



DEVELOPMENT OF A COMPUTATIONAL METHOD  
TO ESTIMATE FLUID FLOW RATE IN OIL WELLS  
WITH AN ELECTRICAL SUBMERSIBLE PUMP

BY

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## ABSTRACT

A significant challenge in the oil and gas industry is the simultaneous measurement of commingled gas, oil and water streams, using the three phase test separator or multiphase flow meter (MPFM). The major issue in the application of using either test separator or MPFM in oil field is the uncertainty of the measurements, due to different process and operations conditions. To date, there are no sets of rules proving the technique for comparison between the test separator and the multiphase flow meter. Hence, there is a need for more accurate and reliable methods to be adapted as alternatives to the current flow rate measurements techniques, which must be capable of working at any fluid composition and production flow environment conditions. At first, this thesis will show, through an experimental study, wide variations of the liquid rate measurements between the conventional test separator and MPFM at several periods of time. Then, it proposes a new computational method to estimate the electrical submersible pump (ESP) oil well flow rates. The research idea is to close the wellhead wing valve as the ESP is kept running normally, and the wellhead flowing pressure before well shut-in and the build-up of wellhead flowing pressure after the well shut-in is measured. The total shut-in time period is recorded, and it is dependent on the individual oil well production conditions. Explicit physics concepts for estimations of the multiphase fluid flow rate in a vertical pipe were employed. The formulas deal with changes of fluid flow parameters along the vertical pipe in the well, as a function of pressure and temperature variations with depth. A Microsoft visual basic program was also developed based on the oil mechanistic and empirical equations that can estimate oil rate for ESP oil wells. The new method was applied on 48 ESP oil wells in North African oil fields and lead to very reliable estimation results, which have about a +/-10% relative error. As a result, a regression correlation equation was developed based on the computational results. OLGA software has been used to make comparison with multiphase flow model available in the OLGA software against each nominated ESP oil well parameters obtained from measured field data. The objective was to verify the obtained shut-in wellhead pressure after closing the choke wing valve (WHPa) from the measured field data with the obtained shut-in wellhead pressure valve from the simulation model. The simulation results showed that the estimated WHPa are in agreement with the measured WHPa. The relative errors for individual oil field are within accuracy standard specification (typically +/- 5%). The overall relative errors are low and within acceptable uncertainty range, where the aggregate relative error for all wells was less than +/-4%. Therefore, the results have demonstrated that the new computational method can be applied to all fluid types and under any production conditions. Generally, the results show that the new computational approach is more accurate when compared with test separator measurement within the specified range of accuracy.

## خلاصة البحث

التحدي الكبير في صناعة النفط والغاز هو عملية القياس المتزامنة لتدفق الغاز والنفط والمياه في آن واحد، وذلك باستخدام محطة العزل للسوائل المنتجة (Test Separator) أو باستخدام عدادات ذات خاصية قياس التدفق للسوائل المتعددة (MPFM). هناك العديد من عدادات قياس السوائل التي تم تطويرها منذ مطلع سنة 1980م بواسطة مراكز الأبحاث والشركات المنتجة للنفط والغاز. هناك بعض الدراسات التي أظهرت نتائجها اختلافاً كبيراً في نتائج قياسات السوائل ما بين الطريقتين على فترات زمنية مختلفة. إلى اليوم لا توجد قواعد أساسية لضبط عملية المقارنة بين النظامين، لذلك دعت الحاجة إلى ضرورة إيجاد طرق أكثر اعتماداً ودقةً لحساب تدفق السوائل المنتجة. هذه الأطروحة تقترح طريقة حسابية جديدة لتحديد معدل تدفق إنتاج النفط من الآبار التي تعمل باستخدام المضخة الكهربائية الغاطسة (ESP). فكرة البحث تعتمد أساساً على غلق صمام رأس البئر النفطي مع ترك المضخة تعمل بصورة طبيعية ويتم قياس ضغط رأس البئر ( $WHP_b$ ) قبل قفل الصمام أثناء عملية الإنتاج وبعد قفل الصمام ( $WHP_a$ )، (على الأقل يزداد ضغط رأس البئر 50 رطل أخرى عن ضغط رأس البئر قبل القفل)، وتسجيل الفترة الزمنية الكلية لعملية قفل الصمام. تم استخدام المعادلات الفيزيائية والمعادلات العملية اللازمة في حسابات خصائص السوائل المتدفقة عند حدوث أي تغير في الضغط ودرجة الحرارة على طول عمق البئر العمودي. في هذا الأطروحة أيضاً تم استخدام برنامج مايكروسوفت (Visual Basic) لبناء العمليات الحسابية للطريقة الجديدة. الطريقة طبقت على عدد 48 بئر نفطي يستخدم المضخة الكهربائية الغاطسة لحقول نفط في شمال أفريقيا. الطريقة الجديدة أظهرت نسبة الخطأ النسبي حوالي  $+/-10\%$ . ونتيجة لذلك، تم تطوير معادلة الأنحدار على أساس النتائج الحسابية المتحصل عليها. هذا البحث استخدم أيضاً برنامج النمذج الرياضي (OLGA) وذلك لحساب ضغط صمام رأس البئر أثناء القفل ( $WHP_a$ ) المتحصل عليها من النمذج الرياضي ومقارنته مع ضغط قفل صمام رأس البئر المتحصل عليها من القياسات الحقلية لكل بئر. النتائج كانت جيدة أيضاً حيث أن نسبة الخطأ النسبي كانت  $+/-5\%$  لكل بئر. وبالنظر إلى الخطأ النسبي لجميع الآبار مجتمعة كانت حوالي  $4\%$ . لذا اعتبرت دقة نتائج التي أظهرتها الطريقة الحسابية الجديدة مقبولة ويمكن الاعتماد عليها كطريقة جديدة يمكن تطبيقها على جميع الآبار التي تستعمل المضخة الكهربائية الغاطسة وتحت أي ظروف عملية و إنتاجية.

## **APPROVAL PAGE**

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## DECLARATION

I hereby declare that this dissertation is the result of my own investigations, except where otherwise stated. I also declare that it has not been previously or concurrently submitted as a whole for any other degrees at IIUM or other institutions.

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## LIST OF ABBREVIATIONS

|          |  |
|----------|--|
| API      | Oil specific gravity   |
| A        | Pipe cross-sectional area, sq ft   |
| $B_g$    | Gas formation vol. Factor, res. cf/scf                                     |
| $B_o$    | Oil formation vol. Factor, res. bbl/stb                                    |
| Bob      | Oil formation volume at bubble point pressure, bbl/STB                     |
| Cnt      | Count  |
| d        | Inside pipe diameter, ft   |
| $dp/dz$  | Total pressure gradient (friction pressure loss is considered).            |
| f        | Friction losses factor   |
| FVF      | Formation Volume Factor  |
| g        | Gravity  |
| HG       | Gas holdup   |
| HL       | Liquid holdup  |
| H1       | Bubble point pressure location depth before closing the wellhead valve, ft |
| H2       | Bubble point pressure location depth after closing the wellhead valve, ft  |
| mt       | Mass flow rate, lb/day   |
| $N_{Lv}$ | Liquid velocity number   |
| $N_{gv}$ | Gas velocity number  |
| NL       | Liquid viscosity number  |
| Nd       | Pipe diameter number   |
| NCL      | Correction for viscosity number coefficient                                |
| $q_o$    | Oil flow rate stb/day  |

|          |   |
|----------|---|
| $q_w$    | Water flow rate stb/day                             |
| $q_g$    | Gas flow rate stb/day                               |
| $q_L$    | Liquid flow rate stb/day                            |
| $q_m$    | Measured flow rate stb/day                          |
| QC       | Quality Check                                       |
| P        | Average pressure, psia                              |
| $P_b$    | Bubble point pressure, psia                         |
| $P_r$    | Pseudo-critical pressure of gas mixture, psia       |
| $P_{sc}$ | Pressure at standard conditions, psia               |
| PSD      | Pump setting depth                                  |
| SGG      | Specific gravity of gas                             |
| STB      | Stock tank barrel                                   |
| $r_w$    | Wellbore radius, ft                                 |
| $R_s$    | Solution gas-oil ratio, scf/stb                     |
| $R_{sb}$ | Solution gas at bubble point pressure, (cf/scf)     |
| $Re$     | Reynolds number                                     |
| T        | Average temperature, °F                             |
| t        | Shut-in time, min                                   |
| $T_r$    | Pseudo-critical temperature of gas mixture, psia    |
| $T_{sc}$ | Temperature at standard condition, °R               |
| $T_r$    | Reservoir temperature, °F                           |
| VR       | Gas volume at down-hole conditions, ft <sup>3</sup> |
| $V_{sc}$ | Gas volume at standard condition, ft <sup>3</sup>   |
| $VS_L$   | Superficial liquid velocity, ft/sec                 |
| $VS_g$   | Superficial gas velocity, ft/sec                    |
| $V_m$    | Mixture velocity, ft/sec                            |

|                  |   |
|------------------|---|
| WHP <sub>a</sub> | Wellhead pressure after closing the well, psia  |
| WHP <sub>b</sub> | Wellhead pressure before closing the well, psia |
| WC               | Water cut (non-dimensional)                     |
| WHT              | Wellhead temperature, °F                        |
| W                | Water vapour density                            |
| Z                | Gas compressibility factor                      |

## LIST OF SYMBOLS

|            |  |
|------------|--|
| $\Delta P$ | Drawdown pressure, psia  |
| $HL/\psi$  | Holdup factor correlation  |
| $\gamma_o$ | Oil gravity  |
| $\gamma_w$ | Water gravity  |
| $\gamma_g$ | Gas gravity  |
| $\sigma$   | Surface Tension  |
| $\Delta H$ | The differences between bubble point pressure location depth before and after closing the wellhead valve, ft |
| $\rho_o$   | Oil density lbm/ cu ft   |
| $\rho_g$   | Gas density lbm/ cu ft   |
| $\rho_w$   | Water density lbm/ cu ft   |
| $\rho_L$   | Liquid density, lb/cu ft   |
| $\rho_m$   | Mixture density, lbm/ cu ft  |
| $\mu_o$    | Oil viscosity, cp.   |
| $\mu_g$    | Gas viscosity, cp.   |
| $\mu_L$    | Liquid viscosity, cp   |
| Subscripts |  |
| $g_s$      | Gas at standard condition  |
| $h$        | Hydrostatic  |
| $L$        | Liquid   |
| $m$        | Mixture of liquid and gas  |

|    |                    |
|----|--------------------|
| o  | Oil                |
| sc | Standard condition |
| w  | Water              |

# **CHAPTER ONE**

## **INTRODUCTION**

### **1.1 MULTIPHASE FLOW MEASUREMENTS**

The problem of how to meter oil-water-gas mixtures has been of interest to the petroleum industry since the early 1980's. A number of such meters have been developed by research organizations, manufacturers, oil and gas production companies, and other interested parties (Benlizidia, 2009). Different technologies and various combinations of technologies have been employed to produce prototypes which are dissimilar in form and function. While some lines of development have been abandoned, a number of meters have become commercially available, and the number of applications and users is rapidly increasing (Corneliussen et al., 2005). Gas/oil flow rate of production well is an important parameter for evaluating oilfield production (Nian, 2015). Oil producers used three-phase test separators or Multiphase Flow Meters (MPFM) to measure the total volume of fluids produced by individual wells in a large upstream production field.

Traditionally, metering of the multiphase flow is carried out by utilizing two or three phase test separators using single-phase flow meters installed at the outlets of the oil, water and gas legs. These have an acceptable accuracy limit, depending on operator's skills, maintenance work and various other factors such as fluid properties variation (Hosseini et al., 2011). The test separators are practical and the accuracies acceptable during the early production stages. However, the test separator accuracy is highly dependent on changes in Gas Oil Ratio (GOR) and Water Cut (WC) which yield to changes in the flow regime and fluid characteristics. Besides, test separators are expensive, occupy valuable space on a production platform and require a long time to

monitor each well because of the stabilized flow conditions required. In addition, test separators cannot be used for continuous well monitoring.

During the late 1980's, the oil and gas industry started to realize that the availability of multi-phase flow meters could have a large economic impact on the infrastructure of oil and gas developments (Scheers and Wee, 2011). Multiphase flow meters (MPFM), on the other hand, do not rely on separation (100%) of the fluid and operate under various conditions for flow measurement, but these are also considered as unreliable measurement tools at high GOR and high WC. In addition, Multiphase flow meters are also very expensive to install. Hence, there is a need to adopt more accurate and reliable methods as alternatives to the current flow rate measurements techniques, and it must be capable of working in any fluid composition and production flow environment conditions (Falcone et al., 2009). In practice, down-hole measurement devices in the tubing string are not available due to the complication of fluid properties and conditions in terms of multiphase flow (Wee and Skjaeldal, 2009).

This research work proposes a new computational method to estimate the hydrocarbon fluid flow rate of the ESP oil wells. It is based on the estimations of multiphase fluid flow parameter variations along the vertical pipe in an oil well as pressure and temperature changes with depth, using principles of multiphase flow mechanistic equations and empirical correlations. A Microsoft visual basic program was also developed based on the oil mechanistic and empirical equations that can estimate oil rate for ESP oil wells. Besides, OLGA simulation model was used to verify the field input data used with the simulation model results.

### **1.1.1 Research Ground Work**

This research work proposes a new method by which to determine fluid flow rate from the ESP oil well. It is based on the computation of fluid properties variation as a function of pressure and temperature changes with depth, in the vertical well pipe. This method is used in oil wells through an artificial-lift technique such as Electrical Submersible Pump (ESP). A sample of 48 ESP oil wells from G, W, and D oil fields in North Africa were chosen to apply the new approach.

This new method is applied by keeping the oil pump running, and by closing the wellhead pressure wing valve for a few minutes (depending on the individual oil well condition) to build up the wellhead pressure to at least 50 psi. The mechanism of calculation is based on the difference in gas volume at different bubble point pressure location depths, before and after closing the wellhead wing valve. From this incremental buildup of measured pressure, a new method will be developed to compute the hydrocarbon fluid flow of the ESP oil wells. The new method can be applied to different fluid flow composition and flow regime.

The algorithm program was developed using a Microsoft visual basic program (Evangelos, 2008) to estimate the fluid flow of the ESP oil wells through specific algorithm codes. The algorithm program is a diagrammatic representation of the steps used in solving the computational method using multi-physics equations (Keyes et al., 2013) and (Anders, 2015). The program identifies all the major steps and sub-steps in a process. In this algorithm, the initialization step is run to obtain the bubble point pressure location depth, before and after closing the wellhead wing valve. Based on the verification and validation of the new computational approach outputs, a new estimation oil flow rate regression equation was developed. A mathematical procedure for finding the best-fitting curve was used to measure and estimate data points by