of the liquid phase to dissolve the gas phase, diffusivity coefficient is the parameter that controls the rate and extent of gas phase mass transfer into the liquid phase, and swelling is the change in volume of the liquid phase due to gas dissolution [31]. Diffusivity coefficients are usually functions of solvent concentrations in the heavy oil phase, as documented by Babak et al. [6], Fayazi and Kantzas [31], Ghanavati et al. [33].

The diffusion of the gas solvent across the sharp interface due to the random movement of vapour solvent molecules into an oil phase under no change in volume conditions upon the mixing of two fluids, which is the total transport of one of the constituents across an arbitrary plane can be represented by Fick's diffusion equation as:[70].

$$\frac{dG}{dt} = -D_o A \frac{\partial c}{\partial x} \quad (1)$$

Where;

G = Quantity of material diffusing across a plane
 t = Time, sec
 D_o = Molecular diffusion coefficient, cm²/sec
 A' = Cross-sectional area for diffusion, cm²
 c = Concentration or solvent volume fraction and
 x = Distance, cm

Equation (1) reveals that diffusion coefficients (D_o) are a function of diffused phase concentration. For comprehensive accuracy of equation

(1) before integration, the relationship between diffusivity coefficient and solvent concentration must be defined, as in the case of the example shown in Fig. 2 where diffusion coefficients of various solvents were varying with solvents concentrations as experimented by Fayazi and Kantzas [31]. Still, the mathematical description of such behaviour with variable diffusion coefficients in equation (1) seemed quite complex. Therefore, it is common to use a practical approximated average value of the diffusivity coefficient to represent diffusion behaviour. In some situations where the diffusion coefficient slightly varies with concentration, using D_o at 50 % by fraction volume ratio of gas-liquid phase mixture is convenient.

Estimation of the molecular diffusion coefficients of gases in heavy oil/bitumen relies on experiments using two general methods, which are constant volume and constant pressure methods. The methods face challenges that need more improvement to have reliable estimates. Some of these challenges are elongated experiment duration due to the low diffusivity of solvents in heavy oil/bitumen, the low solubility of solvents vapour in heavy oil/bitumen resulting in the insignificant rate of mass transfer, etc., [43].

If the steady state condition is reached, equation (2), which is sometimes known as the straight capillary model, can be again written as:

$$\frac{G}{t} = -D(\text{Area open for diffusion})\left(\frac{\Delta c}{L}\right) \quad (2)$$

Where;

D = Apparent diffusion coefficient
 L = Total length of the tube

In reservoir engineering, the defined apparent diffusion coefficient in a porous medium, D in equation (2), is based on the average cross-sectional area open for diffusion and the system's overall length. Fluids in the porous media are assumed to move on average at about 45° to the net flow direction. If a fluid has travelled a net distance of L , it is then actually assumed to have travelled an average length of about $\sqrt{2}L$. Then,

$$\frac{D}{D_o} = \frac{1}{\sqrt{2}} = 0.707 \quad (3)$$

Apart from equation (3), Brigham et al. [10] suggested a more sophisticated and comprehensive approach equation that gives the relationship between porous media resistivity factor and diffusivity coefficients. The equation can be used for both cemented rocks and

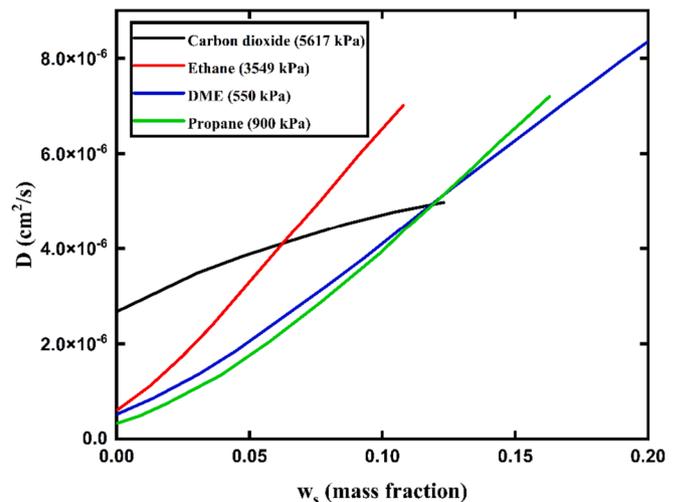


Fig. 2. Solvents Diffusion Coefficients in Heavy Oil as a Function of Solvents Mass Fraction [31].

unconsolidated rocks. It was validated by several researchers, including Scott and Dullien [76]. The equation is expressed as:

$$\frac{D}{D_o} = \frac{1}{F\phi} \quad (4)$$

Where,

F = Formation electrical resistivity factor and
 ϕ = Fraction porosity

Indeed, the mechanisms behind affecting the mass transfer of the solvent into heavy/bitumen have not yet been clearly understood/evaluated. However, conducted experiments and simulations reveal that diffusion phenomena are not the only scenario to consider, but dispersion spreading phenomena might also be present to account for the final value of the coefficient of diffusivity of solvent molecules into heavy oil/bitumen bulk volume [70].

The difference between diffusion and dispersion is that diffusion is associated with the random movement of molecules, commonly termed Fickian motion, in which the system attains maximum disorder. Therefore, solutes or isotopes in one region/phase where molecules concentration is higher will dissociate into another region/phase where concentration is lower to decrease that “disorder,” while in dispersion phenomena, dissolved solutes in one region/phase where concentration is higher disperse into another region/phase due to velocities variation in the heterogeneous media [19,78].

2.2. Asphaltenes contents and heavy oil/bitumen viscosity characterization

Crude oils comprise multiple component systems that involve thousands of individual compounds. The most commonly characterized groups are saturates, aromatics, resins, and asphaltenes, abbreviated as SARA. It has been shown that there is a relationship between crude oil viscosity and the quantity levels of these chemical groups in crude oil. Oil viscosity increases along with the significant portions of the highest molecular weights, mostly resin and asphaltenes [49,54,88]. Asphaltenes, the highest molecular weight in heavy oil/bitumen, stimulates oil to become more viscous. Asphaltene removal from heavy oil is one of the most effective techniques for reducing heavy oil/bitumen viscosity [38].

Fig. 3, as experimented by Luo and Gu [54], reveals that asphaltene contents, as shown by fractional volumes, play a more significant part in the final absolute values of heavy oil/bitumen viscosity. Again, under variable temperatures, the final values of viscosity will be altered at a given pressure. It can be seen that, for a specific level of asphaltenes

content, the higher the heavy oil temperature, the lower the viscosity value, and vice versa is also true. However, it is also reported that viscosity decreases at a specific value of heavy oil temperature as the asphaltenes contents diminish. The scenario was also reported by Li et al. [48] with the addition that the temperature dependency heavy oil viscosity can be further modelled by the Arrhenius equation, which is given in equation (5)

$$\mu(T) = \mu(T_o) \exp \left[\frac{E_a}{R} \left(\frac{1}{T} - \frac{1}{T_o} \right) \right] \quad (5)$$

Where

$\mu(T)$ = Heavy oil viscosity at a specific temperature in K
 $\mu(T_o)$ = Heavy oil viscosity at an original temperature in K
 E_a = Activation energy in J/mol
 R = Universal gas constant in $J.mol^{-1}.K^{-1}$

Models can also be developed from the behaviour shown in Fig. 3, which includes the recently developed model by Sinha et al. [81], which gives the relative viscosity (ratio of crude oil viscosity at a specific temperature to the viscosity of the same crude oil at zero asphaltenes content for the same temperature) after studying the asphaltenes volume fraction changes of Canadian, Iranian and Saudi Arabian heavy oils at different working temperatures ranging from 20 – 240 °C. However, the formulated equation was exponential for all of the used types of heavy oils with a single estimated constant parameter that varies significantly with temperatures for a given heavy oil type and with minor changes for a given temperature in each heavy oil type. Solvents can reduce the asphaltenes content from the heavy oil/bitumen; hence viscosity upgrading for easy flow in the reservoir. For instance, heptane was mixed with Canadian Athabasca bitumen, and asphaltenes were precipitated up to 13 % by weight (wt). In contrast, when pentane was used for the same oil type, up to 20 % wt asphaltenes precipitates from the oil solution, which reveals lighter hydrocarbon solvents have the highest capacity of forming asphaltenes precipitation compared with heavier ones [94].

A successful project of solvent-heavy oil/bitumen will require detailed clarification of the solubility and diffusivity of the solvent-heavy oil/bitumen system since they are the vital parameters for the recovery performance analysis [72,77]. The most common solvents applicable in the VAPEX processes are propane, butane, and a mixture of propane and butane, as Sadeghi Yamchi et al. [94] reported. Carbon dioxide gas (CO₂) and methane (CH₄) can also be solvents. The essential physics in the VAPEX process mainly includes mixing solvent and heavy oil/bitumen at the solvent-heavy oil interface at the vapours chamber boundaries, and probably, the precipitation of asphaltenes might happen depending on solvent concentration and pressure. The mixing of solvent and oil is through molecular diffusion and convective dispersion. Asphaltenes precipitation was mainly reported to occur often with propane-rich solvents, which provides a significant in situ upgrading of heavy oil and bitumen viscosity reduction [66].

Solvent selection is the primary task that needs to be performed to optimize recovery [80], which is preliminary decided by two commonly known factors, which are the solvent diffusion rate into heavy oil/bitumen and solvent mixing quality, which refers to minimum asphaltenes precipitation while more excellent solvent-heavy oil/bitumen viscosity reduction capability [59]. Marciales and Babadagli [58] conducted experiments based on Barea sandstone core samples using three heavy oil types with three orders of magnitude values of viscosities and liquid solvents with carbon numbers ranging from C₇ to C₁₃. Upon outcomes, the oil recovery factor was found to be a function of diffusion rate and mixing quality, which gives better results for the lighter solvents (the one belonged to low carbon numbers), which showed higher diffusion rates with the emphasis on the analysis of mixing quality factor of them before solvent selection. Extremely dissolution/solubility of the

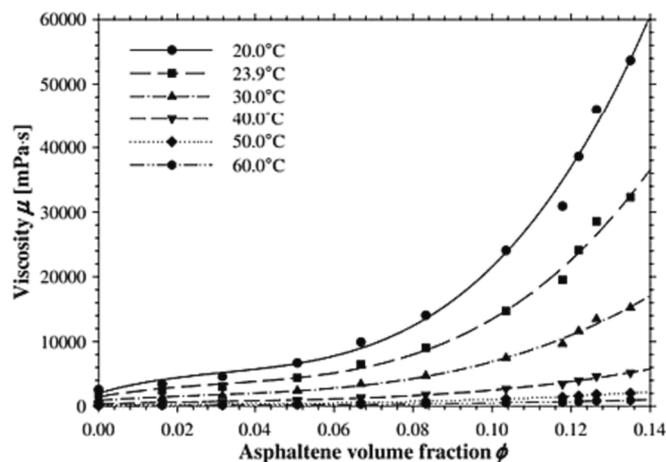


Fig. 3. Measured Viscosity Values under Variable Asphaltenes Volume Fraction at Different Constant Temperatures [54].

injected solvent phase in heavy oil/bitumen yielding to excessive in-situ upgrading of the heavy oil/bitumen, which refers to a higher degree of the heavy oil/bitumen viscosity reduction, higher level of reservoir pressure maintenance for continuation oil drive, penetrating and diluting deeper section of heavy oil/bitumen, etc. [86].

A significant portion of heavy oil viscosity reduction can be achieved by deasphalting phenomena (asphaltenes removal). That viscosity reduction can be up to tens to hundreds of times compared with the previous one, specifically favourable at low temperatures. However, asphaltene removal efficiency depends on the choice of precipitants (solvents), which can provide a way of controlling viscosity [38]. Experiments conducted by Ilyin et al. [38] indicate a greater quantity of asphaltenes can be precipitated by using the solvents/precipitants that had a solubility parameter value of lower than $16.5 \text{ MPa}^{1/2}$ as shown in Table 1 with a reference of solvents solubility parameter indicated in Table 2, and solvent is supposed to be added sufficiently in excess with the crude oil.

From Tables 1 and 2 δ stands for total interaction solubility, which combines the impacts of polar (δ_p), dispersion (δ_d), and hydrogen bonds (δ_H) interactions [73].

It has been recognized by Mokrys and Butler [64] that once the concentration of the solvent is high enough in the heavy oil before the solvent-diluted oil reaches the production well, precipitation of asphaltenes could happen, leading to in-situ heavy oil deasphalted that improve the quality of heavy oil viscosity to flow. These precipitates might again plug tiny pores and significantly reduce the precipitated pore's area permeability, hence lower oil production rates. Asphaltenes precipitation might happen during the VAPEX process when the light hydrocarbon solvents are used at higher operating pressures [55]. Das and Butler [23] found that deasphalting causes further viscosity reduction when the operating pressure approaches or is higher than the propane vapour pressure at reservoir temperature. They used propane as the solvent to extract heavy oil in a Hele-Shaw cell experiment. They noticed that deasphalting started when the operating pressure was $759 \sim 827 \text{ kPa}$, while the vapour pressure was 841 kPa at $20 \text{ }^\circ\text{C}$. They furthermore described that higher solvent concentrations are required for the onset values of deasphalting, and the onset values vary with the solvent type used. It had also recognized that the oil flow rate of the VAPEX process were not affected by the precipitates and the solvent gas by passed the precipitates and continue to diffuse in the heavy oil [55].

On the other hand, Butler and Mokrys [14] performed an experiment using a 2-D physical model. Lloydminster heavy oil was extracted from the model by propane solvent, the operating pressures were $708\text{--}984 \text{ kPa}$, and the operating temperature was set to $20 \text{ }^\circ\text{C}$. Upon analysis, it was found that operating pressures had a role of deasphalted and also affected the oil production rate. Operating at lower operating pressures less than the propane vapour pressure, 841 kPa at $20 \text{ }^\circ\text{C}$, yields a lower production rate due to lower solvent concentration in the heavy oil. Again, suppose the operating pressures are far higher than propane vapour pressure. In that case, the production rate of the heavy oil is reduced due to asphaltene particle deposition on the glass model, hence lower model permeability [55]. An investigation conducted by Haghghat and Maini [35] reveals that in-situ deasphalting in lower permeabilities porous media could result in severe permeability

Table 1

The Influence of a Precipitant on the Measured Content of Asphaltene in Oil, its Intrinsic Viscosity and the Relative Viscosity of Deasphalted Oil [38].

Precipitant Name	Solubility/ δ ($\text{MPa}^{1/2}$)	Percentage in weight (%) asphaltenes removed	$\eta_{oil}/\eta_{deasphaltene}$
DEE	15.6	5.47	1.62
Heptane	15.3	7.52	2.5
Pentane	14.5	14.08	6
DIPE	14.4	10.90	14.7
HMDSO	12.4	24.89	44.4

Table 2

Characteristics of the Employed Solvents [38].

Solvent Name	Solubility, $\delta \text{ MPa}^{1/2}$
Tetralin	19.8
DEE	15.6
Heptane	15.3
Pentane	14.5
DIPE	14.4
Propane	13.4
HMDSO	12.4

damage, which could hinder the production of deasphalting oil. The solvent used was propane, with a 40 % reduction of original asphaltene content in the heavy oil. This resulted in an 80 % reduction of initial oil viscosity, which is also associated with the formation damage (decrease in formation permeability). Again, when the injection pressure was lower than the propane vapor pressure by 64 kPa , no asphaltene were precipitated, while the oil production rate was down due to lower solvent concentration. Haghghat and Maini [35] finally realized that VAPEX processes need comprehensive evaluation in lower permeability formation or could not be a viable option due to significant oil production rate reduction. Li et al. [47] conducted a recovery performance test for heavy oil using pentane and propane solvents, which are both regarded as field scale candidates solvents, to study the impact of formed precipitants where it was found that pentane precipitants are solids and can affect the core sample permeability. In contrast, the propane precipitants are liquid phase with negligible pore plugging but significant capillary trapping. The recovery factor for propane solvent was 15 % higher than that for pentane. Luo et al. [55] performed eight tests to study the effect of the rock permeability, solvent type, and operating pressure on the asphaltene removal efficiency and precipitation characterization. Two solvents were used which are butane and propane. In the same operating conditions, propane was more efficient than butane, which means it had more asphaltene removal capability, leading to a higher degree of heavy oil viscosity reduction. It is also seen that when the operating pressure is at or slightly higher than the solvent vapor pressure, maximum solubility and diffusion of the solvent are achieved with precipitation formation and maximum viscosity reduction. Moreover, asphaltene precipitation results in severe permeability damage in low-permeability sand packs, leading to lower oil production and application of lower operating pressure results to lower asphaltene precipitation due to lower solvent concentration in the diluted oil, but the oil production rate was also lower. Therefore, it had concluded that the formation of asphaltene precipitates in VAPEX processes is a significant subject which should be taken into consideration in order to account for its advantages and disadvantages effect on the recovery of heavy oil during VAPEX process. Marufuzzaman and Henni [61] characterized propane-heavy oil interaction using the widely used CMG phase behavior package to adjust the Peng–Robinson equation of state (PR-EOS) in order to analyze the time dependent concentration data by means of a diffusion model. They found that the diffusion coefficients are direct proportional to the operating pressure and inversely proportional to asphaltene content in the heavy oil/bitumen. Other solvent mixtures were also utilized to analyze the recovery performances of heavy oil, Sun et al. [82] reported that the heavy oil recovery was upgraded in situ by both asphaltene precipitation and solvent mixtures dissolution (the used solvent mixture mole fractions in the study were 64 % CH_4 , 28 % C_3H_8 % and 8 % CO_2).

According to the explained interaction between solvents and asphaltene contents that are responsible for higher heavy oil/bitumen viscosity values, solubility and diffusivity data for solvent-heavy oil/bitumen data for the given operating conditions (temperature and pressure) are very crucial so as to achieve the desired heavy oil viscosity reduction. Phase behaviour characterization can be used as one of the tools for screening criteria on performance evaluation of vapour solvent's applicability in enhancing heavy oil recovery processes so as to

have a beneficial process design.

2.3. Theoretical analytical flow equation formulation for the VAPEX

The first analytical model that was developed to model the flow rate of diluted heavy oil/bitumen is the one introduced by Butler and Mokrys [13] based on thin-film flow theory, similar to the SAGD process, as shown in Fig. 4 [9].

Butler and Mokrys [13] combine Fick's law of diffusion and Darcy's flow equation in porous media to perform mass balance and momentum balance of solvent and bitumen at a control volume in the solvent region and solvent-heavy oil/bitumen interface with the following two main assumptions.

- The process of solvent transfer from vapour chamber to bitumen bulk volume is under pseudo-steady approaching steady state condition, meaning that, $\frac{\partial c_s}{\partial t} = 0$
- The interface between solvent vapour and bulk bitumen volume moves at a constant velocity, U_x , in x-direction.

Their final equation for the flow rate of diluted oil volume down to the production well is then,

$$q = 2L\sqrt{2kg\phi\Delta S_o N_s h} \quad (6)$$

Where,

- L = Wells length, cm
- k = Zone average permeability, in cm^2
- g = Acceleration due to gravity, in cm/sec^2
- ϕ = Zone average porosity, fraction
- ΔS_o = Change in oil saturation, fraction
- h = Effective drainage height in cm
- N_s = Dimensionless group, given by

$$N_s = \int_{c_{min}}^{c_{max}} \frac{\Delta\rho D_s (1 - c_s)}{\mu c_s} dc_s \quad (7)$$

Where again,

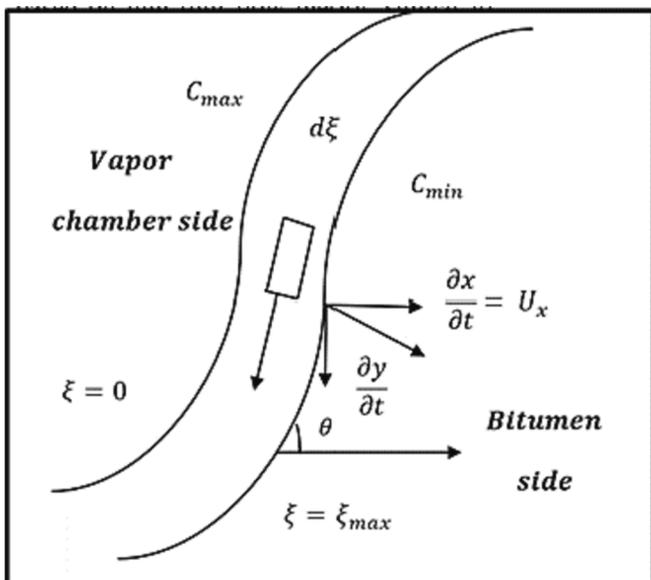


Fig. 4. Idealized Vertical Cross Section of VAPEX Model at Solvent/Bitumen Interface [9].

$\Delta\rho$ = Difference in the density of pure solvent and mixture solvent at concentration c_s in g/cm^3

D_s = Solvent molecular diffusivity in cm^2/sec

c_s = Solvent volume fraction, fraction

μ = Mixture viscosity with concentration c_s in cp

2.3.1. Experimental investigation of the developed analytical model

Butler and Mokrys [13] performed several experiments using Athabasca and Suncor bitumen with toluene as a solvent in a Hele-Shaw cell apparatus and found that the recovery rates they obtained from the experiments matched the expected range from their analytical model. A similar mathematical model developed by Butler and Mokrys [13] was again used by Dunn et al. [28] to study the recovery rates of Athabasca bitumen in porous sand packs media by injection of gaseous solvents, which is ethane (C_2H_6) and carbon dioxide (CO_2). However, the obtained rates from the experiments did not match with the ones from the model; hence, Dunn et al. [28] history compared their experimental rates and the one from the model and found diffusion coefficients are much higher than the known values from the literature as used previously in the analytical model. Regardless of the magnitudes of the diffusivity coefficients were considerably larger than classical diffusion coefficients of the literature, at least Dunn et al. [28] researchers tried to introduce the concept/idea of incorporating convective dispersion in the traditional analytical model to account the convective dispersion effect on the solvent mass transfer mechanism.

This implies that the early derived model for oil rate by Butler and Mokrys [13], which consists of only the molecular diffusion term, would not wholly mimic the obtained high recovery rates in porous media, which means there is a need for more investigation on the other secondary mechanisms including the convective dispersion to be linked into the mass transfer mechanism to reflects the high obtained recovery rates from experiments. However, Das [21] tried to adjust the previous model of Butler and Mokrys [13] by introducing the apparent diffusion coefficient concept in porous media by integrating the intrinsic molecular diffusivity of solvent in bitumen D_o , porosity of the porous media ϕ , and cementation factor Ω , with the following equation:

$$D_p = D_o\phi^\Omega \quad (8)$$

When introducing those values in equation (6), the final flow rate can again be written as:

$$q = 2L\sqrt{2kg\phi^\Omega\Delta S_o N_s h} \quad (9)$$

Das and Butler [25] conducted experiments in sand packs by using Peace River and Athabasca heavy crude oils with butane as a solvent. Upon the results of the experiment flow rates of diluted oil, they again noticed that the obtained flow rates differed from those predicted by their introduced model in equation (9). It was then necessary for them to conduct a history match between the experimental results and the model and finally realized the obtained effective diffusivity D_{eff} is three to ten times more than theoretical molecular diffusivity D_s . Table 3 displays their obtained D_{eff} to D ratios included the one noticed by Dunn et al. [28].

Table 3
Comparison between History Matched Coefficients of Diffusivity and Theoretical Known Molecular Diffusivity from Literature [9].

Investigator	Solvent-Solute system	Physical Model used	D_{eff}/D
Dunn et al. [28]	CO_2 + Athabasca bitumen with water	Sand-Packed	460
	CO_2 + Athabasca Bitumen without water	Sand-Packed	65
Das and Butler [25]	Butane + Lloydminster Bitumen	Sand-Packed	3–5
	Butane + Peace River Bitumen	Sand-Packed	10

Etmnan et al. [30] conducted the experiment using a physical model with a permeability of 250 D while utilizing propane as a solvent to estimate the effective diffusivity coefficient, D_{eff} of propane in Athabasca bitumen using equation (9) by simply calculating a constant value N_s , using final values steady-state flow parameters at the end of the experiment and then utilizing it by using equation (7) to estimate the value, which is an excellent approach for evaluating a constant value of D_{eff} , in a particular porous media rather than relying on the literature values. Another observation made by Das and Butler [25] in their analysis is that despite an enhanced recovery rate in porous media by solvent, measured oil production rates behave to be proportionality to the square root of permeability, as theoretically depicted rates by equation (9) which is represented by the following expression.

$$\frac{q_1}{q_2} = \frac{L_1}{L_2} \sqrt{\frac{k_1 \phi_1^{\Omega_1} \Delta S_{o1}}{k_2 \phi_2^{\Omega_2} \Delta S_{o2}}} = \sqrt{\frac{k_1 \phi_1^{\Omega_1} \Delta S_{o1}}{k_2 \phi_2^{\Omega_2} \Delta S_{o2}}} \quad (10)$$

Lim et al. [50] assigned the values of an effective diffusivity to two up to three orders of magnitude greater than the literature molecular diffusivity to history match their experimental results in sand packs. They concluded that the noticeable increase in the diffusivity mechanism is not clearly defined. Still, they also point out that physical dispersion is the most considerable phenomenon for the cause of additional enhanced mass transfer in porous media. Also, Abukhalifeh et al. [1] stipulated that in VAPEX systems, the injected solvent vapours, usually at pressures close to the dew point, are responsible for the viscosity reduction of the native heavy oil/bitumen. While the diluted oil flows to the lower horizontal well under the action of gravity, the most believed drive mechanism is dispersion, which means the combination of molecular diffusion of the solvent into the heavy oil and its convection dispersion under the action of gravity after viscosity reduction which is mainly driven by the concentration gradient, and capillary action. Gravity and surface renewal also stimulate diluted oil mobility and its convection effect [25]. Usually, researchers had to use dispersion coefficients that are up to four orders of magnitudes higher than the molecular diffusion coefficients to match the actual production rates from experiments [29]. They were based on the fact solvent dispersion is the main reason for the high oil production rates in porous media compared with the one predicted by the oldest model, which doesn't include dispersion coefficients [1]. Al-Hadhrami et al. [2] applied the integration of experiments, an analytical model formulated by Butler and Mokrys [13], and numerical methodologies to study the VAPEX process. The flow rates obtained from the glass bead packs porous media experiments were then compared with the analytical model estimated by Butler and Mokrys [13], equation (6), where it was observed that the rate calculated by the analytical model was smaller even with the inclusion of a convective dispersion scenario. The dependency of the oil flow rate on the permeability's square root was also noticed, as reported by Das and Butler [25]. Therefore, Al-Hadhrami et al. [2] recommended that equation (6) did not precisely describe all the physical processes of the VAPEX; hence numerical simulation studies were much more encouraged due to at least closely matched flow rate results obtained numerically when compared with the experiments results.

This subject of the dispersion in the recovery rate equation/model is of significant importance, as already discussed, to be incorporated with the traditionally used diffusion process in the models since the economic accountability of the field project is directly affected/controlled by the speed of the recovery. But also, other governing factors need to be understood in detail and try to track other contributing mechanisms in a given VAPEX process rather than only relying on bigger values of diffusivity coefficients for matching the experimental and model results, which might end up with unrealistic conditions/processes phenomena, even though the incorporation of these mechanisms is a complex task as stated by Boustani and Maini [9].

2.3.2. Further developed analytical models of the VAPEX process

The subsequently analytically developed flow equation models for the VAPEX process were based on analyzing the shape of solvent chamber growth. Four forms were analyzed: linear, circular, parabolic, and exponential. The experimental VAPEX results of the previous works then validated the formed models. The following were the recently developed analytical models available in the literature.

Moghadam et al. [62] developed a mathematical model to predict the accumulative oil production data for different times. The transition zone thickness between the untouched heavy oil/bitumen and the solvent chamber with two straight line boundaries was assumed to not change with time, where it is then used further as an adjustable parameter to match the model results and the experiment results. The transition zone thickness variation at different data times was within 15 % relative average errors of the five VAPEX experimental observed thicknesses. Upon further analysis, Moghadam et al. [62] recommended that the transition zone thickness increase as the VAPEX model's permeability decreases. Moreover, the developed model predicted horizontal spreading and falling velocities, where they both dropped as time passed. Equation (11) shows the accumulative oil production during the solvent chamber spreading time, and equation (12) shows an equation for the solvent chamber boundaries falling period. The scenarios are shown in Fig. 5 [62].

$$Q_{cs} = h^2 d \phi \Delta S_o \cot \theta \quad (11)$$

$$Q_{cf} = h^2 w d \phi \Delta S_o (2 - \cot \theta, \tan \theta) \quad (12)$$

Where d = Transition zone layer thickness

ΔS_o = Change of heavy oil saturation in the solvent-swept zone

Lin et al. [52] developed an analytical model by considering the shape of the solvent chamber to be circular. The model was divided into three different stages of diluted oil production, which is chamber rising, spreading, and falling periods, as shown in equations (13), (14), and (15), respectively, with the anticipated scenario shown in Fig. 6. The transition zone thicknesses between dead (untouched) heavy oil and vapour solvent were used as the adjustable parameter between the validating experimental VAPEX results and the model outcomes results for those stages. The thickness during the rising phase was higher than in the remaining steps. However, the thickness was also recognized to increase as the values of the physical model's permeability decreased, as Moghadam et al. [62] reported. Lin et al. [52] continued to clarify that the different simulated oil rates used in different stages are more representative of the VAPEX process rather than of the single constant oil production rate estimated by the original model developed by Butler and Mokrys [13] under only the solvent chamber spreading phase. Therefore, Lin et al. [52] foreshadowed that this newly estimated model might be an alternative tool for simulating VAPEX processes in future heavy oil recovery projects.

$$Q_r = \frac{\pi}{4} \Delta S_o \phi d H^2 \quad (13)$$

$$Q(t) = \Delta S_o \phi d H^2 \left(\frac{(\pi - \theta) + \sin \theta \cos \theta}{(1 + \cos \theta)^2} \right) \quad (14)$$

$$Q(t) = \Delta S_o \phi d w^2 \left[\frac{(\pi - \theta)}{4 \sin^2 \theta} + \frac{H}{w} - \frac{2 + \cos \theta}{4 \sin \theta} \right] \quad (15)$$

Ma et al. [56] reveal that the previously developed models were based on the linear or circular shape of the solvent vapor chamber, as reported by Lin et al. [52]; Moghadam et al. [62], but in most of the laboratory tests of the VAPEX, the shapes were more closely resembled parabolic shape as stated by Ma et al. [56], due to this Ma et al. [56] developed analytical model based on the parabolic shape whether in concave or convex. In their experiment, each observed solvent chamber

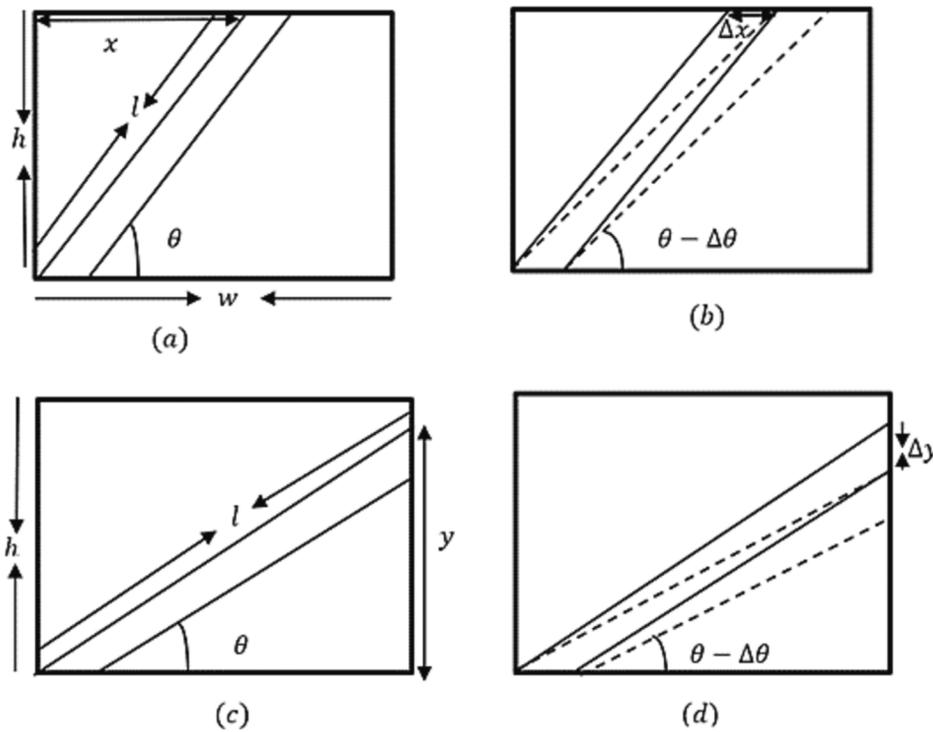


Fig. 5. (a) Position of the Transition Zone at Time t for the Case of Solvent Chamber Spreading Period, for Linear model (b) Shifted Position at Time $t + \Delta t$ for the Solvent Chamber Spreading Period, for Linear model (c) Position of the Transition Zone at Time t for the Case of Solvent Chamber Falling Period for Linear model and (d) Shifted Position at Time $t + \Delta t$ for the Solvent Chamber Falling Period for Linear model [29].

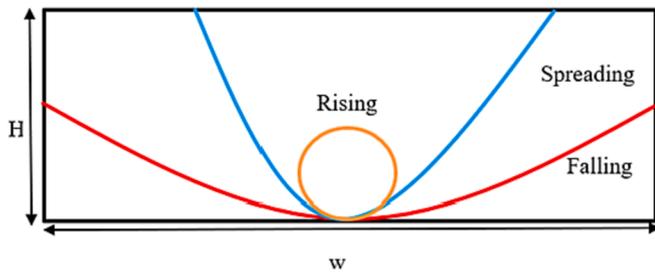


Fig. 6. Circular Solvent Chamber Evaluation in Three Stages: Rising, Spreading, and Falling [52].

picture/image is digitized at different times for the solvent chamber shape analysis by studying the abrupt change of the egrey level of each pixel. The methodology used by Ma et al. [56] was to compare the discrepancy between the digitized solvent chamber and the predicted model solvent chamber by adjusting the transition zone thickness. Compared with the previously developed models, linear and circular ones, the parabolic model by Ma et al. [56] seemed to fit the experimental VAPEX results better. The transition zone was again defined as a constant value that does not change with time, as defined by Lin et al. [52]; Moghadam et al. [62]. The transition zone thickness variation at different data times was within 13.1 % relative average errors of the five VAPEX experimental observed thicknesses. However, Ma et al. [56] assumed the initial oil saturation in the transition zone is reduced to residual oil saturation once the transition zone takes part as solvent chamber growth, which requires further studies to investigate such an assumption. Moreover, the model was based on estimating the accumulative diluted oil production by considering only the solvent spreading phase/stage, as shown in equation (16), with its scenario displayed in Fig. 7.

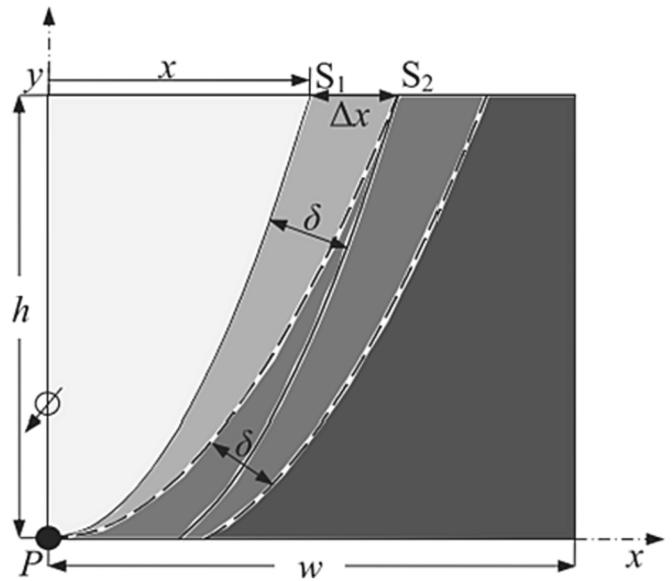


Fig. 7. VAPEX Transition Zone Transformation Scenario under Parabolic Solvent Chamber Evolution [56].

$$Q_o(t) = \frac{4}{3} h \sqrt{\frac{h}{a}} \Delta S_o \phi \delta \tag{16}$$

Cheperli et al. [18] derived the recent model based on the exponential function to define the solvent chamber evolution for the spreading and falling phases/stages by tuning the exponential function parameter and the transition zone thickness to match the literature VAPEX experimental results. The relative average errors obtained during the analysis for the four experiments were 7.73 % for the estimated cumulative produced oil and 5.12 % for the transition zone thickness,

which indicates the model is more precisely compared with the linear and parabolic model that had an error of 15 % and 13.1 % in case of transition zone thickness estimation respectively. Furthermore, the model predicts the oil production rate, and the expected solvent chamber shapes are well-digitized experimental obtained solvent chamber shapes. The scenario for the VAPEX process under the spreading case is presented in Fig. 8 for the concave and convex propagation cases, and the corresponding models are expressed in equations (17) through (19).

$$Q_o(t) = 2 \left(\frac{(H+a) \times (\ln(H+a) - \ln a) - H}{n} \right) \varnothing(S_{oi} - S_{or})d \quad (17)$$

$$Q_o(t) = 2 \left(\frac{(a-H) \times (\ln(a-H) - \ln a) + H}{n} \right) \varnothing(S_{oi} - S_{or})d \quad (18)$$

$$q_o(t) = \frac{d(Q_o(t))}{dt} \quad (19)$$

However, Cheperli et al. [18] developed the falling stage models for the accumulative diluted oil production rate for a concave case and convex case and corresponding flow rate model as given in equations (20), (21), and (22), respectively. The process scenarios are elaborated in Fig. 9.

$$Q_o(t) = 2 \left(\frac{HWn + aWn - ae^{Wn} + a}{n} \right) \varnothing(S_{oi} - S_{or})d \quad (20)$$

$$Q_o(t) = 2 \left(\frac{HWn - aWn - ae^{Wn} + a}{n} \right) \varnothing(S_{oi} - S_{or})d \quad (21)$$

$$q_{oi} = \frac{d(Q_o(t))}{dt} \quad (22)$$

The explained developed models were based on the assumption that the thicknesses of the transition zones were the main adjustable parameter to match the experimental VAPEX results. However, James et al. [40] stated that the physics of the thickness of that zone is not precisely known and is estimated to be on the order of small pore deep scale during the VAPEX with some minor variation, which implies that it's a solvent-heavy oil diffusivity behaviour dependency; hence further studies are more emphasized to clear doubts on the assumption.

2.3.3. Other possible heavy oil/bitumen recovery drive contributors during VAPEX process

The capillary counter flow of solvent and heavy oil in the mixing chamber zone is one of the significant factors stimulating the process of mass transfer in the VAPEX process, though there are other possible heavy oil/bitumen recovery governing mechanisms depending on solvent-heavy oil/bitumen-rocks interaction apart from physical

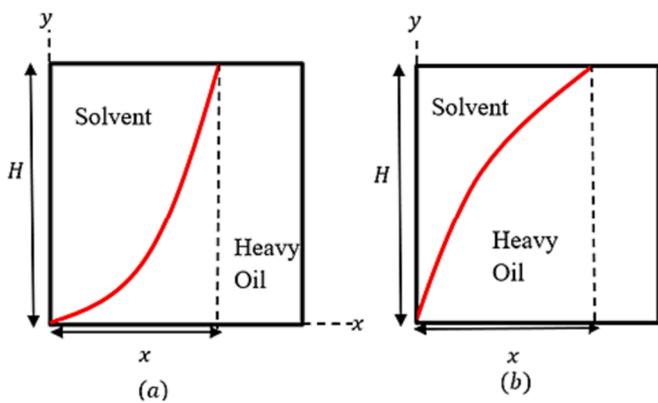


Fig. 8. (a) Transition Zone for the Concave Exponential VAPEX Process during Spreading Stage, (b) Transition Zone for the Convex Exponential VAPEX Process during Spreading Stage [18].

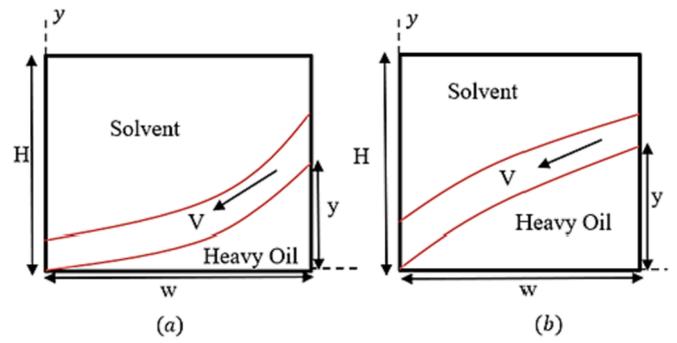


Fig. 9. (a) Transition Zone for the Concave Exponential VAPEX Process during Falling Stage, (b) Transition Zone for the Convex Exponential VAPEX Process during Falling Stage [18].

dispersion, these include; enhanced surface renewal by capillary imbibition, improved interfacial contact, enhancement during the rising of the solvent chamber, development of transient mass transfer across the interface, increased solubility due to solvent vapour condensation in the fine capillaries [9].

2.3.3.1. Capillary effect on VAPEX process. Rostami et al. [74] documented that, in addition to previous authors, VAPEX can be studied by further tracking the balance of capillary forces, viscous and gravity forces. Capillarity forces are usually raised in the actual field pore scales where permeabilities are smaller, millidarcy orders of magnitude compared with the presented permeabilities in the most published literature, which are in Darcie's orders of magnitude of the VAPEX process. Rostami et al. [74] revealed that using taller grid blocks in the simulation might mask the impact of capillarity forces compared with short grid blocks.

Furthermore, the base case simulation with small capillary pressures resulted in higher cumulative oil production compared with the other cases, which are the first case had capillary pressures of 10 times more than the base case, and the second case, where the capillary pressures are 100 times more than the base case capillary pressures [74]. To boost oil production, Rostami et al. [74] also noticed that the solvent/propane injection rate at the production end grid block needs to be increased, that is to say, to overcome the capillary forces by increasing the capillary number, as shown in Fig. 10. Rostami et al. [74] recognized the shape of

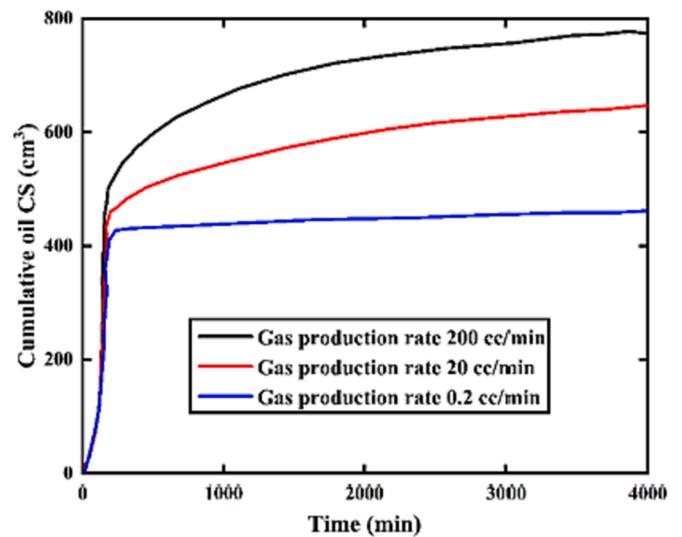


Fig. 10. Cumulative Oil Production after Increasing the Propane Rate at the Production Grid End for the Case Capillary Pressures was Multiplied by 100 [74].

the vapour chamber with the inclusion of capillary forces growth resembled a mushroom, which is more representative of VAPEX phenomena compared with very minimum capillaries force (base case) where the formed shape is vertical (piston-like displacement).

Tuhinuzzaman [84] also studied the impact of capillary pressure on the VAPEX performance. Kerosene was used to dilute the originated heavier oil from the Swimming field of Lloydminster in the Alberta-Saskatchewan area with an original viscosity of 100,000 cp to generate four different oil samples where experiments were performed to construct the capillary pressure curves using lighter oil samples with viscosities of 4 cp and 16 cp respectively and relative permeability curves using heavier oil samples with viscosities of 5,800 cp and 14,400 cp respectively. Heavier oil samples were also used to conduct a laboratory-scale VAPEX process with butane as a solvent.

Tuhinuzzaman [84] proceeds with numerical simulation using the CMG WINPROP section, where two variable oil composition models were created by turning the equation of state inside the simulator to resemble the oil samples used for the VAPEX laboratory experiment. After that, all necessary data were introduced into CMG GEM to simulate the laboratory scale VAPEX performance. Two analyses were done in the simulation study; the first was without turning the capillary pressure curve, and the second was by tuning the curves. Upon the results, the following were discovered:

- The significant contribution of capillary pressures on the VAPEX is the vapour chamber shaping. When no capillary pressure data is in the simulator, the chamber grows vertically with weak sideways percolating. While introducing the capillary pressure data, the vapour chamber grows in a mushroom shape, as Rostami et al. [74] reported, which is the more acceptable shape for the heavier oil sample used in the experiment, even from VAPEX phenomena theories.
- The effect of capillary pressures extends the solvent breakthrough. After the solvent breakthrough, capillarity increases the drainage rate by prolonging the effective solvent diffusion area. Also, the simulation depicted that fitting the capillary pressure data predicts higher oil production rates that approach the experimental results for the oil sample with a viscosity of 5,800 Cp.

2.3.3.2. Interfacial tension impact on VAPEX process. Rostami et al. [74] studied the effect of the inclusion of interfacial tension (IFT) change on relative permeability curves for propane vapour-heavy oil system since, for the VAPEX system, zero IFT doesn't exist because the process is not purely miscible; it's a solubility phenomenon, meaning that not a completely miscibility process. Therefore, Rostami et al. [74] clarified that the relative permeability would be duplicated by including the IFT reduction due to increasing solvent production rate with simple interpolation of the old relative permeability curve, as shown in Fig. 11. Furthermore, [74] noticed a cumulative oil production of 880 cm³ after injection of cumulative propane of 1.7 × 10⁴ cm³ with insertion of relative permeability change in the reservoir simulation model due to interfacial tension impact from Fig. 11, compared with cumulative oil production of 670 cm³ after cumulative injection of 1.1 × 10⁴ cm³ propane without interfacial tension effect (base case) in the simulation.

Xu [93] analyzed the influence of interfacial tension (IFT) on the performance of the VAPEX too. Xu [93] performed laboratory measurements of interfacial tension for various mixtures of solvent (binary systems)-heavy oil systems. Propane, n-butane, and carbon dioxide (CO₂) were the solvents used. The solvent-heavy oil mixtures of propane and carbon dioxide, n-butane, and carbon dioxide were generated by varying gas compositions. Upon analysis, it was found that interfacial tension between solvent schemes and heavy oil is inversely proportion to the applied system pressures. The applied pressure for the whole plan was kept closer to the dew points of the propane and n-butane solvents. The results for the interfacial tension variations with systems pressures

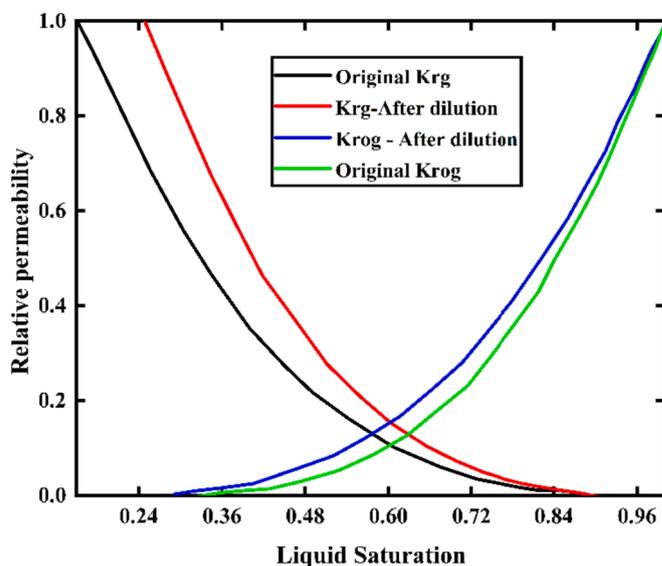


Fig. 11. Propane-Oil Relative Permeability Shifting after Solvent/Heavy Oil Surface Tension Reduction [74].

for the case of a binary mixture of propane and carbon dioxide are presented in Fig. 12. Xu [93] also observed the same ITF and pressure behaviour trend for the case of n-butane and carbon dioxide binary mixture solvents.

Xu [93] continued to develop two linear regression correlations using the least-square method for the binary systems using the laboratory data and succeeded in obtaining the following expressions for interfacial tension as a function of system pressures and hydrocarbons component mole fraction for the binary propane-carbon dioxide mixture and binary n-butane-carbon dioxide mixture respectively.

$$\sigma_{c_3H_8} = -0.0009pn + 0.0063p - 0.0089n + 25.3924 \quad (23)$$

$$\sigma_{c_4H_{10}} = -0.0039pn_1 - 0.0593p - 0.0075n_1 + 30.7936 \quad (24)$$

Where,

p = System pressure

n = Mole fraction of propane

n_1 = Mole fraction of n-butane

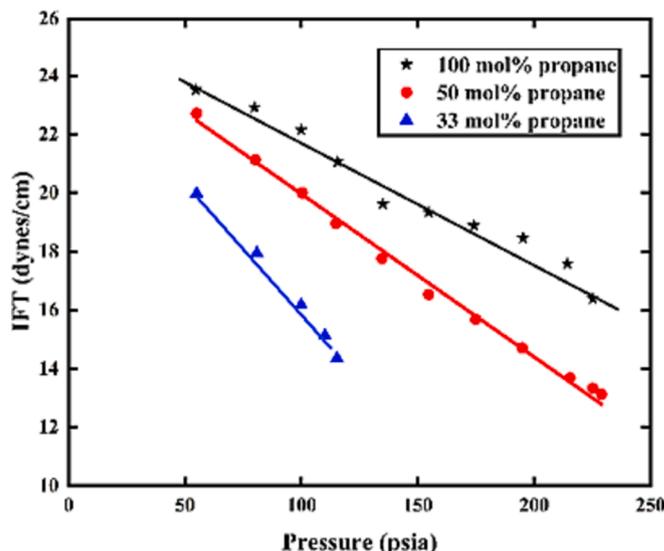


Fig. 12. IFT as a Function of the Binary Propane/CO₂ Gas Pressure [93].

Again, Xu [93] conducted two VAPEX experiments, VAPEX I and VAPEX II. The solvent injection pressure of only n-butane is the differentiator of the two VAPEX processes. For VAPEX I, the injection pressure used was 29.6 psi; for VAPEX II, the injection pressure was 27.2 psi.

The average production rate was higher in Run I compared with Run II. The oil production rate at the start was mainly viscous forces controlled. The rate seemed to increase while viscosity and IFT decreased and vice versa. At the end of the VAPEX process, the oil/gas interface at the lower limit of the solvent chamber was gradually approaching the producer bottom line, leading to the oil production rate declining and stopping when the oil gravity head was not sufficient enough to cause the oil to flow out of the porous media. Some production rates fluctuate due to minor pressure surges in the VAPEX model [93].

2.3.3.3. Enhancement during rising of the solvent chamber. The VAPEX oil recovery process can also be divided into three main stages of solvent vapour chamber growth: The first stage involves solvent vapour rising from the injection well and creating a vapour chamber. During this time, oil production is higher due to the counter-current phenomena of the extraction mechanism. Once the constructed vapour chamber hits the cap rock, it extends sideways/spreading, making this stage the more prolonged production phase stage, where the oil production rate is considered constant. Production continues until the boundaries of the reservoir are reached, which is the last stage leading the interface of the unproduced/ unextracted oil starts falling, where the gravity head is then reduced as well as the oil production rate [25,87]. Among the stages, the flow models, including an analytical model by Butler and Mokrys [13], were based on the estimation of oil flow rate based on the second stage and perhaps the last step since it seems quite complex to model the first stage.

Lin et al. [52] developed a model for estimated accumulative oil production during chamber rising using transition zone thickness as the adjustable parameter to match with the experimental VAPEX results, as shown in equation (13), while Nadriyan and Hosseini [65] formulated an analytical model that resembled the one developed by Dianatnasab et al. [26] to model the initial flow rates during VAPEX performance. The formulated model by Nadriyan and Hosseini [65] is expressed as follows:

$$q_b = \sqrt{2 \frac{Kkg \cdot \varnothing \cdot \Delta S_o \cdot D \cdot H}{v_o} \left(\frac{1}{nm+1} \right) - \left(\frac{c_o}{nm+n+1} \right)} \quad (25)$$

Where:

- K = Average system permeability
- k and m = Kinematic viscosity model correlating parameters
- v_o = Kinematic viscosity of the produced oil
- D and H = Solvent molecular diffusivity and system effective height, respectively

The corresponding formed dimension less flow rate of the equation is given as:

$$Q_b = \sqrt{2kxR_a \left(\frac{1}{nm+1} \right) - \left(\frac{c_o}{nm+n+1} \right)} \quad (26)$$

R_a , is the Rayleigh number, expressed as,

$$R_a = \frac{KgH}{\varnothing \Delta S_o v_{os} D} \quad (27)$$

Since equation (25) was based on the assumption of pseudo-steady-state flow, which might end with some little inaccurate results, then [65] re-expressed equation (25) as

$$q_b = x_1 \times Ra^{x_2} \left(\left(\frac{1}{nm+1} \right) - \left(\frac{c_o}{nm+n+1} \right) \right)^{x_3} \quad (28)$$

Nadriyan and Hosseini [65] used the VAPEX experimental/test results of the flow rate obtained by [62] using propane as a solvent to find the optimal values in equation (28) coefficients by minimizing an objective function as expressed in equation (29) and found the values of the optimal coefficient with their respective errors as displayed in Table 4.

$$E(x_1, x_2, x_3) = \frac{1}{t_n} \sum_{i=1}^n \left[\frac{q_c(t_i) - q_m(t_i)}{q_m(t_i)} \right]^2 (t_i - t_{i-1}) \quad (29)$$

The developed model was inspected and seen to provide better results when the ratio of width to height of the reservoir was close to 1, and the wells/reservoir length ratio to effective drainage height was less or equal to 4. Furthermore, the model was derived based on a steady-state flow regime, which might not be an actual representable flow regime [65].

There are no recently recognized analytical nor numerical mathematical formulations of the last two governing mechanisms, which are the development of transient mass transfer across the interface of solvent-heavy oil/bitumen and increased solubility due to solvent vapour condensation in the fine capillaries in the recent literature, which demands the need/room for further analysis/investigation of these subjects in the future VAPEX researches.

2.3.4. Developed models that combine the possible driving mechanisms

Lowman [53] developed the first oil flow rate predictive model that captured most of the possible physical processes and tried to predict the VAPEX experiments results with the model. The following were the assumptions made during model development:

- Rigidity, non-reacting, and unconsolidated states for the solid phase porous media
- The temperature in the system is constant
- The liquid phase is incompressible
- The model was developed based on the butane solvent because butane solvent experiments are abundantly available
- The liquid phase is composed of a binary mixture of bitumen and butane
- The gas phase is composed of only butane components
- The reference pressure for the gas phase was 0 psi
- The gas phase is assumed to be pure butane with infinite mobility
- The domain used for the model construction is a two-dimensional cartesian coordinate system (x, z) where z is the unit vector in the opposite direction of the force of gravity, measured up from the reference height z = 0

The following were the steps conducted by [53] to come up with the model:

- ① Conservation of mass for the liquid phase and each of the components in the liquid phase and gas phase, ending up with the following two expressions:

$$\varnothing \frac{\partial}{\partial t} (S_l) + \nabla \cdot (v_l) = J_s \quad (30)$$

$$\varnothing \frac{\partial}{\partial t} (S_l \omega_s) + \nabla \cdot (\omega_s v_l - \varnothing S_l D \nabla \omega_s) = J_s \quad (31)$$

Table 4
The Obtained Coefficients of the Developed Analytical Model by [65].

	Test 1	Test 2	Test 3	Test 4	Test 5	Average Value
x_1	2.45	2.45	2.45	2.45	2.45	2.45
x_2	0.62	0.54	0.65	0.63	0.63	0.63
x_3	0.96	0.99	0.95	0.96	0.96	0.96
E	18 %	23 %	18 %	12 %	12 %	15 %

Introduce Darcy's velocity term; in equations (30) and (31), the final equations become,

$$\phi \frac{\partial}{\partial t} (S_l(\psi, \omega_s)) + \nabla \cdot \left(-\frac{kk_r(\psi, \omega_s)\rho_l g}{\mu(\omega_s)} \nabla(\psi + z) \right) = J_s(\psi, \omega_s) \quad (32)$$

$$\phi \frac{\partial}{\partial t} (S_l(\psi, \omega_s)\omega_s) + \nabla \cdot \left(\omega_s \left(-\frac{kk_r(\psi, \omega_s)\rho_l g}{\mu(\omega_s)} \nabla(\psi + z) \right) - \phi S_l(\psi, \omega_s) D(\psi, \omega_s) \nabla \omega_s \right) = J_s(\psi, \omega_s) \quad (33)$$

Where,

- S_l = Saturation of the diluted oil in the mixing zone
- ω_s = Mass fraction of solvent (butane)

The equations above are the introduced empirical correlations that can be solved numerically.

The main unknowns in the equations which need to be solved numerically after a given time step are S_l and ω_s which are again expressed by the equation:

$$S_l = \frac{S_{sat} - S_r}{(1 + (\alpha + \psi)^n)^{1-\frac{1}{n}}} + S_r \quad (34)$$

Where;

- S_{sat} = Fully saturated domain
- S_r = Residual saturation
- α = Scaling parameter that is used to change the capillary pressure curve based on interfacial tension and relative permeability to a known capillary pressure curve
- n = Fitting parameter explored by matching the capillary pressure curve to a known curve relative permeability in the equation is expressed as:

$$k_r = S_{eff}^{\frac{1}{n}} \left(1 - \left(1 - S_{eff}^{\frac{1}{n}} \right)^{1-\frac{1}{n}} \right)^2 \quad (35)$$

$$S_{eff} = \left(\frac{1}{1 + (\alpha\psi)^n} \right)^{1-\frac{1}{n}} \quad (36)$$

© Scaling of capillary pressure curves (water scaled)

If the J function is utilized for scaling the drainage capillary pressure data ($p_{cv}S_l$) of mono-size packings, then capillary pressure characterization due to the interfacial tension between the bitumen-butane mixture, permeability, and porosity of the domain/matrix sand can be presented by Leverett's equation (37)

$$\frac{p_{c1}}{p_{c2}} = \frac{\gamma_1}{\gamma_2} \sqrt{\frac{k_2}{k_1}} \quad (37)$$

Equation (37) can further be expressed as:

$$\frac{\alpha_2}{\alpha_1} = \frac{\gamma_1}{\gamma_2} \sqrt{\frac{k_2}{k_1}} \quad (38)$$

The interfacial tension between the bitumen and butane mixture was defined by the equation below:

$$\gamma_o = 6.39e^{-13.32\omega_s} + 4.20e^{-10.84\omega_s} + 12.15e^{-2.51\omega_s} + 11.52 \quad (39)$$

Molecular diffusion and mechanical dispersion of the solvent into the heavy oil/bitumen effect, as indicated by D in the conservation of mass equation, is related to the equation below,

$$D = \begin{bmatrix} \frac{\sigma_{long}u_x^2 + \sigma_{tran}u_z^2}{\sqrt{u_x^2 + u_z^2}} & \frac{(\sigma_{tran} - \sigma_{long})u_xu_z}{\sqrt{u_x^2 + u_z^2}} \\ \frac{(\sigma_{tran} - \sigma_{long})u_xu_z}{\sqrt{u_x^2 + u_z^2}} & \frac{\sigma_{long}u_x^2 + \sigma_{tran}u_z^2}{\sqrt{u_x^2 + u_z^2}} \end{bmatrix} + D_m m^2/s \quad (40)$$

Where,
Molecular diffusion,

$$D_m = 4.78 \times 10^{-10} \omega_s + 4.91 \times 10^{-10} \quad (41)$$

The numerical method used to solve the VAPEX model described by the equations (32) through (41) was based on Python programming languages, specifically with the Chebyshev Collocation methodology and the Network-Krylov method. The bitumen viscosity and reservoir permeability used in the model were 23.2 kg/ms and 1,123 D respectively. Some of the yielded model results, including the oil production rate and cumulative oil simulated according to the VAPEX experiment conditions were presented in Fig. 13. The model showed a good agreement with the VAPEX experiment.

2.4. Numerical simulation analysis of VAPEX processes

A simulation is one of the tools used to analyze reservoir performance [32]. As long as VAPEX involves vapour injection into the reservoir, it is necessary to search for alternatives/mechanisms to incorporate its role in the reservoir simulation models. VAPEX processes are commonly performed numerically by composition analysis of the hydrocarbon components in the oil and gas phases. The principle of compositional simulation is that the composition of the liquid or gas phases varies adiabatically; therefore, different properties of the phases will be calculated at different times due to pressure changes in variable locations of the reservoir [84]. Commercial numerical simulation software, which has specifically taken a big part in VAPEX simulation analysis, is CMG STAR. The developed compositional model flow equations included asphaltene precipitate flow impacts were derived based on the following assumptions [66].

- Fluid mixing that enhances the solvent chamber growth is governed by molecular diffusion and convective dispersion, but convective dispersion is the dominant mechanism.

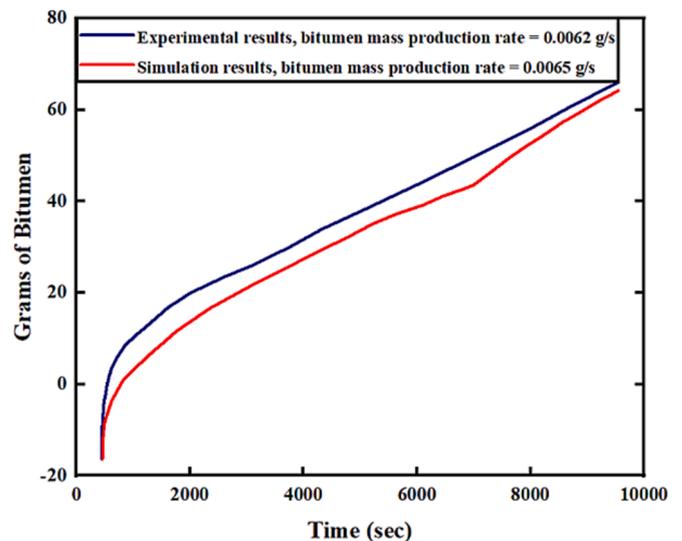


Fig. 13. Comparison of Experimental VAPEX Bitumen Production and Simulated VAPEX Bitumen Production [53].

- The asphaltene precipitate is modelled as a pure solids material that flows in the suspension of the oil phase or solid deposits onto the rock surfaces.

The following equation describes the component's transport behaviour modelled in the simulator, which is the finite-difference equation for the flow of components in the oil and vapour phases together with suspended asphaltene components in oil:

$$\Delta T_o^m (y_{io} + y_{isf})^m (\Delta p^{n+1} - \gamma_o^m \Delta d) + \Delta T_g^m y_{ig}^m (\Delta p^{n+1} + \Delta p_{cog}^m - \gamma_g^m \Delta d) + \sum_{k=0,g} \Delta \frac{A}{\Delta t} (\rho_k D_{ik})^m \Delta y_{ik}^{n+1} + q_i^{n+1} - \frac{V}{\Delta t} (N_i^{n+1} - N_i^n) = 0, i = 1, \dots, n_c \quad (42)$$

Where,

- A = Gridlock cross-sectional area (m²)
- d = Depth (m)
- D_{ik} = Total dispersion coefficients for component i , in the phase k ($k = o, g$) (m²/s)
- g = gravity acceleration (m/s²)
- N_i = Moles of component i per grid block volume
- p = Oil phase pressure (kPa)
- p_{cog} = Oil-gas capillary pressure (kPa)
- T_k = Transmissibility of phase k , ($k = o, g$)
- y_{ik} = Mole fraction of component i , in phase k ($k = o, g$)
- y_{isf} = Mole fraction of suspended solid in an oil phase
- Δl = Grid block distance (m)
- $\gamma_k = \hat{\rho}_k g$, the gradient of phase k ($k = o, g$)
- $\hat{\rho}_k$ = mass density of phase k ($k = o, g$) (kg/m³)

y_{isf} , corresponds to the suspended solid flow together with the diluted oil. Therefore, it refers to asphaltene components, n_c , only in the heavy oil/bitumen components. Equation (43) below explains the insertion principles of this parameter in equation (42)

$$y_{isf} = \begin{cases} 0, & \text{if } i \neq n_c \\ N_{sf}/N_o, & \text{if } i = n_c \end{cases} \quad (43)$$

Where, N_{sf} , are the moles of suspended solids and N_o , is the moles of the oil phase.

The value of transmissibility in equation (42) is expressed as:

$$T_k = \left(\frac{kA}{\Delta l} \right) \left(\frac{k_{rk} \rho_k}{\mu_k} \right) \quad (44)$$

Where,

- k = Absolute permeability of the grid block (mD)
- k_{rk} = Phase relative permeability in the grid block (fraction)
- ρ_k = Phase molar density in the given grid block (mol/m³)
- μ_k = Phase viscosity in the given grid block (cp)

The value of diffusivity coefficients in equation (42) includes both diffusion and convective dispersion coefficients. Pressure and fluid saturations (component compositions in each phase) can be solved iterative for each grid block until the solution of equation (42) is converged. The methods for solving pressures and component compositions are categorized as follows:

- Implicit Pressure, Explicit Composition, and Saturations (IMPECS) where the subscript n reflects the values of the parameters last time step and $n + 1$, the values at future time step and m is equal to n .
- Full Implicit (FI) where saturations (compositions) and pressures are both computed implicitly. The value of m will be equal to $n + 1$, too.

Modelling asphaltene usually requires dividing higher molecular components into two groups. For example, C_{31+} can split into C_{31A+} ,

which represents a non-precipitating component, and C_{31B+} , which means the precipitating components. The two components will still have similar critical and acentric factors but variable interaction coefficient properties with the light components. These precipitating components interact more with the light hydrocarbons, usually, solvents applied for the VAPEX process, leading to precipitate formation as the concentration of the light hydrocarbons increases in solution due to significant incompatibility between the components and solvents. The solid/precipitate portion insertion in equation (42) can be done through phase fugacity principles as expressed in equations (45) and (46) below. Phases fugacity complete calculations can be referred to [69].

$$\ln f_{io} = \ln f_{ig}, i = 1, \dots, n_c \quad (45)$$

$$\ln n_{c,o} = \ln f_s \quad (46)$$

Where,

- f_{io} = Fugacity of component i in the oil phase
- f_{ig} = Fugacity of component i in the gas phase
- f_s = Fugacity of solid phase
- n_c = Number of hydrocarbon components

Das [22] explored that conveying microscopic scenarios into macroscopic simulation models has several limitations, including using higher coefficients of diffusivity and dispersion to match the experimental flow rate. However, there are weaknesses in the observed thickness of the solvent-heavy oil/bitumen diffusion zone in the simulation model; it is usually thicker than the one captured from experiments and, hence, might end up with unrealistic coefficient values. Das [22] used the Dynamic Grid Refinement technique to improve process modelling by utilizing small grid blocks at the diffusion boundary layer. Upon results, it was concluded that the method improved the modelling of the values of diffusivity coefficients, and there was a good match between the experiments and simulations transition zone/ diffusion zone. Mohammadpoor and Torabi [63] conducted numerical simulation using CMG's STARSTM to identify critical parameters that affect the overall performance of the VAPEX technique focused mainly on wells configuration and rock permeability after a match of the twelve experimental results using two physical sand models, the larger one with $40 \times 47.5 \times 5$ cm³ dimensions and the smaller one with $20 \times 24.5 \times 5$ cm³ dimensions. Different solvents were employed in the study, which included propane, butane, propane/carbon dioxide mixture, propane/methane mixture, carbon dioxide, and methane. The experimental environments were simulated, and adequate history-matching results were attained after tuning diffusion coefficients and relative permeability curves. The twelve experiments were matched by CMG's STARSTM simulation software using packed Ottawa sand # 530 in the models. The viscosity of the heavy oil utilized was 5,650 cp, and their recovery performance analysis results are summarized in Table 5 and Table 6 for the large and small physical models, respectively.

From Tables 5 and 6, the following were the noted significant findings by Mohammadpoor and Torabi [63]:

- Propane shows the highest recovery factor compared with other solvents, which also agreed with the investigation done by Nghiem et al. [66], with a promising higher recovery factor of 75 % for both large and small models, respectively, and at an ultimate oil production rate of 13.2 cm³ /h. Butane is the second solvent to show a higher % recovery factor of 57 % for both models.
- Lower recovery factors for methane and carbon dioxide, due to the limitation on the operating pressures, seemed to be lower compared to their vapour pressures, leading to lower solubility, with the ultimate small recovery factors after injection of CO₂ in the small and large models of 30 % and 31 % respectively, while for the methane were 41 % and 39 % respectively. After mixing CO₂ with propane, there is a noted improvement in the oil recovery. This reveals that

Table 5
Analysis of the Oil Recovery Performance for the Large Physical Model [63].

Test	Solvent	ϕ /(%)	k/(D)	Injection Pressure/(kPa)	Recovery Factor/(%)	Oil Production Rate/(cm ³ /hr)	Viscosity/(mPa.s)	Density/(kg/m ³)
1	C ₃	43.1	9.12	700	75	30.00	469	938.17
2	C ₄	42.1	8.69	140	57	19.20	5520	970.11
3	C ₁	41.8	5.88	850	31	3.42	4910	961.80
4	CO ₂	42.6	6.70	850	26	1.68	3220	965.92
5	C ₃ /CO ₂	42.4	8.87	850	52	19.80	1160	944.46
6	C ₃ /C ₁	42.1	9.23	850	41	15.00	2080	961.10

Table 6
Analysis of the Oil Recovery Performance for the Small Physical Model [63].

Test	Solvent	ϕ /(%)	k/(D)	Injection Pressure/(kPa)	Recovery Factor/(%)	Oil Production Rate/(cm ³ /hr)	Viscosity/(mPa.s)	Density/(kg/m ³)
1	C ₃	42.2	8.78	700	75	13.20	999	853.50
2	C ₄	42.4	9.63	140	57	8.40	4730	969.28
3	C ₁	40.7	5.12	850	35	1.62	5010	962.88
4	CO ₂	42.1	6.11	850	28	0.72	2960	934.54
5	C ₃ /CO ₂	41.8	8.64	850	54	9.00	1480	954.48
6	C ₃ /C ₁	42.0	8.50	850	49	7.80	2380	963.10

CO₂ can save an added advantage of being a carrier gas in VAPEX processes to minimize solvent expenses.

- Higher drainage rates from the larger physical model compared with the smaller physical model, which depict that the recovery rate is directly proportional to the drainage height.

Mohammadpoor and Torabi [63] also sampled four different areas from the models to study asphaltenes and residual oil distributions from the models tested localized areas and found that for all the solvents, precipitations are in a more considerable amount close to the injection wells and at the oil/solvent interface for both models, again at a specific sampling area, a larger physical model shows slightly bigger value due to larger contact area between injection and production well in comparison with the smaller model and propane solvent was found to yield lowest residual oil saturation in all localized area for both physical models among other solvents which reflect better-swept efficiency by propane. However, all solvents show the lowest value of residual oil saturations for the localized area near the injection wells. Mohammadpoor and Torabi [63] again conducted numerical simulations to match twelve experimental results for both models and have an adequate match after tuning the coefficients of dispersion terms and relative permeability curves. However, the significant differences between experimental and simulation results were clearly observed in both experiments and simulations when solvent was first breakthrough. This scenario was much achieved for the propane solvent experiments and simulations, and the recognized reason is a sudden solvent entrance in the production well, resulting in a two-phase flow. The scenario was also noted by Rahnema et al. [72], Xu et al. [92] after a VAPEX simulation once the distance between production and injection well increases. Again, Xu et al. [92] explored that using finer grades might minimize the discrepancy, but it will take longer simulation time. Also, the issues of convergences and numerical instability difficulties will be associated with simulation runs.

Furthermore, Mohammadpoor and Torabi [63] used the matched CMG's STARSTM fluid properties to study the effect of the wells configurations, reservoir permeability, and grid thickness and came up with the following discoveries:

- The fifth wells configuration obtained the highest recovery due to the considerable distance from injection to the production well yielding maximum contact area between solvent and heavy oil, resulting in suitable mixing between solvent and heavy oil. The diluted oil is then easy to recover due to greater drainage height.

Furthermore, [63] noted that as the permeability of the model increased, the recovery factor also increased and it can be seen that small-thickness grid blocks gave better recovery performance with an average of 70 % for the grid block size of 1–4 cm and least recovery performance efficiency of 47 % for the grid block size of 8 cm.

Yazdani and Maini [95] discussed the issues of lab-scale VAPEX modelling by looking at some of the difficulties and challenges associated with the numerical solutions to resemble the physical processes. They achieved their study using a commercial composition simulator to match the lab-scale VAPEX data and concluded that it is still a challenging task to reflect the physical experimental processes with the use of current commercial simulators at the moment. The following are the findings they were reported from their study:

- The high permeability values used in laboratory experiments are usually associated with minimal pressure gradients, which are quite complex to accommodate by commercial numerical solvers, leading to significant numerical hurdles. Sometimes, the condition might be of less concern in the field-scale simulation. Experiments are usually conducted in the physical models packed with glass beads or sands with the average used permeability of 50–800 D, while the field permeabilities are in mD–10 D.
- The level of tuning viscosity, PVT data, and equation of states (EOR) per specific solvent-heavy oil system is high for the solvent-involving simulations, and this is because the diluted oil layer movement is crucially governed by those mentioned tuned parameters, the literature correlations and PVT/EOR models are associated with seriously unreliable justifications/conclusions. Therefore, it is highly recommended to adjust viscosity, PVT data, and equation of state and compare them with the experimental data to represent a specific solvent-heavy oil system for reliable results. Fig. 14 shows the tuned viscosity model, which is a Kendal model with a comparison with the laboratory data, which can then fit in the simulation model and will be reliable.
- Unrealistic diffusivity coefficients generally match the experimental data, relying on the fact that the absolute dominant mass transfer could be convective dispersion but would not likely occur in laboratory and field scale processes. Still, molecular diffusion should be considered the mass transfer mechanism, and more investigation for other factors is needed.
- Fine threshold grid sizes are recommended compared with the larger, thicker grid blocks since they adequately capture the physical processes involved in the thin drainage layer. Hence, a reliable

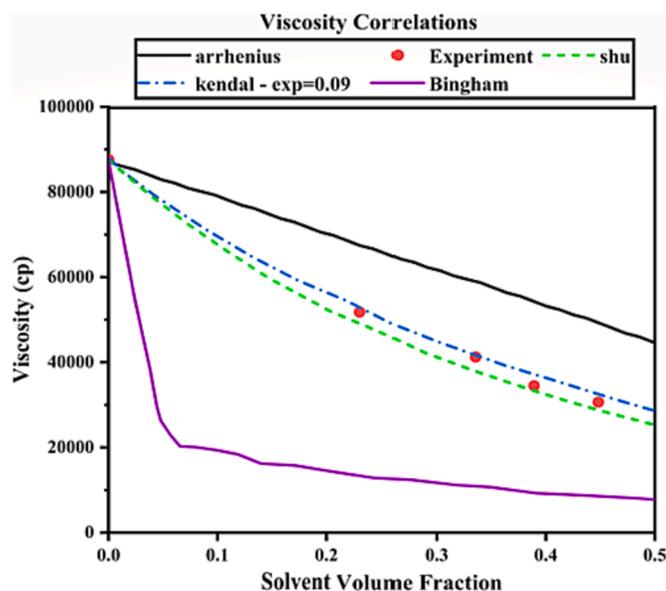


Fig. 14. Comparison of the Modeled and Measured Viscosities with Available Mixing Correlations [95].

picture is obtained in representing the drainage layer thickness of the physical VAPEX processes. However, there is a reasonable increase in simulation time and costs.

- Most represented pitfalls are not specific to a given simulator and are explored using finite difference methods as the solving technique. Then, more development and checking the applicability of other solution methods, including limited element/volume, is motivated to high grade the accuracy and reliability of the VAPEX simulations.

As discussed previously, the commercial simulation of VAPEX is based on a two-phase flow, which is diluted oil (liquid) and solvent vapour (gas), as given in equation (42). Very small grid blocks are recommended to capture the transition zone specifically representable of the diluted oil portion since the transition zone thickness is usually tiny, as reported by Yazdani and Maini [95]. Using very small grid blocks is time-consuming and not feasible for field-scale operations. Therefore, Nourozieh et al. [67] tried to develop a new three-phase model that involves heavy oil, diluted oil, and vapour (solvent) phases that could capture the transition zone. The simulation model can use reasonable grid block sizes to improve the unrealistic mixing of the original heavy and diluted oil in the transition zone within grid blocks. However, the proposed model was successful matched with the results of VAPEX experiments using small diffusion coefficients but faced challenges on equilibrium calculation and three phase relative permeability modelling knowledges.

2.5. Factors affecting VAPEX performance

Several factors might affect the recovery efficiency of the VAPEX process; among those, in this paper, only the main factors that will be highlighted and seen as the fundamental ones include solvent type, solvent injection pressure, solvent injection rate, oil viscosity, permeability of the porous media, distance between wells and wells configuration, interfacial tension and viscous fingering effect.

2.5.1. Solvent injection pressure

It is already assessed and recognized that the solubility of the solvent in heavy oil increased with the applied injection pressure, as shown in Fig. 15. Usually, to have an optimal performance of the VAPEX process, it is needed to inject solvent at a pressure close to its dew-point/vapor pressure at reservoir temperature to achieve maximum solubility of the solvents in heavy oil/bitumen and hence higher recovery efficiencies

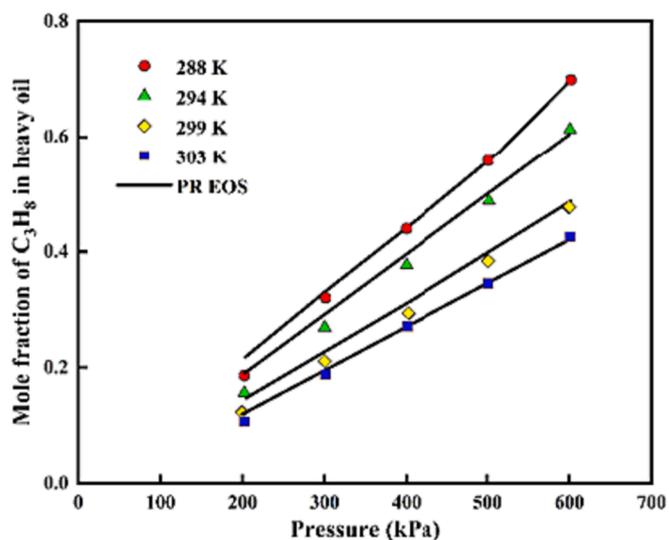


Fig. 15. Measured and Correlated Results for Solubility of Propane in Heavy Oil from Cactus Lake Area, Saskatchewan, Canada with a Viscosity of 724.15 mPa.s [61].

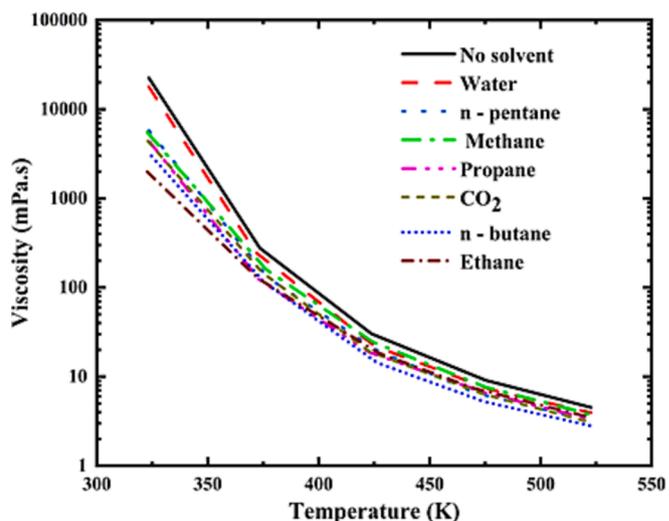


Fig. 16. Various Solvents Ability on Surmont Bitumen Viscosity Reduction at Variable Temperatures [17].

[25]. Again, the experimental results of Butler and Mokrys [12] confirmed that injection of the solvent near its dew point/vapour pressure resulted in a higher oil production rate. However, the highest viscosity reduction will yield asphaltene precipitates in the formations [35].

2.5.2. Solvent type and concentration vs. Heavy oil/Bitumen viscosity reduction

The viscosity of heavy oil is the function of temperature, as shown in Fig. 3. The higher the temperature for the same asphaltene components content, which are more likely responsible components for the viscous behaviour of heavy oil/bitumen, the lower the heavy oil/bitumen viscosity. Chen et al. [17] described the characteristics of various solvents on bitumen viscosity reduction at multiple temperatures and constant pressure of 4 MPa. Fig. 16 shows the ability of those solvents on Surmont bitumen viscosity reduction with the trend indicating that heavier hydrocarbon solvents have a more remarkable ability to reduce viscosity, and this is because of their higher value of solubility on heavy oil at same applied conditions as shown in Fig. 17.

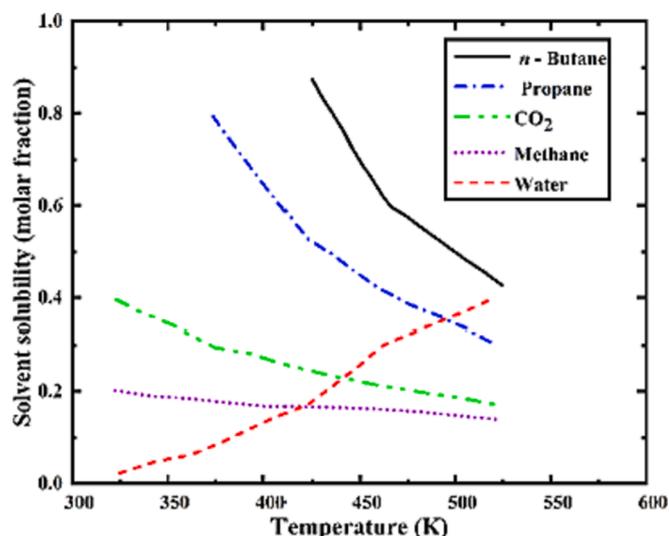


Fig. 17. Solubility of Different Solvents on Surmont Bitumen at Variable Temperatures [17].

Shu [79] represented the impact of San Ardo heavy oil viscosity reduction with a specific gravity of 0.98 at 37.7 °C after being mixed with various solvents where it was revealed that at one particular constant temperature, as the solvent concentration increases, the values of heavy oil viscosities decrease too. Then, it is imperative to have laboratory characterization of the heavy oil/bitumen and solvent viscosity reduction at different operating conditions in order to have the optimal solvent selection and operating parameters for heavy oil recovery. Estimating heavy oil viscosity reduction extents is an essential/crucial aspect in the petroleum industry practices involving crude oil viscosity reduction for the process performance evaluation and analysis. Alomair et al. [3] developed a model that predicts heavy oil viscosity reduction based on the effect of temperature and solvent dilution. Alomair et al. [3] first obtained the laboratory measurements of six heavy and extra heavy oil samples over a wide range of temperatures and used the existing temperature change model to validate the results, then including both effect of temperature and solvent concentration to develop a new model that accounts for the impact of both factors on viscosity reduction of heavy oil and extra oils, the developed model performed best on the heavy oil than extra heavy oil with an error of 18.9 % on viscosity reduction estimation for the extra heavy oil. This implies that viscosity reduction models based on specific solvents are vital components to characterize simulations and analytical model's which will be generally applied for a specific heavy oil/bitumen reservoir. Methodologies can be the same as stated by [3], but each field would need to have its model since heavy oil/bitumen resources usually differ in regions. Keyvani et al. [42] developed a binary mixture of solvent-heavy oil systems by tuning the Peng-Robinson equation of state (APR-EoS) with binary interaction coefficients (k_{ij}) and succeed to construct pressure-composition phase diagrams. The same approach could be used to build a phase pressure-composition diagram from the solvent mixtures system, for example, propane and carbon dioxide or propane and butane, and hence optimization of the VAPEX performance during the establishment of mixing solvent mole fraction ratio for a given reservoir operating pressure since the information of this subject in recently literature is limited.

2.5.3. Solvent injection rate, heavy oil/bitumen viscosity and reservoir permeability

Azin et al. [5] conducted a VAPEX simulation using the oil and rock properties of one of the Iranian heavy oil fields to study the impact of injection rate on the recovery of heavy oil based on viscosity value and the effect of formation permeability. The solvent used in the analysis

was a binary mixture of methane and pentane. For the injection rate, it was observed that as the injection rate increased for a given value of heavy oil viscosity, the recovery factor got larger, too, as shown in Fig. 18. For the case of heavy oil value viscosity, the lower the value, the higher the oil recovery, as shown in Fig. 19 and for the permeability value, it was noted that the higher the value of reservoir rock permeability, the higher the heavy oil recovery for all cases of values of oil viscosities as shown again in Fig. 20 the scenario is also reported from VAPEX simulation study conducted by [63].

Kok et al. [46] experimented on Turkish heavy oil using butane and propane as the solvents through the Hele-Shaw Cell. The three utilized injection rates for both solvents were 20, 40, and 80 ml/min, and upon results, it was observed that the heavy oil recovery factor increased with the solvent injection rate for both solvents. For the case of asphaltene precipitation, propane solvent was seen as the one that gave better results. Bayat et al. [7] conducted a CMG GEM simulation to analyze the mega field behaviour in contrast with most of the literature-conducted experiments and simulations, which were commonly based on micro and macro reservoir scale properties by examining the optimization injection rate utilizing solvents binary mixtures; the first batch was propane and methane, with propane mole fraction ranging from 5 – 50 %, and the second batch was butane and methane, with butane having a mole fraction ranging from 5 to 40 % because the use of pure solvents (propane and butane) according to the in-situ reservoir condition might end up with vapor condensation. Upon their first analysis, they noticed that porosity, vertical permeability and reservoir bulk volume size doesn't relate much to solvent injection rate performance to enhance oil recovery but injector well placement from the reservoir top and injection well length were found to have a linear relationship with injection rate. Bayat et al. [7] wanted to find an optimal injection rate by setting injection bottom hole pressure as the controlling constraint by assigning the value slightly higher than the average reservoir pressure, 21,092 kPa, while the average reservoir pressure was 20,747 kPa. This scenario was running for 25 years, and unfortunately, after three years, there was a noticeable significant considerable value of Gas-Oil-Ratio (GOR) due to a very early solvent breakthrough in the producer. Therefore, BHP well controlling constrain seemed not feasible; consequently, it was replaced by constant gas rate constraint (STG). This value was then recognized from the previous analysis where the BHP was used as a constraint by extracting the gas rate domain, minimum, and maximum, which were 425 and 1,982 m³/day.

To confirm the maximum value, i.e., 1,982 m³/day, Bayat et al. [7] used another rate higher than 1,982 m³/day and observed a significantly faster connection between the producer and injector before sufficiently

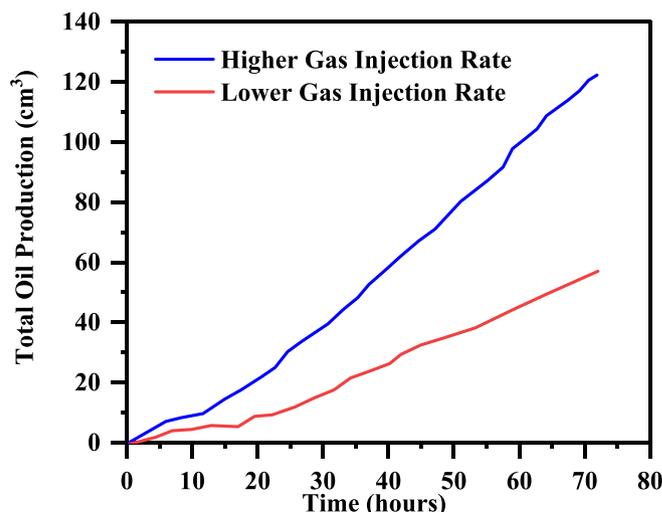


Fig. 18. Effect of Solvent Gas Injection Rate on Cumulative Oil Production [5].

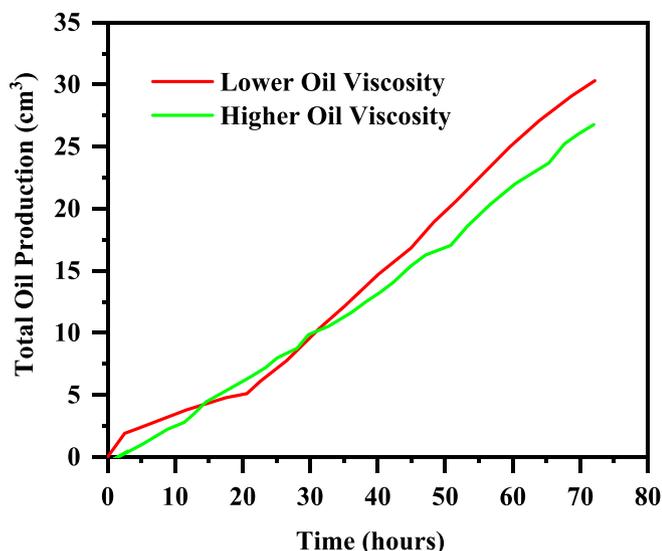


Fig. 19. Effect of Heavy Oil Viscosity on Cumulative Oil Recovery [5].

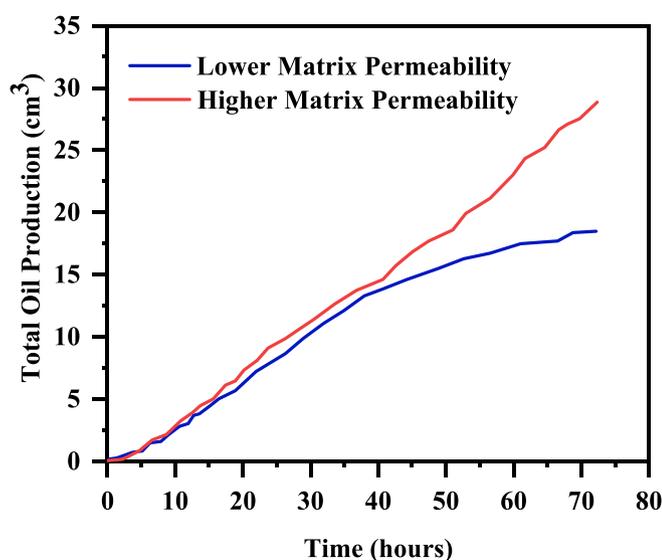


Fig. 20. Effect of the Reservoir Rock Permeability on Heavy Oil Recovery [5].

solvent chamber creation. Then, 1,982 m³/day was used as the maximum STG constraint. Different flow rates of solvents were then utilized as 425, 850, 1,133, 1,416, and 1,982 m³/day to be used as maximum STG constrain in the injection well, and upon outcomes, it was observed that by increasing injection binary solvent mixture rate from 425 m³/day injection rate up to 1,133 m³/day there was significant oil production rate enhancement, it tripled while further increasing more from 1,133 m³/day to 1,982 m³/day there were no noticeably significantly oil production rate increasing. From this study, it's clear that, though increased vapour injection rate improved the heavy oil recovery, it is necessary to conduct sensitivity analysis to capture the optimal vapour injection rate for a given solvent-heavy oil/bitumen system, hence minimizing solvent demand.

2.5.4. Interfacial tension/capillarity effects

Das and Butler [25] explored that VAPEX can be stimulated by capillary imbibition because capillary forces draw away the solvent-diluted oil. Again, analysis conducted by Ayub and Tuhinuzzaman [4] reveals that the existence of capillary pressure between oil and connate water improves the production of heavy oil in VAPEX since free gas

production was minimized, the solvent chamber was widespread and molecular diffusivity for the solvent was enhanced due to increased contact area when capillary forces existed. Experimental studies by CT scan and numerical simulation conducted by Cuthiell et al. [20] found that the transition zone was too thin if the capillary pressure were absent in the simulation model, while the transition zone matched with the one observed in the CT scan experiment when the capillary pressures effect was included in the numerical simulation.

2.5.5. Viscous fingering effect

Gas solvents usually have low viscosity, especially lower molecular weights hydrocarbon solvents, which can cause viscous fingering or unstable displacement to happen if these solvents are used to dilute extremely high viscous oil due to the significant mobility contrast between the heavy oil and solvents. The scenario was recognized by Cuthiell et al. [20] after conducting four tests in sand packs where the viscosity ratio between heavy oil and solvent was 8,000–86,000 and found that a single primary fingering occurred at the beginning of the solvent breakthrough and continued to grow because of mobilization of the oil at its edges. Fingering is the phenomenon that usually results in lower swept efficiency due to bypassed heavy oil portions by the used solvents in the VAPEX process and hence lower oil recovery factor, which reflects that it's a crucial factor that needs clarification for the decision of solvent vapour type selection and flow rate optimization to minimize fingering phenomena.

2.5.6. Well configuration and effective distance between injector and producer

Simulation studies are the primary tools that have been used to assess wells configurations and the distance between them (effective distance) due to several reservoir and fluid characteristics, and sensitivity analysis is very crucial in order to have a better choice of well locations and distance between them [51]. Apart from standard simulation tools, other numerical analysis tools that perform automatic optimization can be used to analyze the optimum well configurations and spacing of wells, as described by Khan and Awotunde [44], which used the particle swarm technique. According to the theoretically analytical flow equation presented by Butler and Mokrys [13], it is clear that the diluted heavy oil flow rate increases as the effective distance increases between injector and producer, as also reported by the VAPEX simulation study conducted by Mohammadpoor and Torabi [63], but due to some several actual field reservoir and fluid conditions, sensitivity analysis for these two parameters are recommended through simulations tools in order to have a desirable optimal well placement and distance between them for higher heavy oil/bitumen recovery in VAPEX processes.

3. Conclusions and recommendations

A comprehensive review of the VAPEX recovery technique for heavy oil and bitumen reservoirs is presented in this paper. It overviews the recovery mechanisms and developed analytical models with their limitations/uncertainties and factors affecting oil recovery, mostly through laboratory experiments and simulations. Crucial issues that were identified include the following:

- (1) Propane provided the best VAPEX process performance compared with other traditional solvents. Hybrid solvent systems can be utilized by minimizing heavier hydrocarbon solvent costs. It is recommended to conduct solvent-heavy oil/bitumen diffusivity and concentration relationship experiments for future VAPEX projects and, hence, use models that have solvent-heavy oil/bitumen diffusivity concentration-dependent terms in order to mimic the diffusion scenario at the solvent-heavy oil/bitumen interface.
- (2) Future experiments need to be conducted based on field core samples in order to reflect the actual field permeability data that

are usually in ranges of 1 mD ~ 10 D. Most of the developed analytical models were based on the spreading stage of VAPEX process, which implies that further studies must be strengthened for future VAPEX studies. There was limited knowledge on the development of transient mass transfer across the interface and increased solubility due to solvent vapour condensation in the fine capillaries driving mechanisms; hence, more analysis on these mechanisms can further be promoted in the next researches.

- (3) Solvent injection pressure, solvent injection rate, heavy oil/bitumen viscosity, reservoir permeability, interfacial/capillary pressure, viscous fingering and well configurations, and distance between injector and producers were the pinpointed discussed factors affecting heavy oil/bitumen recovery. Since each of the elements has its relationship with the oil recovery enhancement, detailed several sensitivity analyses studies for a given set of heavy oil-solvent set and reservoir properties from the experiments and simulations are highly devoted for the successful VAPEX projects performance.

CRedit authorship contribution statement

Morice Richard Mworira: Writing – review & editing, Writing – original draft, Software, Methodology, Conceptualization. **Zhengbin Wu:** Supervision, Conceptualization. **Kun Shu:** Writing – review & editing. **Shu Jiang:** Writing – review & editing, Funding acquisition. **Qiyang Gou:** Investigation, Resources. **Zhangxin Chen:** Supervision, Conceptualization. **Annasi Ayubu Said:** .

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

No data was used for the research described in the article.

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