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Orifice plate meter field performance: Formulation and validation in multiphase flow conditions

S.R.V. Campos [a,d], J.L. Baliño [b,*], I. Slobodcicov [a], D.F. Filho [c], E.F. Paz [b,1]

[a] Petrobras, Centro de Pesquisas e Desenvolvimento Leopoldo Américo Miguez de Mello, CEP 21941-598, Ilha do Fundão, Cidade Universitária, Rio de Janeiro, RJ, Brazil
[b] Departmento de Engenharia Mecânica, Escola Politécnica, Universidade de São Paulo Av. Prof. Mello Moraes, 2231, CEP 05508-900, Cidade Universitária, São Paulo, SP, Brazil
[c] Petrobras, Unidade de Operações de Exploração e Produção da Amazônia, Rua Darci Vargas, 645, CEP 69050-020, Chapada, Manaus, AM, Brazil
[d] Department of Petroleum Engineering and Applied Geophysics, Norwegian University of Science and Technology, 7491 Trondheim, Norway

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ABSTRACT

The performance of orifice plates in real-time monitoring of oil, gas and water standard flow rates was investigated. To this end, a multi-rate test was implemented in two production wells routed individually to a test separator in field operational conditions. The well flow rate was varied in steps by changing the choke opening.

The ranges of fluid properties and flow conditions achieved during the experiment were: wellhead pressure from 9073 kPa to 13,278 kPa, wellhead temperature from 47.8 °C to 53.5 °C, downstream choke pressure from 6770 kPa to 7913 kPa, downstream choke temperature from 41.6 °C to 49.1 °C, gas–oil-ratio from 1144 Sm^3/Sm^3 to 2068 Sm^3/Sm^3, water-cut from 4.64% to 58.35%, standard oil specific gravity from 0.7988 to 0.8058, standard gas specific gravity from 0.7340 to 0.7550, standard oil flow rate from 46.86 Sm^3/d to 266.65 Sm^3/d, standard gas flow rate from 62.68×10^3 Sm^3/d to 296.65×10^3 Sm^3/d, standard water flow rate from 18.06 m^3/d to 159.33 m^3/d.

The wells tested showed a different dynamic behavior: while well #2 did not vary significantly the stream composition with flow rate, well #1 produced under gas coning, a near well-reservoir phenomenon that governs the contribution of the reservoir gas-cap to the total stream composition.

The multi-rate tests generated two data sets with 1424 flow conditions through two flange-tap orifice plates installed upstream (wellhead) and downstream of a cage choke valve. The ranges of orifice variables were: orifice diameter from 0.03479 m to 0.0430 m, beta factor from 0.4946 to 0.6507, differential pressure from 15 kPa to 187 kPa.

The virtual metering system presented in Paz et al. (2010) was used to correlate the experimental data. The associated model, suitable for differential pressure measuring devices, includes effects such as flow concentration and slip (through Chisholm's correlation), generalizing the mass flow rate versus pressure drop relationship for multiphase flow. The total mass flow rate depends on a set of variables evaluated at metering conditions: density and viscosity of the liquid and gas phase, mass quality, pressure drop across the flow meter and geometry (contraction area and beta factor).

The determination of the fluid properties at metering conditions was made by using black-oil correlations. These correlations are based on a set of input variables at standard condition that characterizes the stream composition such as gas–oil ratio, water–oil ratio and specific gravities of each phase.

A comparison was made between the multiphase flow rates predicted by the model and the ones simultaneously measured at the test separators. The oil, gas and water standard volumetric flow rate deviations (coefficients of variation of the root mean square deviations) were below 3.52%.

It was theoretically demonstrated and experimentally verified that a systematic error exists when the homogeneous model (equal phase velocities) is considered in the formulation, resulting in a flow rate underestimation. When the homogeneous model was used to correlate the data, this effect increased the deviation up to 10.5%.

Flow pattern at the wellhead was characterized as intermittent and annular-mist. Lockhart–Martinelli parameter varied from 0.362 to 0.836; despite of the experimental data being beyond the wet gas region, the multi-rate tests showed that Chisholm's over-reading can be successfully extrapolated to these range.

* Corresponding author. Tel.: +55 11992723660.
E-mail address: jlbalino@usp.br (J.L. Baliño).
[1] Current address: Petrobras Transporte S.A. (Transpetro) Rua Felipe Camarão, 393, CEP 09550-000, Prosperidade, São Caetano do Sul, SP, Brazil.

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1. Introduction

The availability of a system for estimating on real time oil, gas and water standard flow rates coming from each well is of primary importance for field operators. The estimation of multiphase flow rates for production management relies in models based on the wellhead and bottomhole instrumentation.

The installation of multiphase flow meters (MPFM) is a very expensive solution. These devices perform a simultaneous measurement of concentrations to determine the phase flow rates. Ismail et al. [14] presents a table with the techniques used in several commercial MPFM. Usually, MPFM require complex maintenance procedures associated with long downtime periods. Besides, for production optimization applications it is not necessary a high accuracy level in the measurements, but reliability for well surveillance.

Virtual metering systems (VMS) have been developed to provide a simple, robust and low cost alternative for multiphase flow rate estimation. VMS are characterized by the use of normal process variables available in production systems (such as pressures or temperatures) and by the assumption of equilibrium between the phases for a given hydrocarbon composition. The normal process variables are measured online, while the characterization of the fluid is based on a set of variables measured periodically at standard condition. The approach is completed with a model that simulates the flow across the measuring device and a model that predicts the fluid thermodynamic condition (PVT data).

In Faluomi et al. [11] a VMS based on the performance of a choke valve is presented, showing accuracy levels for oil and gas flow rates comparable to the ones typical of multiphase flow meters.

The pressure difference across a reduction in flowing area (such as that exists in venturi, orifice plate or nozzle meters), is one of the most widely employed primary measurements in multiphase flow meters [22]. According to Falcone et al. [10], there is no general relationship for differential pressure across these devices for multiphase flows, being important issues the effective viscosity and the degree to which they are mixed. Additional effects that should be modeled when using differential pressure flow meters in multiphase flow (compared to single-phase flows) are the stream composition and relative velocity between the phases.

Chisholm [4] developed a correlation for the flow of gas–liquid or vapor–liquid mixtures through sharp-edged orifices considering the momentum equation for incompressible liquid and gas phases, neglecting upstream momentum, taking into account the interfacial shear force and assuming the same contraction coefficient for the areas in each phase (equal to the single-phase value). The slip ratio results a function of a "shear force function", which was found to be approximately constant for a particular orifice and pipe geometry over a wide range of gas–liquid density ratios, while the area ratio results equal to the product of the shear force function and the Lockhart–Martinelli parameter. Based on experimental data, Chisholm [5] extended the slip ratio correlation for low quality flows (see Section 3.3).

Kojasov et al. [16] studied the total pressure drop (sudden contraction plus sudden expansion) across orifice plates (thick and thin) and generated a benchmark data base using saturated two-phase R-113 as working fluid. Using the mass, momentum and energy equation, the departure of the slip ratio from Chisholm's correlation was adjusted from the experimental data, resulting pressure drop mean errors between 10.5% and 14.5% for the three different data sets.

Steven and Hall [25] presented results based on combined data sets from various studies of orifice meters in wet gas flow (natural gas or nitrogen as gas phase; decane, Stoddard solvent or Exxsol D80 as liquid phase). By modifying the constant in Chisholm's over-reading correlation (see Section 3.5), making it a function of a gas densimetric Froude number, the gas flow (for a known liquid flow rate) was successfully correlated within an error of 2% at a 95% confidence level. The investigation concluded that measurements using orifice meters operating with wet gas flow are repeatable and reproducible.

Oliveira et al. [20] carried out measurements of two-phase air–water flow variables using a resistive void fraction sensor coupled to a venturi or orifice plate. With the additional measurement of void fraction, the slip ratio and total mass flow rate were calculated by using different correlations, among them the homogeneous model and Chisholm's correlation. It was verified that the homogeneous model underestimates de flow rate prediction for horizontal and vertical orifice plates, but performed better for venturis.

Fischer [12] presented experimental results obtained with a three-phase oil–water–air rig in which a combination of a venturi, a capacitor and a single-beam gamma densitometer was used. It was concluded that the metering system works properly if the phases are well homogenized, with oil or air forming the continuous phase, but further work is needed to cope with actual operating conditions.

The determination of the flow rates in field conditions made through well testing is more difficult than in laboratory conditions, because it is necessary to deal with the real fluids and with particular characteristics of the system, such as the interaction with the reservoir, piping and separator tank. Well testing requires a considerable time to reach a stable flow condition; as a consequence, uncertainties in well testing are considerably higher than the ones associated to the instrumentation alone. The use of a metering device for monitoring on real-time the well production is an alternative that could lower the frequency of well tests needed (usually once a month) and, consequently, operating expenses.

In this paper, the performance of orifice plates in estimating on real time oil, gas and water flow rates was investigated using field data. An experimental campaign was carried out at two different wells located at Urucu field, (Solimões basin, Amazonas, Brazil), where simultaneous measurements of individual flow rates at a test separator were made in order to make a comparison with the flow rates predicted by a VMS based on these differential pressure flow meters.

2. Multi-rate well tests

2.1. Urucu oil field

Urucu oil field is located at the Solimões basin (Amazonas, Brazil). In mature fields, the choice of a virtual metering strategy is defined based on the installed wellhead and bottomhole instrumentation. Although some wells in the field also have PDG (Permanent Downhole Gauges) for downhole pressure and temperature measurements, the possibility of performing topside maintenance is the main driver to use surface input variables to estimate production flow rate in real time.

The crude produced in the field has average oil gravity of 43 *API* and condensate gravity of 60 *API*. Gas–oil ratio *GOR* ranges from 250 Sm^3/Sm^3 in early well life stage to 9000 Sm^3/Sm^3. Gas expansion is the primary reservoir recovery mechanism. The oil saturated interval is a thin oil rim below a large gas cap.

Most of the wells experience gas and water coning. This near wellbore effect was described by Campos et al. [2]. Depending on the influence of bottomhole drawdown in coning geometry, the production stream will have more or less contribution from the gas cap. Gas/water coning is a reservoir phenomenon that modifies the fluid composition in producing stream, affecting the short term management decisions. The Urucu field production is mainly constrained by the LNG (Liquefied Natural Gas) process facility