SPE Brazil Flow Assurance Technology Congress
Rio de Janeiro, Brazil, November 15 – 18 2022

Virtual Flow Metering as a digital solution to production management

Gabriela Chaves[1*], Stian Engebretsen[1]
[1]AspenTech – Subsurface Science & Engineering, [*]gabriela.chaves@aspentech.com

Abstract
The oil and gas industry is undergoing a digital transformation. In the production area, additional equipment is being installed to obtain data and more efforts have been invested in data treatment. However, the industry has not yet fully embraced this new digital era, and it is still lacking proper technology to manage production data. This paper presents a digital technology called VFM (Virtual Flow Metering), which is able to transform data into valuable information to support our industry's digital transformation. A sensitivity analysis concerning the available instrumentation is also presented to investigate its effects and provide a deeper understanding of its impact on the virtual metering technology. The VFM is a powerful web-based application that analyzes real-time sensor measurements to estimate the flow of oil, gas and water. The application is designed to provide an accessible and easy way to monitor production and help engineers in the decision-making process. The production system is modeled and simulated using production modeling software and the VFM estimates the optimal phase flow rates that matches all available measurements using an iterative search method.

Keywords
Virtual Flow Metering; Production Monitoring; Multiphase flow modeling.

Introduction
We are living in a digital era where information is power. The world is focused on improving technology and obtaining maximum from data. We must be aware that data itself may not represent information; similarly, technology alone cannot provide information. Data and technology must be combined wisely to result in valuable information.
To keep up with the digital era, oil and gas companies are increasingly investing in data and technology. In the production area, additional equipment is being installed to obtain data at different production points and more efforts have been invested in data treatment. However, the industry has not yet fully embraced this new digital era, and it is still lacking proper technology to manage production data. In this context, we are presenting a digital technology called VFM (Virtual Flow Metering), which is able to transform data into valuable information to support our industry's digital transformation. We also perform a sensitivity analysis concerning the available instrumentation to investigate its effects and provide a deeper understanding of its impact on the virtual metering technology.
The presented VFM is a powerful web-based application that analyzes real-time sensor measurements to estimate the flow of oil, gas and water. The application delivers predictive results by leveraging physics-based multiphase flow models and optimization algorithms to continuously find the best match between field sensor data and multi-phase flow simulation.
The VFM technology is recognized in the industry as a cost-efficient solution for estimating multiphase flow rates using data from sensors [1, 2, 3, 4]. One of the main benefits of this technology is that no additional hardware is required if the field is equipped with sensors, which is the case in deepwater fields.
An extensive literature review classifies the VFM into two main methods: first principles and data-driven [1]. The first principles method is based on modeling the flow as a physical phenomenon, while the data-driven approach uses collected data to fit a mathematical model. The data-driven approach has increased in the last decade with the development of machine learning techniques. However, the first principles are still the most widely used approach in commercial VFM systems [1], and is the one used in this paper.
Several benefits were reported by companies that implemented VFM systems. The most important of them is that VFM allows monitoring production in real-time, which is the best way to optimize field performance [5] and allocate production [6,7]. VFM monitors production by tracking the flow rates, pressure, temperature, choke valves, flow-related parameters and their trending. Production and reservoir engineers spend more time gathering and manipulating data than they do on analysis and decision-making [8]. An improvement was reported by [8], where the time spent by engineers on gathering and manipulating data decreased, and more time was spent making better decisions with the VFM implementation. Mokhtari and Waltrich (2016) [4] reported VFM as a backup or alternative for multiphase flowmeter devices. Poulisse et al.

(2006) [9] also reported a series of benefits with the real-time production estimation: reduction in the annual declination rate, improvement in the optimization process, improvement in production forecasting, and reduction in well testing. In this case, the tool was also used to estimate when a well needs to be tested again. The flow rate predictions were also used by [10] to capture reservoir pressure declination.
The presented technology was designed to provide all the above benefits using a first principles methodology discussed in the next section.

Methodology

The main structure of the VFM methodology is shown in *Figure 1*. The field data feeds an online server that communicates with a production modeling software and the VFM algorithm. VFM receives this data as measured values. The production modeling software works like a black box to the VFM algorithm, where it only receives and sends calculated values; the simulations are invisible to the VFM algorithm.
The production modeling software used is responsible for continuously modeling integrated production systems, from the reservoir to the production facilities. The software models the fluid, well, flowlines, equipment, injection and artificial lift systems, using the continuous drift-flux approach [11]. The drift-flux model simulates the flow using a mechanistic approach, which returns calculations more loyal to the physics behavior when compared to empirical modeling. The software has features such as model calibration that play a critical role in the VFM results [12] once a calibrated model returns more reliable simulations.

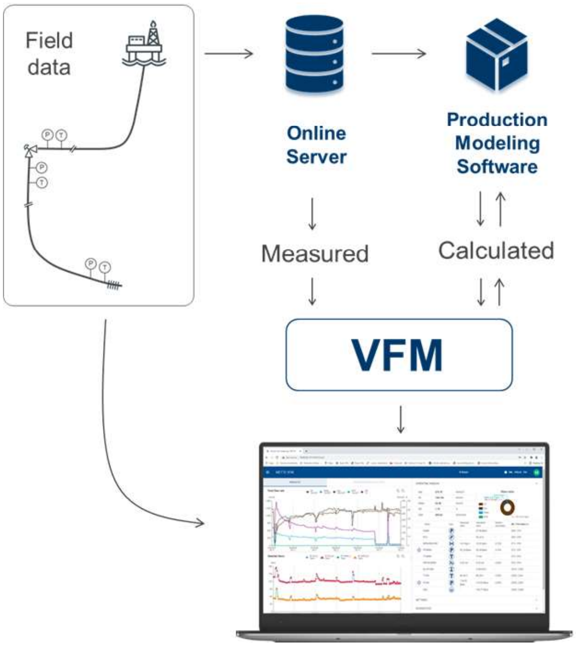

Figure 1- Methodology structure.

The VFM algorithm has an objective function defined in Equation 1:

$$Min \sum_{i,p} w_i \left(\frac{Y_{i,M} - Y_{i,C}(Q)}{Y_{i,M}} \right)^2 \qquad (1)$$

Where the index i is related to each sensor; w_i is the sensor weight; $Y_{i,M}$ is the measured value for each sensor i; $Y_{i,C}$ is the calculated value for each sensor i; and Q is the flow phase.
The algorithm minimizes the objective function using an interactive search method that calculates the optimal flow rates for each phase (oil, gas and water).
The number of available sensor readings and the quality of the data directly impact the results, which are evaluated in the sensitivity analysis. The sensor's weight is a way to control the importance and reliability of the sensors. Lower weights correspond to less influence on the flow estimation. Thus, low-reliability sensors can be assigned to low weights.

Data

Production fields have different layouts and available instrumentation. At the same time, the methodology must handle a wide range of layouts. The required data are separated into two main groups: real-time data and model, as shown in Table 1. The data presented is a typical example. If more data is available, especially from sensors, it can be included in the model to improve accuracy.

Table 1 - Typical data required.

Real-Time Data	Downhole Pressure sensors Downhole Temperature sensors Wellhead Pressure Wellhead Temperature Choke valve opening Artificial lift information (if used)
Well Model	Well trajectory Fluid Composition – PVT tables Equipment specifications Valves specifications Tank models

In cases where an MPFM is available, its data can be collected and the VFM also works as a validation and backup system.

Web App Features

The main purpose of the VFM is to transform data into valuable information for users. The technology includes features that can play a big role in making the engineer's work easier to monitor and supporting the decision-making process. These include:

- Web-based - provides access from any device
- Multiple projects on the same platform
- Individual login
- Role-based login - provides control over who can make changes in the model

- Track the model and user updates through a History Log
- Customizable sensor weights
- New constraints can be set or changed at any time
- Model calibration multipliers can be changed at any time

Study Case

Field data of three wells are considered. Two of them have a gas lift injection system, and one does not. A scheme of the production wells is shown in Figure 2 and the nomenclature is defined in Table 2.

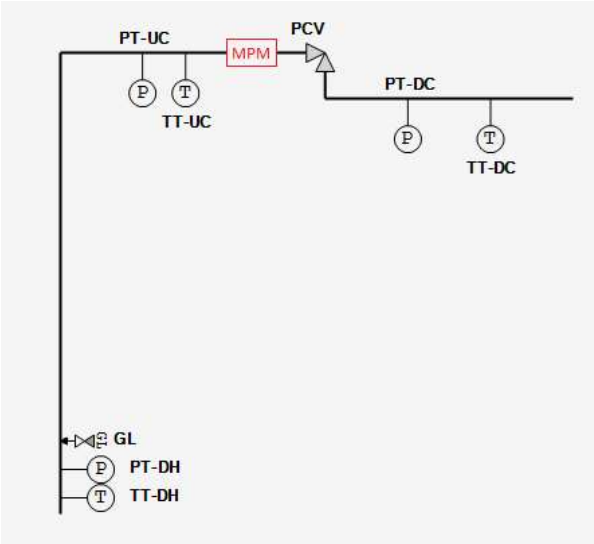

Figure 2- Well scheme

Table 2 – Nomenclature for items.

Nomenclature	Definition
PT	Pressure Transmitter
TT	Temperature Transmitter
GL	Gas Lift Injection
PCV	Choke Valve
DH	Downhole
UC	Upstream Choke
DC	Downstream Choke

The wells have a multiphase flow meter (MPM), which measures in-situ oil, gas and water volumetric flow rates, the mixture density and the water cut (WC). The in-situ flow rates are not used in the VFM algorithm, but they are used to compare the calculated values.
Part of the data is also used to calibrate the model. Calibration is a strategy often used in the industry to incorporate uncertainties that the model is not able to detect, such as reservoir depletion, erosion and solid deposition.
The MPM measurements and the calibration are considered in different scenarios described in the following section.

Sensitivity Analysis

The accuracy of the VFM relies on the available instrumentation and data. A sensitivity analysis was performed to investigate the effect of instrumentation and strategies, such as the model calibration and use of an IPR (Inflow Performance Relationship) to obtain the downhole pressure. The analysis is divided into 6 scenarios described in Table 3. We define the basic input data as the group of measurements: downhole sensors (PT-DH, TT-DH), upstream choke (PT-UC, TT-UC), downstream choke (PT-DC, TT-DC), choke position (PCV), gas lift injection (GL).

Table 3 - Group description

Scenario	Description	Model Calibration
Scenario 1	Basic input data	yes
Scenario 2	Basic input data	no
Scenario 3	Basic input data + the MPM WC	yes
Scenario 4	Basic input data + the MPM Density	yes
Scenario 5	Basic input data + the MPM Density and WC	yes
Scenario 6	Basic input data – replacing PT-DH for IPR	yes

Scenario 1 uses the defined basic input data without the calibration procedure. This scenario evaluates the VFM performance with a basic and usual set of sensor data. Scenario 2 uses the same sensor available in Scenario 1, but with the calibration. Scenario 2 shows how the calibration makes a difference in the VFM performance and the VFM as a standalone tool (without MPM measurements). Scenario 3 updates the WC values to investigate the impact of the WC measurements. Scenario 4 includes the density from the MPFM, to investigate the impact of the mixture density Scenario 5 includes both density and water cut measurement from the MPM. Lastly, scenario 6 does not include the downhole sensors but uses a downhole pressure value estimated using the IPR model. The goal is to evaluate if the IPR estimation can replace the downhole measurements without losing much accuracy. This scenario is useful for mature fields where downhole sensors are not widely installed.

Results

The 6 scenarios were run in the VFM and the calculated flow rates were compared with the MPFM flow rates. To compare the results the absolute percentual error (E_p) is described in Eq 2.

$$E_p = \frac{|Q_c - Q_M| * 100}{Q_M} \tag{2}$$

The results are presented in Table 4. The calibration procedure proved to be the greatest contribution to reduce the error. The incorporation of the water cut in scenario 3 also enhanced the VFM prediction. On the other hand, the mixture density incorporation from Scenario 2 to Scenario 4 did not reduce the errors for all wellbores, only for W3. In scenario 5, the combination of the water cut and the density is similar to Scenario 3. Lastly, the replacement of the downhole sensor for an IPR model increased the errors significantly. However, by the nature of the IPR model, this approach can provide a good estimation, if the IPR is representative.

Table 4- Scenario results

Absolute percentual error (%)			
	W1	W2	W3
Scenario 1	18.8	22.7	23.8
Scenario 2	12.3	13.7	12.8
Scenario 3	9.8	10.2	12.3
Scenario 4	12.4	13.7	12.0
Scenario 5	9.8	10.2	12.3
Scenario 6	25.2	25.1	29.0

Conclusions

This work presented a VFM as a digital technology able to transform data into valuable information to support our industry's digital transformation. The effects of available instrumentation were investigated to provide a better understanding of the technology, as well as the use of calibration and the substitution of downhole pressure for an IPR model. This evaluation is important for scenarios with the absence of a downhole gauge and to justify its investment.

The technology provides reliable measurements. Incorporating the calibration procedure was proved to impact the results positively, followed by the incorporation of the water cut measurements. On the other hand, the replacement of the downhole pressure by estimation of an IPR model showed to reduce the methodology's accuracy. The flow rates and tool features provide an accessible and easy way to monitor production and help engineers in the decision-making process. The sensitivity analysis will help to map priorities and provide a deeper understanding of VFM systems.

References

[1] Bikmukhametov, T., Jäschke, J., 2020. First Principles and Machine Learning Virtual Flow Metering: A Literature Review. J. Pet. Sci. Eng. 184, 106487. https://doi.org/10.1016/j.petrol.2019.106487

[2] Amin, A. (2015). Evaluation of Commercially Available Virtual Flow Meters (VFMs). Offshore Technology Conference, May, 1–26. https://doi.org/10.4043/25764-ms

[3] Varyan, R. (2016). Cost saving of implementing virtual flow metering at various fields and engineering phases - A case study. Offshore Technology Conference Asia 2016, OTCA 2016, 893–900.

[4] Mokhtari, K., & Waltrich, P. J. (2016). Performance evaluation of multiphase flow models applied to virtual flow metering. Advances in Fluid Mechanics XI, 1(Afm), 99–111. https://doi.org/10.2495/afm160091

[5] Alimonti, C., & Falcone, G. (2004). Integration of multiphase flowmetering, neural networks, and fuzzy logic in field performance monitoring. SPE Production and Facilities, 19(1), 25–32. https://doi.org/10.2118/87629-PA

[6] Faluomi, V., Dellarole, E., Bonuccelli, M., & Antico, L. (2006). Virtual metering system for oil and gas fields monitoring: Design, implementation and applications. 5th North American Conference on Multiphase Technology, 2006, 91–108.

[7] Xiang, M., Borden, Z., Porto, P., Burch, D., Huang, N., Benkendorfer, P., Bouquet, L., Xu, P., Swanberg, C., Hoefer, L., Barber, D. F., & Ryan, T. C. (2016). Real-Time production surveillance and optimization at a mature subsea asset. Society of Petroleum Engineers - SPE Intelligent Energy International Conference and Exhibition. https://doi.org/10.2118/181103-ms

[8] Petukhov, A. Y., Saputelli, L. A., Hermann, J. B., Traxler, A. I., Boles, K. B., Nnaji, O., Vrielynck, B., & Venugopal, D. (2011). Virtual Metering System Application in the Ceiba Field, Offshore Equatorial Guinea. SPE Digital Energy Conference, 1–21. https://doi.org/10.2118/144197-ms

[9] Poulisse, H., van Overschee, P., Briers, J., Moncur, C., & Goh, K. C. (2006). Continuous well production flow monitoring and surveillance. 2006 SPE Intelligent Energy Conference and Exhibition, 2, 514–519. https://doi.org/10.2523/99963-ms

[10] Cornwall, R. C., al Nuimi Nuimi, S. M., Tripathi, D. T., Hidalgo, M. H., Soni, S. S., & Isambertt, J. I. (2020). Using data analytics and manage by exception methodology to analyze, confirm and predict well behavior using integrated modeling approach. International Petroleum Technology Conference 2020, IPTC 2020.

[11] B. Wallis, G. (1969). One-dimensional Two-phase Flow.

[12] Varyan, R., Haug, R. K., & Fonnes, D. G. (2015). Investigation on the Suitability of Virtual Flow Metering System as an Alternative to the Conventional Physical Flow Meter. SPE/IATMI Asia Pacific Oil & Gas Conference and Exhibition. https://doi.org/10.2118/176432-MS