

Oil & Natural Gas Technology

DOE Award No.: DE-FG26-06NT42745

Final Technical Report

SOLVENT BASED ENHANCED OIL RECOVERY FOR IN-SITU UPGRADING OF HEAVY OIL

Submitted by:
Florida International University
Miami, FL

Prepared for:
United States Department of Energy
National Energy Technology Laboratory

June 2009



Office of Fossil Energy

FINAL TECHNICAL REPORT

SOVENT BASED ENHANCED OIL RECOVERY FOR IN-SITU UPGRADING OF HEAVY OIL SANDS

DOE Award No. - DE-FG26-06NT42745

01/31/2006 – 01/30/2009

Principal Author

Dr. Norman Munroe

June 22th 2009

Applied Research Center, FIU Engineering Center

10555 West Flagler St.

Miami, Florida 33174

DISCLAIM

This report was prepared as an account of work sponsored by an agency of the United States government. Neither the United States government nor agency thereof, nor any of their employees, nor any of its contractors, subcontractors, nor their employees makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe upon privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States government or any agency thereof.

TABLE OF CONTENTS

ABSTRACT.....	4
INTRODUCTION.....	5
OBJECTIVES.....	6
CAPACITY OF SOLVENT-BASED INJECTION PROCESSES TO REDUCE UNWANTED SUBSTANCES.....	7
ECONOMIC MODELING OF HEAVY OIL EXPLOITATION AND UPGRADING.....	8
CONCLUSIONS.....	12
REFERENCES.....	13
APPENDIX – A.....	14
APPENDIX – B.....	24
APPENDIX – C.....	34
APPENDIX – D.....	35

ABSTRACT

With the depletion of conventional crude oil reserves in the world, heavy oil and bitumen resources have great potential to meet the future demand for petroleum products. However, oil recovery from heavy oil and bitumen reservoirs is much more difficult than that from conventional oil reservoirs. This is mainly because heavy oil or bitumen is partially or completely immobile under reservoir conditions due to its extremely high viscosity, which creates special production challenges. In order to overcome these challenges significant efforts were devoted by Applied Research Center (ARC) at Florida International University and The Center for Energy Economics (CEE) at the University of Texas. A simplified model was developed to assess the density of the upgraded crude depending on the ratio of solvent mass to crude oil mass, temperature, pressure and the properties of the crude oil. The simplified model incorporated the interaction dynamics into a homogeneous, porous heavy oil reservoir to simulate the dispersion and concentration of injected CO₂. The model also incorporated the characteristic of a highly varying CO₂ density near the critical point. Since the major challenge in heavy oil recovery is its high viscosity, most researchers have focused their investigations on this parameter in the laboratory as well as in the field resulting in disparaging results. This was attributed to oil being a complex poly-disperse blend of light and heavy paraffins, aromatics, resins and asphaltenes, which have diverse behaviors at reservoir temperature and pressures. The situation is exacerbated by a dearth of experimental data on gas diffusion coefficients in heavy oils due to the tedious nature of diffusivity measurements. Ultimately, the viscosity and thus oil recovery is regulated by pressure and its effect on the diffusion coefficient and oil swelling factors. The generation of a new phase within the crude and the differences in mobility between the new crude matrix and the precipitate readily enables removal of asphaltenes. Thus, an upgraded crude low in heavy metal, sulfur and nitrogen is more conducive for further purification.

INTRODUCTION

The oil recovery from heavy oil and bitumen reservoirs from conventional oil reservoirs is a major challenge because heavy oil or bitumen is partially or completely immobile under reservoir conditions due to its extremely high viscosity, which creates special production challenges. However, innovative drilling, completion, stimulation and monitoring techniques help make heavy-oil reservoirs profitable assets. Various recovery techniques for heavy oil production (such as Steam Assisted Gravity Drainage (SAGD), Single-Well Steam Assisted Gravity Drainage (SW-SAGD), Vapor Extraction Process (VAPEX) and Gas-Oil Gravity Drainage (GOGD) were analyzed. Additionally, current models used to evaluate the efficacy of solvent (gases) injection in heavy oil reservoirs to enhance oil recovery and their limitations were investigated. Moreover, viscous fingering phenomenon was reviewed in consideration that bubble nucleation events at high oil viscosity was more probable than bubble growth. These findings are discussed in a peer reviewed paper "*Advances in Heavy Oil Recovery*" (see Appendix A) that was presented in Fifth Latin American and Caribbean Conference for Engineering and Technology May 29-June 1, 2007, Tampico, México.

The use of solvent extraction and asphaltene precipitation, especially within the scope of the characterization of asphaltenes and their distribution and as a refining process was reviewed by CEE. As the solvent gets heavier and thus more compatible with the crude, it is able to extract more elements from the crude matrix. This implies that the "quality" of the upgraded crude (after solvent removal) is degraded. On the other hand, as solvents become lighter, the compatible or extractable components become lighter and thus the upgraded crude oil is less viscous. Instead of using a hydrocarbon as a solvent, there is great interest in using CO₂ as the proposed solvent. CO₂ has been used as an additive in the SAGD processes and its effect has been studied extensively. The phase behavior of CO₂/crude oil mixtures [1] presents an interesting property that will be used to determine the design of any CO₂ based heavy oil upgrading process. One interesting feature is that the density of CO₂ changes greatly with minimal change in pressure. The consequence of this is related to the fact that solvent extraction processes, as mentioned above, are directly tied to the density of the solvent being used. Thus, different "solvents" are produced with changes in pressure of the extraction. A higher pressure results in a denser CO₂, and thus a heavier solvent. This produces a lower quality of the upgraded crude. On the other hand, a lower pressure results in a lighter solvent and thus, a higher quality of the upgraded crude. One thing needs to be pointed out, as the solvent is more compatible with the crude oil (heavier solvent) it is able to extract heavier components (e.g. heavy resins) from the crude matrix leaving asphaltene micelles that contain less heavy resins that are less mobile. If the solvent is lighter, the resulting residue is lighter and likely more mobile. This indicates that there will be a tradeoff between the quality of the upgraded crude and the formation degradation that takes place due to the asphaltene precipitation.

Kapadia et al (2006) [2] developed a model where butane, which is known to have a much higher miscibility with heavy oil than CO₂ is used as a dispersant. In reality, with CO₂ as the vapex gas, there is a 4 stage process whereby mixing takes place. It is not feasible to consider this in the development of a simple model, since this phenomenon is highly complicated and not sufficiently well understood. Several variables were considered for the development of our mathematical model, which primarily calculates the mass dispersion of the gas into the oil. A lower value of diffusivity essentially means that the miscibility problems slow down the overall mixing and diffusion process.

In this research, a simplified model was developed by FIU/ARC to assess the density of the upgraded crude depending on the ratio of solvent mass to crude oil mass and the properties of the crude oil. The model sought to incorporate the characteristic of a highly varying CO₂ density near the critical point and incorporated the interaction dynamics into a reservoir simulation engine. The details of this model are described in a paper entitled, "Mathematical model of fluid injection in heavy oil reservoirs", that was presented at the Sixth LACCEI International Latin American and Caribbean Conference for Engineering and Technology (LACCEI'2008). (APPENDIX - B)

OBJECTIVES

A comprehensive research effort was designed to encompass the tasks outlined below. A subcontract was established with the University of Texas at Austin Bureau of Economic Geology's Center for Energy Economics. In general, this subcontract covered tasks 1, 2 and 8.

Task 1: Review in-situ upgrading processes proposed for heavy oil and the modeling tools developed for them.

Task 2: Quantify, based on available bitumen characterization data, the capacity of solvent injection based processes of addressing the need to reduce chlorides, nitrogen and other unwanted substances from upgraded crude.

Task 3: Develop a simplified model of the dynamics of injected fluids in heavy oil reservoirs.

Task 4: Propose physical models for the fluid dynamics and interactions of injected solvents in reservoirs. The simplified model will capture the essential physical phenomena with regard to fluid transport and crude upgrading extending the Task 3 results to crude upgrading.

Task 5: Propose accurate and flexible numerical models that implement the necessary elements of the physical models identified and developed in Task 4. Select a simulation engine based on its ability to incorporate the multi-component nature of the fluids in the reservoir, the possible need for accurate front tracking and the possibility of incorporating novel well architectures. The reservoir simulation model will need to be validated with eventual pilot test results for an extra-heavy crude oil reservoir.

Task 6: Propose the required well architecture and its influence on the in-situ upgrading process. The study will include optimization of completion/re-completion for the process, application of high tech wells (horizontal and multilateral), and viability of intelligent completions for downhole evaluation and control.

Task 7: Predict reservoir behavior under cyclic solvent injection. The validated model will be used to predict the behavior of a sample or hypothetical oil sand reservoir for which the characterization is readily available. The reservoir to be used for this stage will likely be the target of an eventual field demonstration test. This would allow the model to predict reservoir behavior after completed a production history match.

Task 8: Develop an economic model that provides cost estimates of the implementation of in-situ processing of crude oil based on reservoir performance and typical facilities and drilling costs. The critical variables that govern in-situ upgrading via cyclic solvent injection will be identified. This information will be the basis for the experimental design and conceptual engineering of the field demonstration test.

Task 9: Perform the experimental design and conceptual engineering for a field demonstration test.

Site

selection criteria will be developed in order to increase the feasibility of completing a test in the allotted time (including permitting and regulatory approval) and the representativeness of the test site. This is an important milestone since it will guide the selection of the location for a field demonstration of the process.

UT was responsible for providing FIU with a report (for a total of three) after the conclusion of each task:

- Conduct a review of in-situ upgrading processes for heavy oil and developed the modeling tools during Year 1.
- Address the need to reduce chlorides, nitrogen and other unwanted substances from upgraded crude during solvent injection based processes based on available data during Year 1.
- Provide a simple economic model with cost estimates for the implementation of in-situ processing of crude oil based on reservoir performance and typical facilities and drilling costs during Year 2.

CAPACITY OF SOLVENT-BASED INJECTION PROCESSES TO REMOVE UNWANTED SUBSTANCES

The capacity of solvent based processes of addressing the need to remove certain compounds from the crude/tar was quantified. Solvent based upgrading processes target the removal of asphaltenes from the crude matrix in addition to some additional heavy components. The process is a consequence of changing the matrix of fluids in which the asphaltenes are suspended (possibly in the form of micelles). The change in the fluid matrix leads to the precipitation of asphaltenes generating an additional phase. This phenomenon is observed both in heavy as well as in light crude oil (though asphaltene concentrations are much greater in heavier crude). Some heavy resins may be trapped within the asphaltene micelles and would be trapped in the precipitate. This highly viscous hybrid phase will have a lower mobility than the matrix, which now has an even lower viscosity due to the presence of the solvent. This allows for the treatment of the precipitate as a solid in suspension in the matrix.

Fortunately, the generation of a new phase and the marked difference in mobility can be used to physically separate the two. Given that many of the undesired heavy metals are associated with porphyrins and other types of asphaltenes that are present in the precipitate, upgraded crude can be obtained. In addition, some of the more recalcitrant compounds that have Sulfur and Nitrogen are also in the asphaltene fraction, leaving more easily treatable compounds in the upgraded crude.

In order to estimate the properties of the upgraded crude, the assumptions were made that the solvent process could remove 100% of the asphaltenes present in the crude. This is observed in standard tests using heavier solvents such as pentane. The estimates were made based on the publicly available assay of tar sand: the Surmont oil sands (or bitumen) of Athabasca though the results can be readily extended to the Schrader Bluff Pool at the Milne Point Unit in Alaska [3]. This Surmont oil sand is representative of the extensive oil sands deposits in North America. Based on the assay, we estimated the capacity to upgrade the crude and to determine the new contents of the undesired substances. The methodology used to estimate the capacity to upgrade crude and the properties of the upgraded crude can be extended to other crude for which an assay is available.

Presented below is a table that shows the properties of the original crude and that of an upgraded crude with 100% removal of asphaltenes which would serve as the upper bound of upgrading using this type of process from the perspective of heavy metal removal. Of interest is that the removal of the asphaltenes is able to considerably reduce heavy metal content. However, nitrogen, sulfur and acidic compounds are only reduced slightly. The reason for the lackluster results for the removal of certain substances is that these in particular are present in other components in addition to the asphaltene fraction with similar concentrations. That implies that even with the removal of asphaltenes, the concentration of these substances is only slightly modified. However, as will be seen below, the ability to process the crude is greatly improved.

Table 1 Content of heavy metals and other hetero-atoms in the original and upgraded crude

		Crude	Asphaltenes	Upgraded Crude
V	ppm	221	208.88	12.12
Ni	ppm	78.2	77.64	0.56
Fe	ppm	30.2	26.48	3.72
N	%	0.32	0.05	0.27
S	%	5	0.60	4.40
Acid Number		2.7	0.27	2.43

The main benefit is the reduction in the concentration of heavy metals. Vanadium, nickel and iron are found predominantly in asphaltenes and are mostly not present in the upgraded crude. This fact has an additional very important implication. Compounds such as sulfur and nitrogen are removed in

refinery processes using in most cases catalytic processes. The effectiveness of catalysts is reduced with the presence of heavy metals such as V and Ni. Given that these heavy metals have been removed from the matrix, catalytic processes will now be able to remove S and N from the upgraded crude with greater ease and at lower overall costs.

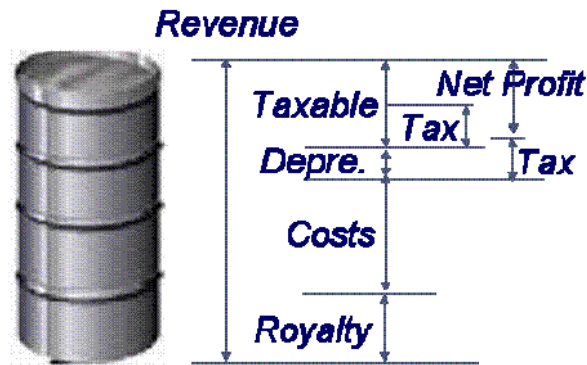
The results presented above are independent of the solvent used since they represent an upper bound for asphaltene removal. Depending on PVT conditions and the properties (affinity) of the solvent, different results can be obtained. Of interest is considering the use of CO₂ as the proposed solvent. CO₂ has been used as an additive in SAGD processes [4] and its effect has been studied. Increases in CO₂ injection in addition to the steam, where shown, at least modeled, to result in increased asphaltene deposition.

The phase behavior of CO₂/crude oil mixtures [5] presents an interesting property that was believed to determine the design of any CO₂ based heavy oil upgrading process. Given that CO₂ would be handled in its supercritical state, one interesting feature is that the density of CO₂ changes greatly with small changes in pressure. The consequence of this is related to the fact that solvent extraction processes, as mentioned above, are directly tied to the density of the solvent being used. Thus different "solvents" can be achieved with changes in the pressure of the extraction. Higher pressure results in a denser CO₂, and thus a heavier solvent. A heavier solvent is more compatible with heavier non-asphaltene fractions of the crude which are removed from the precipitate. This implies less quality of the upgraded crude. On the other hand, a lower pressure results in a lighter solvent and thus higher quality upgraded crude.

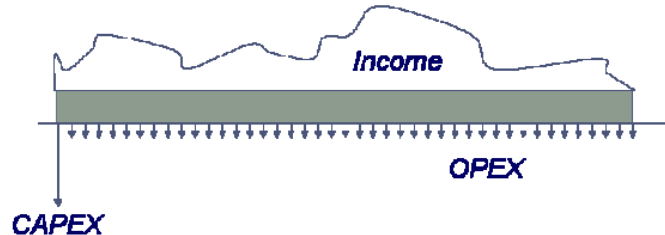
This behavior of CO₂ and crude oil mixtures will need to be addressed in any modeling attempt, especially in reservoir simulators since during production, near well bore pressure reduces rather quickly as distance to the well bore is reduced. This would lead to spatially varying interactions between the CO₂ solvent and the crude oil. Interestingly, the crude that is near the well bore, or has moved towards the well bore, should have already had contact with the solvent and will already have some level of upgrading. The additional interactions near the well bore will be able to upgrade the crude even more if the mobility ratio between the solvent upgraded crude mixture and the separation of phases are appropriate.

ECONOMIC MODELING OF HEAVY OIL EXPLOITATION AND UPGRADING

A set of simplified economic models were developed for the production and upgrading of heavy oil. Firstly, a model for the development of a Greenfield extra-heavy oil project was developed that incorporates the necessary capital expenses for midstream investments such as an export pipeline and an upgrading facility. The model incorporates uncertainty in capital expenditures, operating cost data, well production, in place crude quality, project delays and the obvious price uncertainty. The model serves as the baseline with which to compare the proposed in-situ upgrading process or any other process. As with most oil production projects, the fiscal regime is of great importance and frames the viability of investment. A simplified tax-royalty fiscal model was implemented in the model for the exploitation of an extra-heavy or tar sand resource. Depreciation of the capital expenditures is also incorporated and allows for scenarios which consider rapid depreciation.



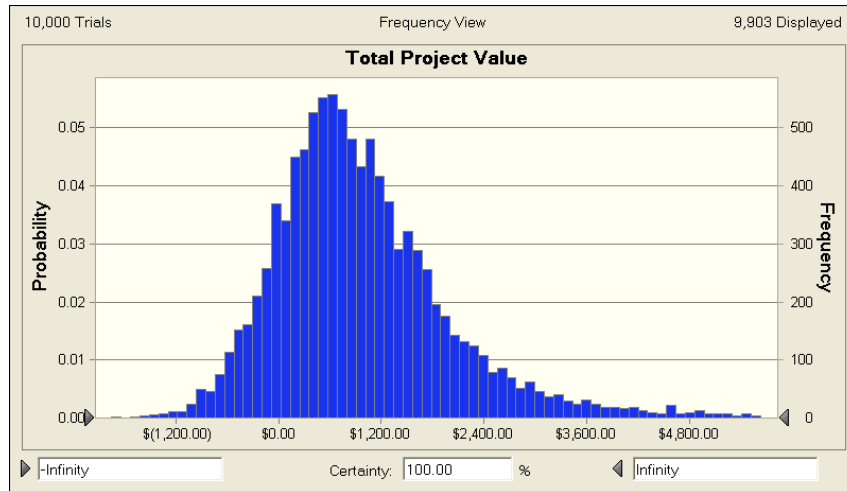
The economic model is a simplified discounted cash flow model. The model categorizes capital expenditures into two groups, large expenditures that are associated with the startup (initial wells, export pipeline, upgrader) and those made during production (additional well, flow stations). In addition to the additional capital expenditures that are made during the life of the project, certain expenses are made related to the operations (OPEX).



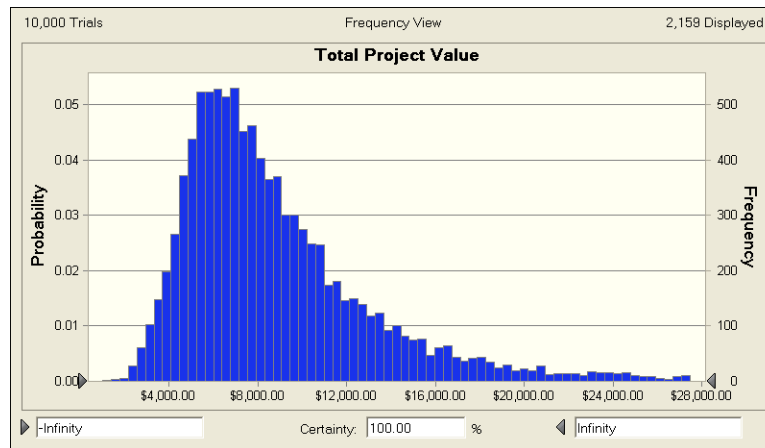
Based on this simplified cash flow model, the discounted net present value can be calculated for the project. In addition, once a fiscal regime is set, then the breakdown of cash flow into the mineral rights owner and the investor can be made. It should be clear that the potential value of the project is independent of the fiscal regime and that the fiscal regime determines the distribution of the project value between the mineral rights owner, the taxation authority and the project developer. In some cases, the mineral rights owner and taxation authority also participates as an investor in the project (one good example is that of a country in which the National Oil Company participates in the enterprise).

In order to provide an adequate dimension for the model, sample runs were performed to value a project with a target throughput of 100,000 barrels per day of upgraded crude oil. The project value is split between the owner of the mineral rights (royalty payments), the taxing authority and the company that is making the investment. In some cases, the owner of the mineral rights and the taxing authority are one and the same reducing the split into a company take and the government's take.

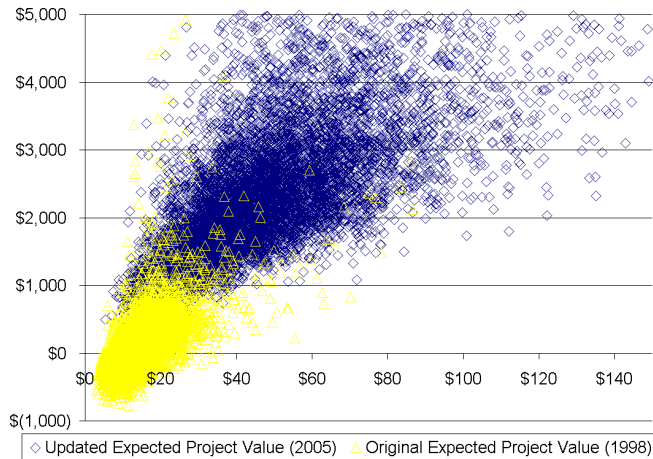
Model runs were performed for a hypothetical project [7] with a production start date of 1998 (low price expectations). This resulted with in a distribution of net present value as shown below and a NPV(P50) of \$815 million.



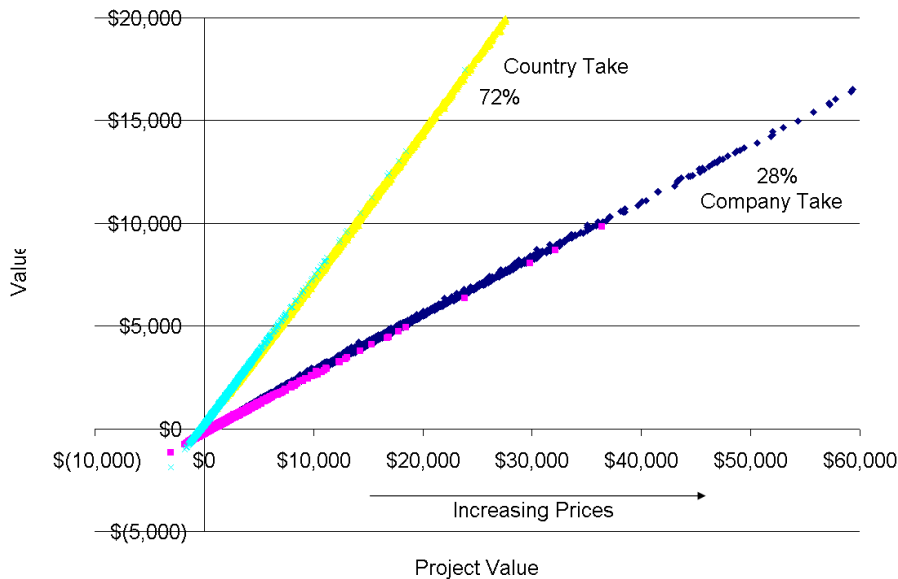
Interestingly, low price expectations were not met, but rather prices rose considerably. The project was then re-evaluated fixing prices between 1998 and 2006 to the real market prices and leaving the rest of the project with current higher price expectations. This results in a project with a NPV distribution as shown below, with a NPV(P50) of \$7,786 million.



During the 7 year period, given the increase in oil prices, the expected value of the project increased an order of magnitude. Moreover, during the first 7 years, the original expected value was achieved leaving 90% of the value for future returns. The plot below shows the cloud of possible values for the project as a function of the price of crude in year 10. The considerable increase in value in the project is a clear consequence of the rise in oil prices during that period.

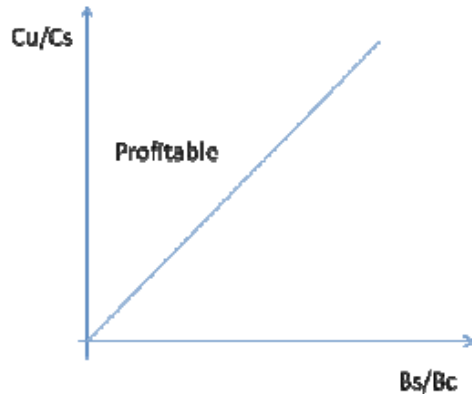


The value of the project is distributed among the owner of the resource, the taxing authority and the company that makes the necessary investments. In the case considered here, the national oil company is assumed to participate as an equal partner in the venture, increasing the government take by adding to the royalty and tax payments, half of the profits associated with the project. The distribution of value with the assumed fiscal regime is shown below in which the horizontal axis is the value of the project, and the different takes are shown.



The economics of the solvent based upgrading process as proposed here is a function of many variables. From the perspective of an open system that incorporates all of the internal processes, the variables that determine the economics of the process are: cost of solvent; replacement solvent per cycle; value of original heavy crude oil; cost of upgrading said heavy crude oil to a given quality achievable via solvent based methods; value of solvent based upgraded crude. The process is deemed to be profitable when compared to the conventional upgrading process it replaces if the ratio of the following two dimensionless quantities is greater than one: the first dimensionless quantity is the ratio of the cost of conventionally upgrading a barrel of heavy crude to the cost of a barrel of solvent; the second dimensionless quantity is the ratio between the barrels of solvent that need to be replaced per cycle to the barrels of upgraded crude that are produced per cycle. The most efficient process would

have no losses associated with the solvent. This would imply that the solvent based process would be attractive if the cost of conventionally upgrading crude was greater than a barrel of solvent. This can be repeated for different values of the second dimensionless quantity to construct the following plot.



Current estimates for conventionally upgrading heavy crude from 8API to 16API are of the order of \$8 per barrel. If that is compared with the cost of a mixture of equal parts propane and butane (cost approximately \$2 per gallon or \$84 per barrel), the maximum allowable loss of solvent per crude produced per cycle would be slightly less than 10%.

CONCLUSIONS

The major challenge in heavy oil recovery is its high viscosity. As a result, most researchers have focused their investigations on this parameter in the laboratory as well as in the field with disparities in the results obtained. This may be attributed to the fact that oil is a complex polydisperse blend of light and heavy paraffins, aromatics, resins and asphaltenes which have diverse behaviors at reservoir temperature and pressures and that there is a dearth of experimental data on gas diffusion coefficients in heavy oils due to the tedious nature of diffusivity measurements. The effect of pressure on the diffusion coefficient and oil swelling factors, ultimately regulate the viscosity and thus oil recovery. The generation of a new phase within the crude and the differences in mobility between the new crude matrix and the precipitate readily allows for the removal of asphaltenes in-situ and the production of an upgraded crude low in heavy metal content that can be more easily treated to remove additional substances such as Sulfur and Nitrogen. Moreover, a successful mathematical model was developed to simulate the dispersion and concentration of an injected gas into a homogeneous, porous heavy oil reservoir at a specific temperature and pressure.

REFERENCES

1. J. Hwang et al, Phase Behavior of CO₂/Crude Oil Mixtures in Supercritical Fluid Extraction System: Experimental Data and Modeling, Ind. Eng. Chem. Res. 1995, 34, 1280-1286
2. Kapadia A. Ronak^a, Upreti R. Simant^a, Lohi Ali^{a,b} and Chatzis Ioannis^b. (2006). "Determination of gas dispersion in vapor extraction of heavy oil and bitumen". ^aDepartment of Chemical Engineering, Ryerson University, Toronto, Ontario, Canada M5B 2K3, ^bDepartment of Chemical Engineering, University of Waterloo, Waterloo, Ontario, Canada N2L 3G1.
3. US DOE Report DOE/BC/14864-15 (DE-96006092) 1995.
4. S. Canbolat et al, Asphaltene Deposition During SAGD: Effect of Non-Condensable Gases, Petroleum Science and Technology, 24:69-92, 2006.
5. J. Hwang et al, Phase Behavior of CO₂/Crude Oil Mixtures in Supercritical Fluid Extraction System: Experimental Data and Modeling, Ind. Eng. Chem. Res. 1995, 34, 1280-1286
6. The fiscal regime considered was the regime existing in 1998 in Venezuela for the exploitation of the Faja del Orinoco. Tax-royalty regimes in North America have a similar structure and can be incorporated rather easily. Current increases in royalty and tax rates in Alberta is modifying the viability of similar large scale production/upgrading projects.

APPENDIX – A

Fifth LACCEI International Latin American and Caribbean Conference for Engineering and Technology (LACCEI'2007) "Developing Entrepreneurial Engineers for the Sustainable Growth of Latin America and the Caribbean: Education, Innovation, Technology and Practice" 29 May – 1 June 2007, Tampico, México .

Advances in Heavy Oil Recovery

Norman D.H. Munroe
Applied Research Center, Florida International University

Maria .C. Bravo
Applied Research Center, Florida International University

Puneet K. Singh Gill
Applied Research Center, Florida International University

ABSTRACT

With the depletion of conventional crude oil reserves in the world, heavy oil and bitumen resources appear to have great potential to meet the future demand for petroleum products. However, oil recovery from those sources is fraught with difficulties as compared to conventional oil reservoirs primarily due to high viscosity even under thermodynamic reservoir conditions, which creates special production challenges. Conventional enhanced oil recovery methods also possess important limitations, ranging from operational difficulties to predictive capabilities. With the advent of innovative drilling technologies, in-situ injection of fluids, simulation and monitoring techniques, heavy-oil reservoirs have been rendered profitable assets. This paper analyzes various recovery techniques for heavy oil production and identifies limitations of present models to evaluate the efficacy of solvents (gases) injection in heavy oil reservoirs as an enhanced oil recovery method. The so far known viscous fingering phenomenon is reviewed considering bubble nucleation events at high oil viscosity as being more probable than bubble growth and coalescence. Possible effects on relative permeability under different operation conditions are discussed.

Keywords: heavy oil, viscosity, modeling, diffusion-coefficient, solvent injection

INTRODUCTION

Heavy oil resources appear to have great potential to meet the future demand for petroleum products. However, oil recovery from those sources is fraught with difficulties as compared to conventional oil reservoirs primarily due to high viscosity even under thermodynamic reservoir conditions, which create special production challenges. Many researchers (Butler and Mokrys, 1989), (Das and Butler, 1996a, 1998b), (Butler and Jiang, 2000), (Boustani and Maini, 2001), (Nghiem et al, 2001), (Cuthiell et al, 2003), (Jha, 1986) have investigated the injection of semi-miscible solvents for enhanced recovery of heavy crude oils from laboratory scale to pilot plant and commercial scale [Turta and Singhal, 2004]. Others have attempted to develop predictive models (Kapadia et al, 2006), (Vafaie-Sefti and Mousavi-Dehghani, 2006), (Cuthiell et al, 2003) to simulate the dynamics of solvents-heavy oil interactions in order to improve productivity. This paper analyzes various recovery techniques for heavy oil production and identifies limitations of present models to evaluate the efficacy of solvents (gases) injection in heavy oil reservoirs as an enhanced oil recovery method.

The injection of hydrocarbon or non-hydrocarbon solvents to recover heavy oil involves to a greater or lesser extent: (a) a reduction of its viscosity through molecular diffusion (Das and Butler, 1996a), (Boustani and Maini, 2001), (Nghiem et al, 2001), (Cuthiell et al, 2003), (Jha, 1986), (b) swelling of the oil phase (Yang, and Gu, 2006), (c) reduction of the interfacial tension, and (d) miscibility and mixing of gas and oil. Therefore, the parameters of interest are the diffusion coefficient of the solvent in heavy oil under the practical reservoir conditions and reservoir simulation and field design (Yang and Gu, 2006) and Oil swelling factor of a heavy oil-solvent system, where crude oil swells due to solvent dissolution. Oil swelling, which is defined as the ratio of the volume of the solvent-saturated heavy oil to the volume of the original heavy oil without any solvent dissolution, is believed to mobilize residual oil (Campbell, B.T. (1983) as well as increase oil saturation and consequently the relative permeability of the oil (Yang and Gu, 2006).

The phenomenon of dispersion (mixing of the solvent with crude oil) is considered crucial to the economic viability of the Vapex process. The porosity of the reservoir media augments this phenomenon possibly due to an increase in molecular diffusivity with solvent concentration leading to decreased oil viscosity, an increase in gas/oil interfacial area and interfacial instabilities (Kapadia et al 2006).

The injection of Carbon dioxide (CO₂) in oil reservoirs is a very common recovery method. The similarity in densities of CO₂ and oil minimizes unfavorable gravity segregation, commonly observed when hydrocarbon gases are used as solvents, while the most important beneficial effects of hydrocarbon gases injection remain.

Depending on thermodynamic reservoir pressure and temperature, CO₂ could be miscible or immiscible with crude. At a constant reservoir temperature, the pressure will define the degree of miscibility reached and the minimum pressure at which miscibility is achieved is defined as the minimum miscibility pressure (MMP). CO₂ and crude are not initially miscible at first contact. However, upon repeated contact through a kind of evaporation-condensation process (Jarrel et al., 2002), miscibility is achieved.

The sweep efficiency is strongly subordinated to the miscibility condition at which the whole flood and recovery process take place. As previously mentioned, principal mechanisms that contribute to the improved recovery when CO₂ is dissolved in oil are summarized as (Qamar and Islam, 2000; Jha, 1986): oil viscosity reduction, oil swelling, interfacial tension reduction, water-oil emulsification (formation of emulsions that control the water mobility) and well stimulation effects (CO₂ huff-n-puff, CO₂ slugs and water flooding, WAG, *Blowdown*).

It has been reported that miscible CO₂ displacement results in around 22% of incremental recovery, while immiscible displacement recovery is approximately 10%. Consequently, operators have traditionally preferred deeper reservoirs, where pressures are above MMP (Qamar and Islam, 2000). However, *Blowdown* following an immiscible CO₂ flood is considered a very effective method in recovering up to 30% of initial oil in place (Jha, 1986).

At miscibility conditions, the viscosity of CO₂ is 1 to 2 orders of magnitude smaller than that of a light oil (viscosity of around 2 cP), and is about 5 to 8 orders of magnitude less than that of a heavy oil (1000 cP). CO₂ injection below the MMP, results in an adverse CO₂/oil mobility relation, which is deleterious to heavy oil recovery, and implies poor sweep efficiency due to the viscous fingering phenomena (Sahimi, 1993).

The CO₂ flooding above MMP results in the formation of a single phase that is less viscosity than the previous oil phase (a previously mentioned enhanced oil recovery mechanism), which improves oil mobility and thus its recovery. However, CO₂ injected at pressures below the MMP (external gas drive) behaves differently as compared to CO₂ injected at pressures above MMP. Nevertheless, throughout the fluids recovery process, the pressure in the reservoir becomes lower than the MMP. In this last scenery, internal or solution gas drive is known to occur as well as viscous fingering and CO₂ breakthrough is dependent on the flow regime, (Moulu, 1989).

Figure 1 illustrates a plot of pressure dependence with distance from the well for a hypothetical heavy oil reservoir. The balance of forces, viscous and capillary, that control the flow dynamic is identified with respect to the well location though the capillary number (Ca), which is calculated as:

$$Ca = \frac{\partial P / \partial r}{P_c}, \quad (1)$$

where, $\partial P / \partial r$ is the pressure gradient considering radial symmetry:

$$\partial P / \partial r = r_w u_w \mu \phi / k \cdot r \quad (2)$$

and P_c is the capillary pressure given by:

$$P_c = \frac{2\sigma}{r_p} \cos \theta. \quad (3)$$

Ca values, represented in Figure 1, were obtained considering an average pore diameter $r_p = 100 \text{ }\mu\text{m}$, an interfacial tension $\sigma = 40 \text{ mN/m}$, $\theta = 0$ (completely oil wet) and the data is offered in Table 1.

Notice in Figure 1 how predominance of capillary forces increases with distance from the well, while the dominance of viscous forces increases with the inverse of that distance. The balance of these forces determines the gas phase distribution during its release and transport. From cold production studies of heavy oil reservoirs (Tang and Firoozabadi, 2003) it is known that fingering could not occur and bubbles flow can be developed depending on flow regime. Nucleation, growth, coalescence and break up of bubbles are competing phenomena, which determine the gas dynamics. During the experiment of Tang and Firoozabadi (2003), the capillary number was determined to be approximately 2×10^{-3} , and the flow of bubbles was observed during almost the entire experiment, indicating the prevalence of viscous flow. Similarly, the physical mechanisms that govern this dynamic system will control the CO₂-oil flow if, after CO₂ miscible injection, the pressure drops below the MMP. Under *Blowdown* events, the viscous force is dominant and consequently the flow of bubbles is even more probable.

One of the greatest challenges at field scale simulations of cold production is to quantify the spatial and temporal changes of gas release and its transport processes. This is very relevant for oil recovery. Bubbles flow Dynamics are not adequately described by the conventional Darcy approach for two-phase flow (Bravo, 2007), because the extended Darcy equation disregards the contribution of momentum interchanges among phases explicitly captured in generalized equations via viscous coupling terms (Kalaydjian, 1990):

$$v_o = \frac{k \cdot kr_o}{\mu_o} (-\nabla p_o) + \frac{k \cdot k_{go}}{\mu_g} (-\nabla p_g), \quad (4)$$

$$v_g = \frac{k \cdot kr_g}{\mu_g} (-\nabla p_g) + \frac{k \cdot k_{og}}{\mu_o} (-\nabla p_o). \quad (5)$$

Considering that there is no saturation gradient, the capillary pressure gradient should be zero and therefore $\nabla P_o = \nabla P_g$. Thus, previous Eqs. (4) and (5) can be written as:

$$v_o = \frac{k \cdot kr_o^{ap}}{\mu_o} (-\nabla p_o), \quad (6)$$

$$v_g = \frac{k \cdot kr_g^{ap}}{\mu_g} (-\nabla p_o), \quad (7)$$

with apparent relative permeabilities given by:

$$kr_g^{ap} = kr_g + \frac{\mu_g}{\mu_o} k_{og} = kr_g \left(1 + \frac{\mu_g}{\mu_o} \frac{k_{og}}{kr_g} \right), \quad (8)$$

$$kr_o^{ap} = kr_o + \frac{\mu_o}{\mu_g} k_{go} = kr_o \left(1 + \frac{\mu_o}{\mu_g} \frac{k_{go}}{kr_o} \right). \quad (9)$$

Even though it is very important to disconnect viscous coupling of relative permeability in order to understand the physics that govern the curves behavior, equations (6) to (9) indicate that in principle the apparent relative permeability can be considered a viable alternative to illustrate all of the effects. However, it is important to keep in mind that this concept is physically different from the relative permeability. In fact, apparent relative permeability can be greater than one, depending on the relevance of viscous coupling with respect to the purely Darcy terms (relative permeability terms) and spatial and temporal distribution of the phases.

The bubbles flow observed under predominantly viscous flow regime is very favorable to oil flow, because of the viscous coupling contribution. Also, the apparent relative permeability has previously been determined to be greater than one, while capillary numbers guarantee the viscous flow regime. Therefore, operating conditions should be carefully selected to maximize the coupling flow during CO₂ injection for efficient oil production. Figure 2 illustrates the effect of recovery stages on residual oil saturation (*S_{or}*). Notice that only when the injection rate was 0.6 m/d, that the Blowdown produced a significant reduction of *S_{or}*. A lower rate of injection enables more CO₂-oil contact time and depending on production rate, the coupling effect could play an important role. No physical explanation has been espoused for this behavior and other similar observations and it is our opinion that the solution gas driven mechanism of flow should be better elucidated by modeling of the dynamics taking into consideration the effect of viscous coupling.

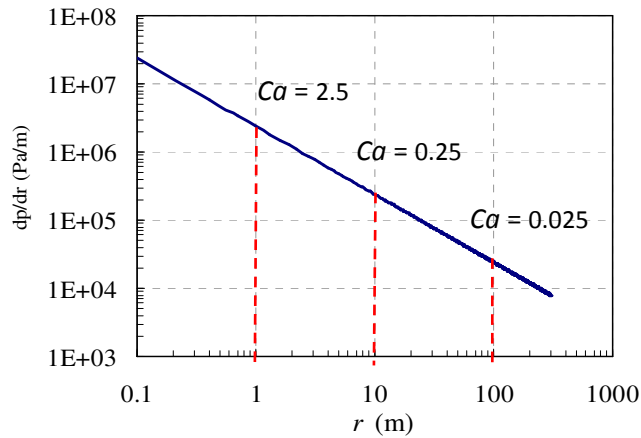


Figure 1: Pressure gradient vs. Distance to the well, considering radial symmetry and data of Table 1.

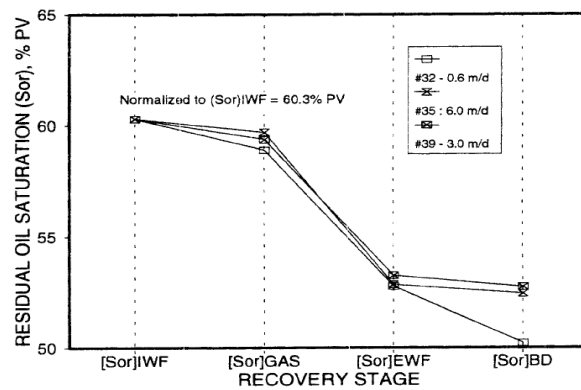


Figure 2: Effect of CO₂ injection rate on waterflood residual oil saturation. IWF: Initial Waterflood, GAS: Gas injection, EWF: Extended Waterflood, BD: Blowdown. Taken from: Srivastava and Huang (1994).

Table 1: Parameters of a hypothetical heavy oil reservoir (based on current data)

Permeability, k (m^2)	5×10^{-12}
Porosity, ϕ (fraction)	0.25
Crude viscosity, μ_o (Pa.s)	3
Well radius, r_w (m)	0.1
Thickness of producer layer, h (m)	20
Production rate, q_w (m^3/s)	5×10^{-4}

1.1 DIFFUSION COEFFICIENTS AND OIL SWELLING FACTORS FOR CARBON DIOXIDE, METHANE, ETHANE AND PROPANE

Dynamic Pendant Drop Volume Analysis (DPDVA) method (Chaodong Yang and Yongan Gu) is used to measure the diffusion coefficients and oil swelling factors. The oil swelling factor of a heavy oil-solvent system, solubility and viscosity of a heavy oil solvent system are interrelated but the former increases with pressure. The DPDVA method is also applicable for measuring the apparent diffusion coefficient and the apparent oil swelling factor of heavy oil - solvent mixture system.

It is speculated that the diffusion coefficient of a solvent in heavy oil increases with pressure, which can be verified by the determination of the solvent diffusion coefficients at different pressures. Comparison of four solvent injection systems (carbon dioxide, methane, ethane and propane) revealed that the volume increases of the dynamic pendant heavy oil drop surrounded by propane is the largest. This means that the specific surface area of the pendant oil drop is larger at a higher pressure and that the oil drop can be more easily saturated with the solvent. Research indicates that propane has the strongest oil swelling effect due to its high solubility in heavy oil among the four solvents studied.

1.2 EFFECT OF PRESSURE ON THE SOLVENT DIFFUSION COEFFICIENT AND ON OIL SWELLING FACTOR

Studies show that the diffusivities of ethane and propane increase with the dimensionless pressure, which is P/P_v . The solvent diffusivity coefficient and solubility of a solvent increases with pressure which further leads to decrease in oil viscosity. It has been found that the diffusivity of ethane and propane increases with the dimensionless pressure as compared to carbon dioxide and methane.

The oil swelling factors of ethane and propane are large and close to each other, whereas, the oil swelling factors of carbon dioxide and methane are much smaller. Among the four pure solvents (carbon dioxide, methane, ethane and propane), propane has the largest oil swelling factor, which indicates that a significant amount of this solvent dissolves into the heavy oil at a pressure close to its dew point.

2. INJECTION OF COPOLYMER IN ENHANCED OIL RECOVERY

(Sabhapondit et al, 2001) prepared a high molecular weight ($>10^6$) copolymer of *N,N*-dimethyl acrylamide with Na-2-acrylamido-2-methylpropanesulfonate and studied the efficiency of the copolymer as an enhanced oil recovery (EOR) chemical. The recovery efficiency is a function of three factors: (i) Areal sweep efficiency, (ii) Contact factor, and (iii) Displacement efficiency. The sweep efficiency is related to the mobility ratio of the injected fluid (water) to the displaced fluid (oil), which is defined as:

$$\text{mobility.ratio}(M) = \frac{\text{mobility.of.injected.fluid}}{\text{mobility.of.displaced.fluid}} = \frac{K_w/\mu_w}{K_o/\mu_o}$$

where, K_w and K_o are the permeabilities of water and oil, respectively, while μ_w and μ_o are the viscosities of water and oil, respectively. The equation indicates that oil recovery can be increased by increasing the viscosity or decreasing the permeability of aqueous phase in the reservoir.

2.1. DETERMINATION OF PERMEABILITY

The absolute permeability of the unconsolidated sand is determined using Darcy's law,

$$k = \frac{\mu L Q}{\Delta P A}$$

where, μ is the viscosity of the fluid, A is the area of cross section of the column, Q is the flow rate of the fluid, ΔP is differential pressure, and L is the length of the column. If μ is expressed in cp, A in cm^2 , Q in mL/s, ΔP in atm, and L in cm, k will be in Darcy. The parameter k was determined from the slope of the plot of Q vs ΔP using freshwater as the fluid phase. In the case of two phase flow, the effective permeability of the sand to polymer solution was determined using the same equation. It is given as

$$k_1 = \frac{\mu_1 L Q_1}{\Delta P_1 A}$$

where, k_1 is effective permeability, μ_1 is viscosity of the polymer solution when attains steady state, Q_1 is the steady-state flow rate, and ΔP_1 is the differential pressure at steady state.

The permeability reduction due to polymer flooding is determined as follows:

$$\text{Permeability Reduction} = \frac{(\text{Effective permeability before flooding} - \text{Effective permeability after flooding})}{\text{Effective permeability before flooding}} \times 100$$

3. DETERMINATION OF GAS DISPERSION

A mathematical model (Kapadia et al 2006) determined gas dispersion and solubility in a laboratory scale physical model of the VAPEX process using live oil. In this investigation, a block is initially exposed from its sides to a solvent gas at a given pressure and temperature, which diffuses and is absorbed into the medium. This results in the reduction of the viscosity of heavy oil and bitumen causing it to drain under gravity.

4. MEASUREMENT OF GAS DIFFUSIVITY

The molecular diffusion of gases plays a very important role. The gas diffusion coefficient has a direct impact on the amount of gas that is released and the level of super saturation that exists during the pressure depletion. In this investigation, a simple experimental technique for measuring the gas diffusivity coefficient in heavy oils was developed. The diffusion coefficient of carbon dioxide and methane were measured from the rate of gas absorbed at high pressure and employing the diffusion equation with the gas material balance equation (derived from previous data).

4.1 TEMPERATURE FLUCTUATIONS

Fluctuations in temperature further leads to small affect on the pressure. As the pressure decreases, the equilibrium concentration of gases at the interface also decreases, and leads to an increase in their solubility. However, the effect of decreasing temperature counteracts the effect of decreasing pressure on the equilibrium concentration of gas at the interface. Therefore, it can be concluded that the overall effect of temperature fluctuations on the test is relatively small. The change in gas pressure during the test for the CO₂ oil system was more significant as compared to that of the methane oil system. Therefore, the determination of the diffusion coefficient for CO₂ oil system is expected to be more reliable due to the longer time period.

5. FRICTION (f) THEORY

The friction theory for oil viscosity modeling (Quiñones-Cisneros et al 2001) can deliver highly accurate viscosity modeling above the saturation pressure and also predicts the liquid phase viscosity at pressures below the saturation pressure. A tuned f-theory model delivers accurate modeling of different types of light and heavy oil. Thus, the f-theory is a powerful tool for applications such as reservoir simulations and has been used to characterize oils. The f-theory provides good predictive viscosity performance for reservoir fluids.

6. CONCLUSION

The major challenge in heavy oil recovery is its high viscosity. As a result, most researchers have focused their investigations on this parameter in the laboratory as well as in the field with disparities in the results obtained. This may be attributed to the fact that oil is a complex polydisperse blend of light and heavy paraffins, aromatics, resins and asphaltenes which have diverse behaviors at reservoir temperature and pressures and that there is a dearth of experimental data on gas diffusion coefficients in heavy oils due to the tedious nature of diffusivity measurements. In addition, molecular diffusion is considered to play a major part in supercritical fluid extraction of heavy oils by miscibility displacement. Furthermore, the effect of pressure on the diffusion coefficient and oil swelling factors, ultimately regulate the viscosity and thus oil recovery. Thus, there is great need for better correlations between experimental and theoretical studies and the measurement of gas diffusivity in heavy oils can provide valuable additional information on the equilibrium solubility of the gas at the test pressure.

REFERENCES

Akin Serhat and Bagci Suat. (2001). "A laboratory study of single-well steam-assisted gravity drainage process". Petroleum and Natural Gas Engineering Department, Middle East Technical University, Inonu Bulvari 06531, Ankara, Turkey.

Barillas, J.L.M.^a, Dutra, T.V, Jr.^a and Mata, W.^b. (2006). "Reservoir and operational parameters influence in SAGD process". ^aUniversidade Federal do Rio Grande do Norte, Departamento de Engenharia Química — CT — Campus Universitário UFRN, Lagoa Nova, Natal/RN — CEP: 59078-970, Brazil and ^bUniversidade Federal do Rio Grande do Norte, Departamento de Engenharia Elétrica — CT — Campus Universitário UFRN, Lagoa Nova, Natal/RN — CEP: 59078-970, Brazil.

Boustani, A., and Maini, B.B. (2001). "The role of diffusion and convective dispersion in vapor extraction process". J. Can. Pet. Technol. 40 (4), pp 68-77.

Bravo, M.C., Araujo, M. and Lago, M.E. (2007). "Pore network modeling of two-phase flow in a liquid-(disconnected) gas system". Physica A 375, pp 1-17.

Butler, R.M., and Jiang, Q. (2000). "Improved recovery of heavy oil by VAPEX with widely spaced horizontal injectors and producers". J. Can. Pet. Technol. 39 (1), pp 48-56.

Butler, R.M., and Mokrys, I.J. (1989). "Solvent analog model of steam-assisted gravity drainage". AOSTRA J. Res. 5, pp 17-32.

Campbell, B.T. (1983). "Flow Visualization of CO₂-Crude Oil Mixtures", Master Thesis, Department of Petroleum and Natural Gas Engineering, New Mexico Institute of Mining and Technology, Socorro, New Mexico.

Canbolat, S.^a, Akin, S.^a, and Kovscek, A.R.^b (2004). "Noncondensable gas steam-assisted gravity drainage". ^aPetroleum and Natural Gas Engineering Department, Middle East Technical University, 06531, Ankara, Turkey and ^bDepartment of Petroleum Engineering, Stanford University, Stanford, CA 94305-2220, USA.

Cuthiell, D., McCarthy, C. Frauenfeld, T, Cameron, S., and Kissel, G. (2003). "Investigation of the VAPEX process using CT scanning and numerical simulation". J. Can. Pet. Technol. 42 (2), pp 41-48.

Das, S.K., and Butler, R.M. (1996). "Diffusion coefficients of propane and butane in Peace River bitumen". Can. J. Chem. Eng. 74, pp 985-992.

Das, S.K. Butler, R.M. "Mechanism of the vapor extraction process for heavy oil and bitumen". J. Pet. Sci. Eng. 21, pp 43-59.

Das Swapan K., and Butler Roger M. (1998). "Mechanism of the vapor extraction process for heavy oil and bitumen". Department of Chemical and Petroleum Engineering, The University of Calgary, Calgary, AB, Canada T2N 1N4.

Emberley, S.^a, Hutcheon, I.^b, Shevalier, M.^b, Durocher, K.^b, Gunter, W.D.^c, and Perkins, E.H.^c. (2004). "Geochemical monitoring of fluid-rock interaction and CO₂ storage at the Weyburn CO₂-injection enhanced oil recovery site, Saskatchewan, Canada". ^aEn Cana Corporation, 421 7th Avenue SW, P.O. Box 2850, Calgary, AB, T2P 2S5, Canada, ^bDepartment of Geology and Geophysics, University of Calgary, 2500 University Drive NW, Calgary, AB, T2N 1N4, Canada ^cAlberta Research Council, Edmonton, AB, T6N 1E4, Canada.

Jha, K. N. (1986). "A lab study of heavy oil recovery with carbon dioxide". J. of Canadian Petroleum Technology, pp 54-63.

Kapadia A. Ronak^a, Upreti R. Simant^a, Lohi Ali ^{a-b} and Chatzis Ioannis^b. (2006). "Determination of gas dispersion in vapor extraction of heavy oil and bitumen". ^aDepartment of Chemical Engineering, Ryerson University, Toronto, Ontario, Canada M5B 2K3, ^bDepartment of Chemical Engineering, University of Waterloo, Waterloo, Ontario, Canada N2L 3G1.

Luhning, R.W., Das, S.K., Fisher, L.J., Bakker, J., Grabowski, J., Engleman, J.R., Wong, S., Sullivan, L.A., and Boyle, H.A. (2003). "Full scale VAPEX process-climate change advantage and economic consequences". J. Can. Pet. Technol. 42 (2), pp 29-33.

Moulu, J. C. (1989). "Solution gas drive: Experiments and simulation". Petroleum Science and Engineering, 2, pp 379-386.

Nabipour, M.^a, Escrochi, M.^a, Ayatollahi, S.^{a-b}, Boukadi, F.^c, Wadhahi, F.^b, Maamari, R.^b, and Bemani, A. (2006). "Laboratory investigation of thermally-assisted gas-oil gravity drainage for secondary and tertiary oil recovery in fractured models". ^aCollege of petroleum and Chemical Engineering, Shiraz University, Shiraz, Iran, ^bDepartment of Petroleum and Chemical Engineering, College of Engineering, Sultan Qaboos University, Al-Khod, Oman and ^cThe Petroleum Institute, P.O. Box 2533 Abu-Dhabi, United Arab Emirates.

Nestor V. Queipo, Javier V. Goicochea and Salvador Pintos. (2002). "Surrogate modeling-based optimization of SAGD processes". Applied Computing Institute, Faculty of Engineering, University of Zulia, Zulia, Venezuela.

Nghiem, L.X., and Kohse, B.F., Sammon, P.H. (2001). "Compositional simulation of the VAPEX process". J. Can Pet. Technol. 40 (8), pp 54-61.

Qamar, M. M., and Islam, M. R. (2000). "CO₂ Injection in the Weyburn Field of Canada: Optimization of Enhanced Oil Recovery and Greenhouse Gas Storage With Horizontal Wells", SPE#59327.

Quiñones-Cisneros E. Sergio, Zéberg-Mikkelsen K. Claus. and Stenby H. Erling. (2001). "The friction theory for viscosity modeling: extension to crude oil systems". Department of Chemical Engineering, Center for Phase Equilibria and Separation Processes (IVC-SEP), Technical University of Denmark, Building 229, DK-2800 Lyngby, Denmark.

Sabhapondit Anupom, Borthakur Arun, and Haque Inamul. (2001). "Water soluble Acrylamidomethyl propane Sulfonate (AMPS) Copolymer as an Enhanced oil Recovery Chemical". Regional Research Laboratory, Jorhat-785006, Assam, India, and Dibrugarh University, Dibrugarh 786004, Assam, India.

Sahimi, M. (1993). "Flow phenomena in rocks: from continuum models to fractals, percolation, cellular automata, and simulated annealing". *Reviews of Modern Physics* 65, 1393-1534.

Srivastava, R.K., and Huang, S.S. (1994). "Heavy oil recovery by subcritical carbon dioxide flooding". III Latin American/Caribbean Petroleum Engineering Conference, Buenos Aires, Argentina, pp 27-29, April (SPE#27058).

Tang, G-Q, and Firoozabadi, A. (2003). "Gas and liquid phase relative permeabilities for cold production from heavy oil reservoirs". *SPE Reservoir Evaluation & Engineering*, pp 70-80.

Turta, A.T., and Singhal, A.K. (2004). "Overview of short-distance oil displacement process". *J. Can. Pet. Technol.* 43 (2), pp 29-37.

Vafaie-Sefti, M.^a, and Mousavi-Dehghani, S.A.^a. (2006). "Application of association theory to the prediction of asphaltene deposition: Deposition due to natural depletion and miscible gas injection processes in petroleum reservoirs". ^aDepartment Of Chemical Engineering, Tarbiat Modarres University, P.O. Box 14155-4838, Tehran, Iran.

Vafaie-Sefti Mohsen^a, Mousavi-Dehghani Seyyed, A.^a, and Mohammad-Zadeh Mohammad^b. (2002). "A simple model for asphaltene deposition in petroleum mixtures". ^aDepartment of Chemical Engineering, Tarbiat Modarres University, P.O. Box 14155-4838, Tehran, Iran and ^bNIOC-RIPI, PVT Group, Rey City, Tehran, Iran.

Yang, C., and Gu, Y. (2006). "Diffusion coefficient and oil swelling factors of carbon dioxide, methane, ethane, propane, and mixtures in heavy oil, *Fluid Phase Equilibria* 243, pp 64-73.

Yang Chaodong, and Gu Yongan. (2006). "Diffusion coefficient and oil swelling factors of carbon dioxide, methane, ethane, propane and mixture in heavy oil". Petroleum Technology Research Centre (PTRC), Faculty of Engineering, University of Regina, Regina, Saskatchewan, Canada S4S 0A2.

Zhang, Y. P., Hyndman, C.L., and Maini, B.B. (2000). "Measurement of gas diffusivity in heavy oils". The Department of Chemical and Petroleum Engineering, The University of Calgary, 2500 University Drive NW, Calgary, Alberta, Canada T2N 1N4

APPENDIX – B

Sixth LACCEI International Latin American and Caribbean Conference for Engineering and Technology (LACCEI'2008) "Partnering to Success: Engineering, Education, Research and Development" June 4 – June 6 2008, Tegucigalpa, Honduras.

MATHEMATICAL MODEL OF FLUID INJECTION IN HEAVY OIL RESERVOIRS

Norman D. H. Munroe

Florida International University, Miami, FL, USA, munroen@fiu.edu

Denver F. Cheddie

University of Trinidad & Tobago, denver.cheddie@utt.edu.tt

William Mendez

Florida International University, Miami, FL, USA, wmend002@fiu.edu

Puneet K. Singh Gill

Florida International University, Miami, FL, USA, pgill001@fiu.edu

Abstract

This paper describes the development of a mathematical model of a heavy oil recovery well, where a cylindrically shaped well is assumed. Several variables are considered, which primarily calculate the mass dispersion of an injected gas into oil, and also captures the essential physical phenomena associated with fluid transport and crude oil upgrading. The governing equations for diffusion/convection and Darcy's law are combined forming a partial differential equation system. The diffusion/convection equation represents the propagation of the injected gas fraction along a horizontal axis into a reserve of specific characteristics. Darcy's law drives this dispersion through a vertical reference axis. Molecular diffusion is considered the rate controlling step for absorption of the injected gas in heavy oils. Gas concentration in the heavy oil is dependent on time and distance from the well interface and is a function of its diffusion and dispersion coefficient in the porous medium.

Keywords: Heavy oil, oil sands, injection well, dispersion

Introduction

As conventional world light oil reserves decline, the production of heavy oil resources is predicted to increase significantly in the future. Since there is a dearth of experimental data on the fluid dynamic phenomena inherent in state-of-the-art technologies employed for heavy oil recovery, numerical modeling is one approach to optimize its extraction and the recovery of residual oil (Bravo et al., 2007, Butler et al., 1989a, 2000b, Cuthiell et al., 2003).

Kapadia et al. (2006) developed a model to determine butane dispersion, which is known to have much higher miscibility with heavy oil than CO₂. Due to butane's miscibility with heavy oil, their model assumes perfect miscibility. In reality, CO₂ as the Vapex gas, has a four-stage process whereby mixing takes place Jha, (1986). Thus, it is not feasible to consider these processes in the development of a simple model, since this phenomenon is highly complicated and not sufficiently well understood. However, it can be approximately modeled using an effective diffusion/dispersion coefficient. A lower value of diffusivity essentially means that the miscibility problems slow down the overall mixing and diffusion process. Thus the approach of Kapadia et al (2006) can be modified for CO₂ injection.

A model is currently being developed where a cylindrically shaped well is assumed, whereas, the model developed by Kapadia et al. (2006) assumes a rectangular shaped well. Several variables were considered for the development of this mathematical model, which primarily calculates the mass dispersion of the gas into the oil. Initially the inner surface (or wellbore surface) is saturated with the extraction vapor. This model uses an equilibrium boundary condition, where the saturation

concentration of the Vapex gas is reckoned at equilibrium pressure. The model can be improved by employing a non-equilibrium boundary condition. The Vapex gas then slowly diffuses into the porous oil and mixes with it. Thus, the mass fraction of vapor, ω , increases with time. This reduces the viscosity of the oil allowing it to be extracted. There is bulk flow of the live oil in both the r and z directions due to induced pressure difference and gravity respectively, see Figure 1. In this model, oil is extracted from the sides of the well.

This model entails two components of velocity – horizontal and vertical. The vertical component is affected by gravity only. The horizontal component is caused by the induced pressure difference between injection and extraction. CO_2 is injected at a high pressure, and live oil is extracted at approximately a vacuum. This pressure difference results in a pressure gradient in the radial direction, which results in a horizontal Darcy velocity. As a result, the actual velocity is decreased at some points by the high viscosity of heavy oil. The normal velocity is zero at solid boundaries. It is only non-zero at boundaries where extraction of oil takes place. As oil is extracted, the height of the well decreases with time.

The present model, thus accounts for the molecular distribution of the Vapex gas in the heavy oil, the mixing and the bulk flow of live oil. It also accounts for the variation in well height. However, it can be shown that the time scales for the diffusion of Vapex gas, and the extraction of live oil are vastly different i.e. the well becomes fully saturated with Vapex gas long before the well height begins to decrease significantly. The model can be simplified by working in two stages. The first stage considers the diffusion/dispersion problem with a fixed well height. Once the well becomes fully saturated, the Vapex concentration remains constant at the saturated value. Thus, there is no longer any need to keep solving the dispersion problem. The second stage only deals with the variation in well height with time. This will greatly simplify the model without compromising accuracy. This will also allow COMSOL to be used in the Vapex stage, since it would not have to deal with the moving boundary. This model assumes that the first stage occurs quickly compared to the pumping stage, which has a higher time scale. As a result, the model assumes fixed boundaries during the Vapex process. This further implies that there is no net velocity since the live oil has nowhere to flow until it begins to be pumped out of the well. In reality, when the entire well becomes saturated with the Vapex gas, less than 1% of the oil has been pumped out of the well. So this simplification is advantageous. Therefore, the Vapex process essentially becomes a diffusion/dispersion problem. The pumping problem can now be solved by various techniques, including known correlations. But the Vapex process is the main process of interest.

When steam is used as the Vapex gas, the wellbore surface may not have a constant or consistent steam concentration, because of “bulbs” of steam that form locally. Modeling this requires knowledge of complex multiphase phenomena which is out of the scope of a simplified model. That needs to be addressed in the development of a more complex model.

2. Model Development

Figure 1 illustrates an injection well with cylindrical coordinates and boundary conditions used to develop a simple model in COMSOL. The model represents a porous medium saturated with heavy oil and bitumen within a cubical volume; in this volume a gas injector and recovery well are horizontally placed as practiced in the VAPEX process. The gas is injected and diffuses into the block and gets absorbed by the heavy oil and bitumen. In the development of this mathematical model several assumptions were made (Kapadia et al., 2006):

The Vapex gas exits the well screen at constant temperature and pressure. The oil reservoir has uniform porosity and permeability.

The mass fraction of gas at the exposed surface of porous medium is the saturated mass fraction at equilibrium.

The dispersion of gas proceeds along the r-direction. The transfer of gas along z-direction is governed by the z component of Darcy velocity in the porous medium.

The dispersion of gas incorporates molecular diffusion, the effects of surface renewal and augmentation, and any convective component along the r-direction.

There is no mass transfer across the vertical face of the block on the left hand side at $r = R_i$, which is the wall of the recovery well

Symmetry is assumed in the θ direction, thus allowing for a 2D treatment.

2.1 Equations

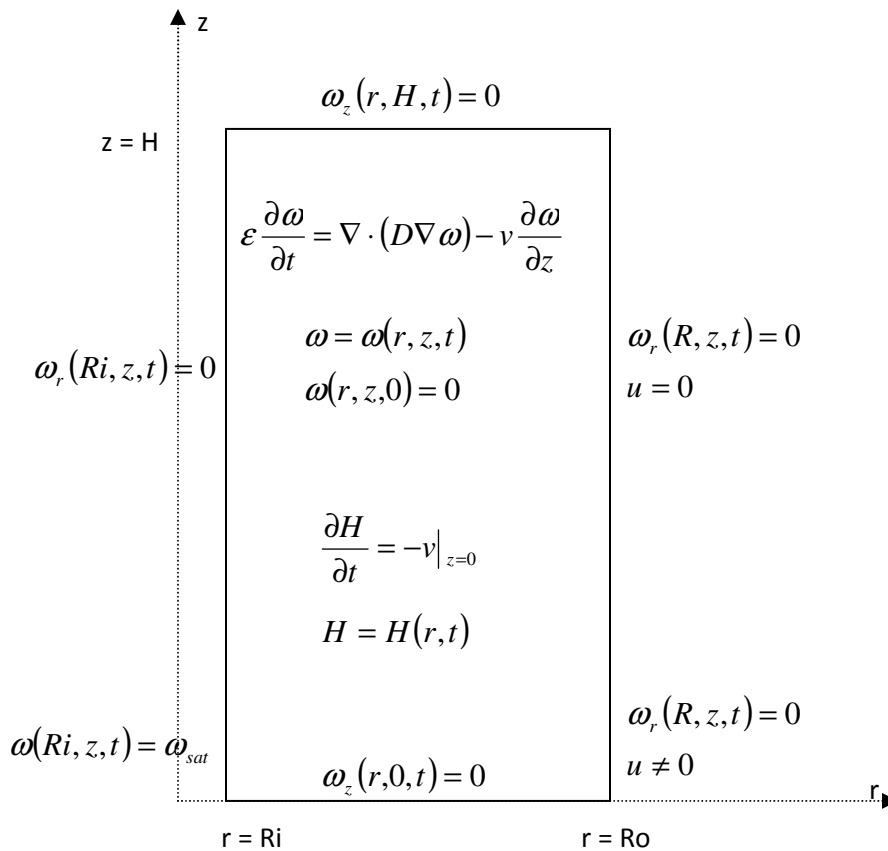


Figure 1: Schematic of cylindrical well (axis-symmetric).

Governing equation used for gas motion dispersion:

$$\epsilon \frac{\partial \omega}{\partial t} = \frac{1}{r} \cdot \frac{\partial}{\partial r} \left(D \cdot r \cdot \frac{\partial \omega}{\partial r} \right) + \frac{\partial}{\partial z} \left(D \cdot \frac{\partial \omega}{\partial z} \right) - v \frac{\partial \omega}{\partial z} \quad (1)$$

Where:

ϕ = Porosity of medium.

ω = Mass fraction of gas in the block.
 \mathcal{D} = Dispersion of the gas along r direction
 v = Darcy's law (represents mass fraction along xdirection).

$$v = \frac{K_r K \rho g \cos \theta}{\mu} \quad (2)$$

Where:

K_r = relative permeability.
 K = relative permeability of gas in the block.
 ρ = density of live oil.
 g = gravity.
 μ = concentration viscosity/ dependency.

Where:

$$\mu = \mu_0 \omega^{-2} \quad (3)$$

For dispersion of gas dependency in heavy oil, we used:

$$\mathcal{D} \propto \mu^{-0.5} \quad (4)$$

From equations (3) and (4) we can derive that the general dispersion dependency is equal:

Where:

$$\mathcal{D} = \mathcal{D}_0 \omega \quad (5)$$

\mathcal{D}_0 = VAPEX gas diffusivity ($\omega = 1$).

These terms which apply to butane gas are defined and assigned numerical values in (Kapadia et al., 2006). These values and correlations have to be adjusted for carbon dioxide and other gases.

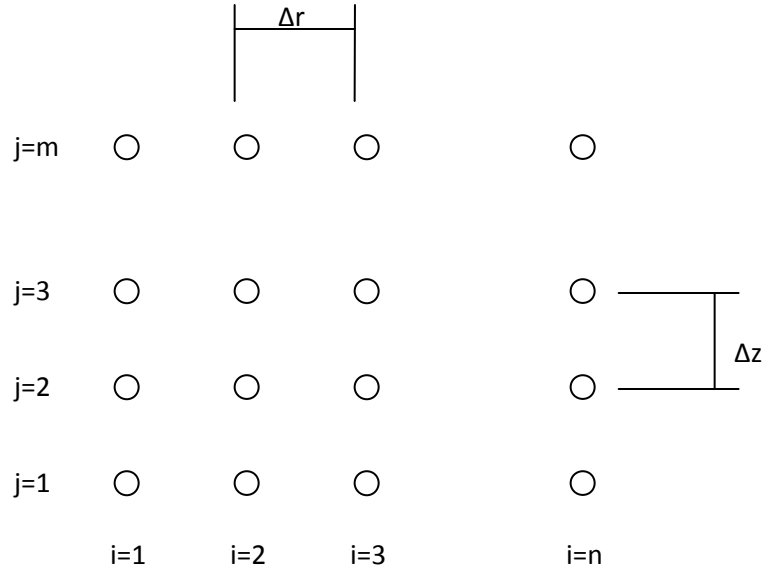
Since most injection wells are cylindrical, our model was adapted to cylindrical coordinates, where the governing equation becomes:

$$\varepsilon \frac{\partial \omega}{\partial t} = \frac{1}{r} \cdot \frac{\partial}{\partial r} \left(D \cdot r \cdot \frac{\partial \omega}{\partial r} \right) + \frac{\partial}{\partial z} \left(D \cdot \frac{\partial \omega}{\partial z} \right) - v \frac{\partial \omega}{\partial z} \quad (6)$$

$$= \frac{1}{r} \cdot \frac{\partial}{\partial r} \left(D_0 \omega \cdot r \cdot \frac{\partial \omega}{\partial r} \right) + \frac{\partial}{\partial z} \left(D_0 \omega \cdot \frac{\partial \omega}{\partial z} \right) - v_0 \omega \frac{\partial \omega}{\partial z} \quad (7)$$

$$= D_0 \left[\omega \frac{\partial^2 \omega}{\partial r^2} + \left(\frac{\partial \omega}{\partial r} \right)^2 + \frac{\omega \partial \omega}{r \partial r} + \omega \frac{\partial^2 \omega}{\partial z^2} + \left(\frac{\partial \omega}{\partial z} \right)^2 \right] - v_0 \omega \frac{\partial \omega}{\partial z} \quad (8)$$

The domain is discretized into equally spaced nodes



$$\frac{\partial \omega}{\partial t}(i, j) = \frac{\omega_{new}(i, j) - \omega(i, j)}{\Delta t}$$

$$\frac{\partial \omega}{\partial r}(i, j) = \frac{\omega(i+1, j) - \omega(i-1, j)}{2\Delta r}$$

$$\frac{\partial^2 \omega}{\partial r^2}(i, j) = \frac{\omega(i+1, j) + \omega(i-1, j) - 2\omega(i, j)}{\Delta r^2}$$

$$\frac{\partial \omega}{\partial z}(i, j) = \frac{\omega(i, j+1) - \omega(i, j-1)}{2\Delta z}$$

$$\frac{\partial^2 \omega}{\partial z^2}(i, j) = \frac{\omega(i, j+1) + \omega(i, j-1) - 2\omega(i, j)}{\Delta z^2}$$

2.2 Boundary Conditions

Boundary value problems in mathematical model development are established by a set of partial differential equations that are governed by restraining boundary conditions (Polyanin and Zaitsev, 2003, Polyanin, 2002). Furthermore, this set of equations must satisfy the boundary values given at each domain. For multi-domain modeling, all boundary conditions must be stated at each sub-domain boundary and interface. For this model the initial boundary conditions are established as follows:

Primarily, there is only gas at the right vertical side of the block; this value of gas concentration is given by the initial states of pressure and temperature of the media (Kapadia et al., 2006). Therefore, the values of concentration at $t = 0$ are:

$$\omega = \begin{cases} 0, & \text{for } 0 \leq z < z_0, 0 \leq r < r_0, \\ \omega_{sat}, & \text{for } 0 < z < z_0, r = r_0 \\ Z = z_0 \end{cases}$$

At $t > 0$ the entire block is exposed to the gas injection; the boundary conditions are established as:

$$\omega = \omega_{\text{sat}} \quad \left\{ \begin{array}{l} \text{for } 0 \leq z \leq Z, r = R_0; \\ \text{for } 0 \leq r < R_0, z = Z_0; \end{array} \right.$$

$$\frac{\partial \omega}{\partial x} = 0; \quad \text{for } 0 \leq z \leq Z \text{ and } r = R_i;$$

2.3 Solution of Algorithm

Fig. 3 shows the general solution algorithm used. Once the governing equations are established a numerical method is used to approximate a result that satisfies the initial and boundary conditions stated at each sub-domain of the model. Firstly, Fig. 1 shows the initial values of gas concentration for this propagation diffusion problem, and secondly new values of concentration are calculated at each grid node within this range.

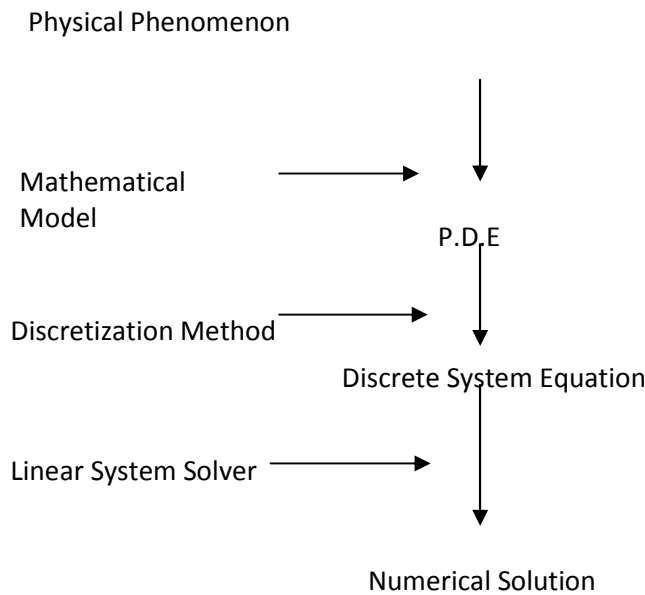


Figure 3: Schematic Algorithm

Numerical Values

Table 1 lists the numerical values used in the computation of the model. In order to predict the diffusion behavior of different gases in heavy oil environments, some of these parameters can be easily modified as needed.

Table 1: Numerical Values used in the computation (Kapadia et al., 2006).

Parameters	Value	Units
Gravity (g)	9.81	m/s ²
Relative permeability (K _r)	1	
Permeability (K)	1.34 x 10 ⁻¹²	m ²
Density (ρ)	850	Kg/m ³
Angle of injection (θ)	π/4	Radians
Viscosity (μ _o)	5.4709 x 10 ⁻⁴	Kg/m.s
Concentration (ω _{sat})	0.87	m ² /s
Porosity (ε)	0.38	
Diffusion coefficient (D _o)	5.56 x 10 ⁻⁵	

3. Results and Discussion

This mathematical model is based upon the behavior of a gas diffusing into a heavy oil and bitumen environment. The solution at several points of the sub-domain symbolizes the values of CO₂ concentration in a cubical domain where the gas is being injected. Because of the simplifying assumptions made earlier we were able to implement this model for a horizontal well-bore into the multi-physics software, COMSOL. The chemical engineering module of this program is capable of generating a solution using a finite element mesh method and solutions can be presented as discrete values in a three dimensional form as shown in Fig. 6.

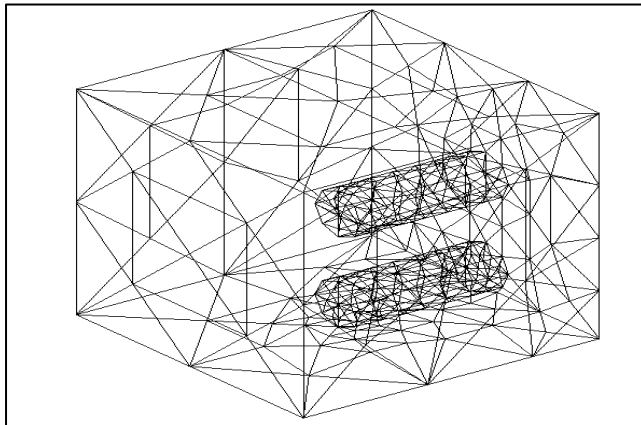


Figure 6: Mesh representation of domain

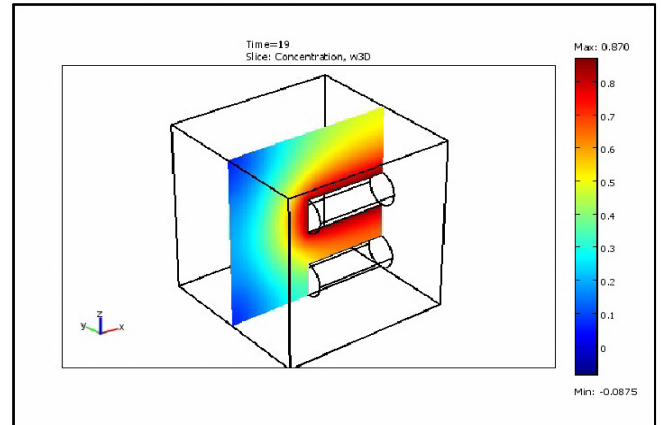


Figure 7: Domain concentration of CO₂ after 19 seconds.

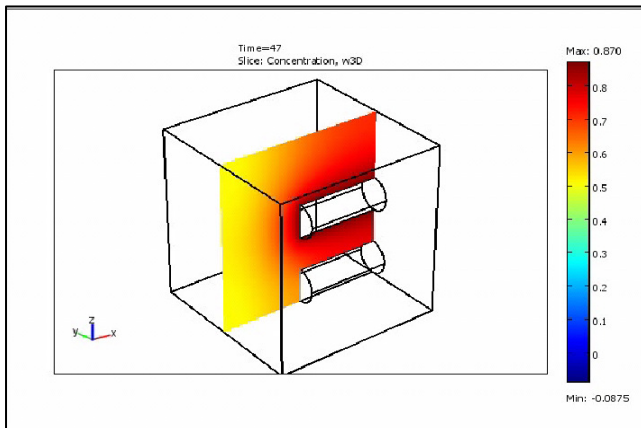


Figure 8: Domain concentration of CO₂ after 47 seconds.

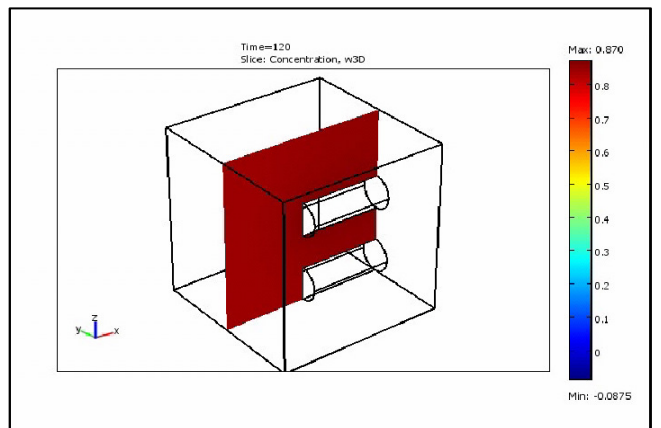


Figure 9: Domain concentration of CO₂ has reached steady state after 120 seconds

Figures 7, 8 and 9 illustrate cross-sections of CO₂ concentrations as a function of time; the minimum value given as -0.0875 represents a small margin of error due to the selected mesh size. The concentration of CO₂ as it approaches a steady state at any chosen location (Arc-length) within the domain is shown in Fig. 10.

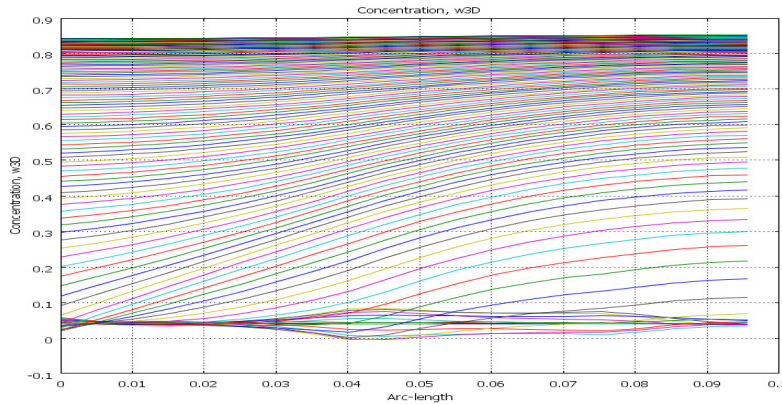


Figure 10: Concentration of CO₂ at a specific Arc- length of the sub domain as it reaches a steady state

4. Conclusion

A mathematical model was developed to simulate the dispersion and concentration of an injected gas into a homogeneous, porous heavy oil reservoir at a specific temperature and pressure. Several assumptions were made in the development of the model to represent the composition of the heavy oil and bitumen as well as to establish the behavior of the gas dispersion. The moving boundaries were also considered with respect to time in the development of this model. Some assumptions regarding boundary conditions were based on published results from other researchers using various gases. Additionally, cross-sections of gas concentrations are presented as a function of time. Finally, a post-analysis process has been developed, which enables the evaluation of the diffusion process up to a stage where the gas concentration reaches a steady state condition throughout the domain.

References

- Akin Serhat and Bagci Suat. (2001). "A laboratory study of single-well steam-assisted gravity drainage process". Petroleum and Natural Gas Engineering Department, Middle East Technical University, Inonu Bulvari 06531, Ankara, Turkey.
- Barillas, J.L.M.^a, Dutra, T.V, Jr.^a and Mata, W.^b. (2006). "Reservoir and operational parameters influence in SAGD process". ^aUniversidade Federal do Rio Grande do Norte, Departamento de Engenharia Química — CT — Campus Universitário UFRN, Lagoa Nova, Natal/RN — CEP: 59078-970, Brazil and ^bUniversidade Federal do Rio Grande do Norte, Departamento de Engenharia Elétrica — CT — Campus Universitário UFRN, Lagoa Nova, Natal/RN — CEP: 59078-970, Brazil.
- Boustani, A., and Maini, B.B. (2001). "The role of diffusion and convective dispersion in vapor extraction process". J. Can. Pet. Technol. 40 (4), pp 68-77.
- Bravo, M.C., Araujo, M. and Lago, M.E. (2007). "Pore network modeling of two-phase flow in a liquid-(disconnected) gas system". Physica A 375, pp 1-17.
- Butler, R.M., and Mokrys, I.J. (1989 - a). "Solvent analog model of steam-assisted gravity drainage". AOSTRA J. Res. 5, pp 17-32.
- Butler, R.M., and Jiang, Q. (2000 - b). "Improved recovery of heavy oil by VAPEX with widely spaced horizontal injectors and producers". J. Can. Pet. Technol. 39 (1), pp 48-56.

Campbell, B.T. (1983). "Flow Visualization of CO₂-Crude Oil Mixtures", Master Thesis, Department of Petroleum and Natural Gas Engineering, New Mexico Institute of Mining and Technology, Socorro, New Mexico.

Canbolat, S.^a, Akin, S.^a, and Kavscek, A.R.^b (2004). "Noncondensable gas steam-assisted gravity drainage". ^aPetroleum and Natural Gas Engineering Department, Middle East Technical University, 06531, Ankara, Turkey and ^bDepartment of Petroleum Engineering, Stanford University, Stanford, CA 94305-2220, USA.

Cuthiell, D., McCarthy, C. Frauenfeld, T, Cameron, S., and Kissel, G. (2003). "Investigation of the VAPEX process using CT scanning and numerical simulation". J. Can. Pet. Technol. 42 (2), pp 41-48.

Das, S.K., and Butler, R.M. (1996). "Diffusion coefficients of propane and butane in Peace River bitumen". Can. J. Chem. Eng. 74, pp 985-992.

Das, S.K. Butler, R.M. "Mechanism of the vapor extraction process for heavy oil and bitumen". J. Pet. Sci. Eng. 21, pp 43-59.

Das Swapan K., and Butler Roger M. (1998). "Mechanism of the vapor extraction process for heavy oil and bitumen". Department of Chemical and Petroleum Engineering, The University of Calgary, Calgary, AB, Canada T2N 1N4.

Emberley, S.^a, Hutcheon, I.^b, Shevalier, M.^b, Durocher, K.^b, Gunter, W.D.^c, and Perkins, E.H.^c (2004). "Geochemical monitoring of fluid-rock interaction and CO₂ storage at the Weyburn CO₂-injection enhanced oil recovery site, Saskatchewan, Canada". ^aEn Cana Corporation, 421 7th Avenue SW, P.O. Box 2850, Calgary, AB, T2P 2S5, Canada, ^bDepartment of Geology and Geophysics, University of Calgary, 2500 University Drive NW, Calgary, AB, T2N 1N4, Canada ^cAlberta Research Council, Edmonton, AB, T6N 1E4, Canada.

James, M.L., Smith, G. M. and Wolford, J.C. (1993). "Applied Numerical Methods for Digital Computation". Harper Collins College Publishers, pp 600,613 and 614.

Jha, K. N. (1986). "A lab study of heavy oil recovery with carbon dioxide". J. of Canadian Petroleum Technology, pp 54-63.

Kapadia A. Ronak^a, Upreti R. Simant^a, Lohi Ali ^{a,b} and Chatzis Ioannis^b. (2006). "Determination of gas dispersion in vapor extraction of heavy oil and bitumen". ^aDepartment of Chemical Engineering, Ryerson University, Toronto, Ontario, Canada M5B 2K3, ^bDepartment of Chemical Engineering, University of Waterloo, Waterloo, Ontario, Canada N2L 3G1.

Luhning, R.W., Das, S.K., Fisher, L.J., Bakker, J., Grabowski, J., Engleman, J.R., Wong, S., Sullivan, L.A., and Boyle, H.A. (2003). "Full scale VAPEX process-climate change advantage and economic consequences". J. Can. Pet. Technol. 42 (2), pp 29-33.

Moulu, J. C. (1989). "Solution gas drive: Experiments and simulation". Petroleum Science and Engineering, 2, pp 379-386.

Nabipour, M.^a, Escrochi, M.^a, Ayatollahi, S.^{a, b}, Boukadi, F.^c, Wadhahi, F.^b, Maamari, R.^b, and Bemani, A. (2006). "Laboratory investigation of thermally-assisted gas-oil gravity drainage for secondary and tertiary oil recovery in fractured models". ^aCollege of petroleum and Chemical Engineering, Shiraz University, Shiraz, Iran, ^bDepartment of Petroleum and Chemical Engineering, College of Engineering, Sultan Qaboos University, Al-Khod, Oman and ^cThe Petroleum Institute, P.O. Box 2533 Abu-Dhabi, United Arab Emirates.

Nestor V. Queipo, Javier V. Goicochea and Salvador Pintos. (2002). "Surrogate modeling-based optimization of SAGD processes". Applied Computing Institute, Faculty of Engineering, University of Zulia, Zulia, Venezuela.

Nghiem, L.X., and Kohse, B.F., Sammon, P.H. (2001). "Compositional simulation of the VAPEX process". J. Can Pet. Technol. 40 (8), pp 54-61.

Polyanin, A. D. and Zaitsev, V. F., Handbook of Exact Solutions for Ordinary Differential Equations (2nd edition), Chapman & Hall/CRC Press, Boca Raton, 2003. ISBN 1-58488-297-2.

Polyanin, A. D., Handbook of Linear Partial Differential Equations for Engineers and Scientists, Chapman & Hall/CRC Press, Boca Raton, 2002. ISBN.

Shapira Yai. (2006). "Solving PDEs in C++: Numerical Methods in a Unified Object-Oriented Approach" Published SIAM, ISBN:0898716012, pp 181-185.

Srivastava, R.K., and Huang, S.S. (1994). "Heavy oil recovery by subcritical carbon dioxide flooding". III Latin American/Caribbean Petroleum Engineering Conference, Buenos Aires, Argentina, pp 27-29, April (SPE#27058).

Tang, G-Q, and Firoozabadi, A. (2003). "Gas and liquid phase relative permeabilities for cold production from heavy oil reservoirs". SPE Reservoir Evaluation & Engineering, pp 70-80.

Vafaie-Sefti, M.^a, and Mousavi-Dehghani, S.A.^a. (2006). "Application of association theory to the prediction of asphaltene deposition: Deposition due to natural depletion and miscible gas injection processes in petroleum reservoirs". ^aDepartment Of Chemical Engineering, Tarbiat Modarres University, P.O. Box 14155-4838, Tehran, Iran.

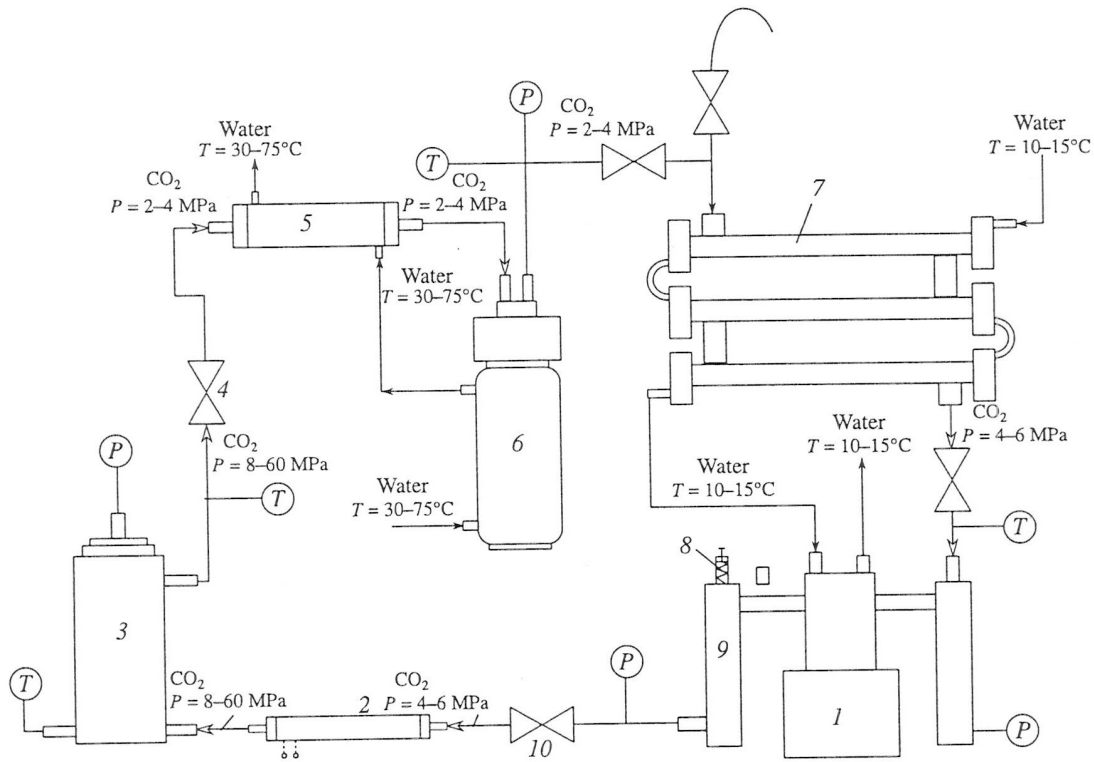
Yang Chaodong, and Gu Yongan. (2006). "Diffusion coefficient and oil swelling factors of carbon dioxide, methane, ethane, propane and mixture in heavy oil". Petroleum Technology Research Centre (PTRC), Faculty of Engineering, University of Regina, Regina, Saskatchewan, Canada S4S 0A2.

Zhang, Y. P., Hyndman, C.L., and Maini, B.B. (2000). "Measurement of gas diffusivity in heavy oils". The Department of Chemical and Petroleum Engineering, The University of Calgary, 2500 University Drive NW, Calgary, Alberta, Ca.

APPENDIX – C (SAMPLE CRUDE ASSAY)

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	Crude
Cut Range	C1-C5	C6-166	155	185	210	335	380	450	510	580	635	725	785	830	900	970	1050	1125	
Yield	0	0	0	0	0.26	0.3	1.21	2.16	4.01	3.87	7.4	5.63	4.68	8.33	7.22	7.26	7.01	40.67	100
Gravity	0.5734	0.6827	0.7151	0.7325	0.8268	0.8486	0.8628	0.8814	0.9018	0.9196	0.9494	0.9708	0.9754	0.9856	0.9972	1.0092	1.0238	1.0858	1.0164
API	115.3	75.8	66.4	61.7	39.6	35.2	32.5	29	25.4	22.4	17.5	14.3	13.6	12.1	10.4	8.7	6.7	-1.2	7.7154
S	0.07	0.07	0.06	0.053	1.444	1.244	1.224	1.54	1.989	2.438	33.19	3.709	3.739	3.741	3.808	4.046	4.665	6.659	5
Acid Number						0.31	0.2	0.4	0.94	2.19	2.5	2.68	2.97	3.33	3.09	3.09	3.5243	3.01222	2.7
N								0.012	0.016	0.026	0.07	0.11	0.13	0.17	0.21	0.26	0.35	0.55	0.32
Bromine										5	8.7	8.7	9.8	11.4					
V																			
Ni																			
Asphaltenes																			
Fe																			
															0.7	1.5	4.4	19.5	30.2

APPENDIX – D (SCHEMATIC OF AN EXPERIMENTAL SETUP FOR EXTRACTION WITH SUPERCRITICAL CARBON DIOXIDE) SAMPLE CRUDE ASSAY



Schematic of an experimental setup for extraction with supercritical carbon dioxide: (1) high-pressure plunger pump, (2) evaporator, (3) extractor, (4) throttle valve, (5) heater, (6) separator, (7) condenser assembly, (8) control valve, (9) buffer vessel, and (10) multipurpose valve.

National Energy Technology Laboratory

626 Cochrans Mill Road
P.O. Box 10940
Pittsburgh, PA 15236-0940

3610 Collins Ferry Road
P.O. Box 880
Morgantown, WV 26507-0880

One West Third Street, Suite 1400
Tulsa, OK 74103-3519

1450 Queen Avenue SW
Albany, OR 97321-2198

2175 University Ave. South
Suite 201
Fairbanks, AK 99709

Visit the NETL website at:
www.netl.doe.gov

Customer Service:
1-800-553-7681

