Mitigating Allocation and Hydrocarbon Accounting Uncertainty Using More Frequent Flow Test Data

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Abstract
Although the application of multiphase flow meters has recently increased, the production of individual wells in many fields is still monitored by occasional flow tests using test separators. In the absence of flow measurement data during the time interval between two consecutive flow tests, the flow rates of wells are typically estimated using allocation techniques. As the flow rates, however, do not remain the same over the time between the tests, there is typically a large uncertainty associated with the allocated values. In this research, the effect of the frequency of flow tests on the estimated total production of wells, allocation, and hydrocarbon accounting has been investigated. Allocation calculations have been undertaken for three different cases using actual and simulated production data based on one to four flow tests per month. Allocation errors for each case have subsequently been obtained. The results show that for all the investigated cases, the average allocation error decreased when the number of flow tests per month increased. The sharpest error reduction has been observed when the frequency of the tests increased from one to two times per month. It reduced the allocation error for the three investigated cases by 0.43%, 0.45%, and 1.11% which are equivalent to $18.2M (Million), $18.9M, and $46.8M reduction in the yearly cost of the allocation error for the respective cases. The reductions in the allocation error cost for the three cases were $27M, $29M, and $80M, respectively, when the flow tests have been undertaken weekly instead of monthly.

Keywords: Allocation, Hydrocarbon Accounting, Surveillance, Flow Test, Well Test, Uncertainty, Flow Measurement, Reservoir Management

Introduction

In many oil and gas fields, multi-phase production from different wells is commingled and then the total flow is transferred to a separation unit, where the individual phase flow rates are subsequently measured (Figure 1). The fiscal meters that measure these flow rates provide continuous data of the total field production which is used for hydrocarbon accounting purposes. However, in such fields, there is no continuous data available for individual well flow rates since their production is not metered separately. The only data of individual wells which is available in these cases is the result of occasional flow tests (sometimes referred to as ‘well tests’ or ‘daily tests’). During a flow test, the production of a single well is guided into a test separator for a short time (typically a few hours) before it is mixed with the total production. The phase flow rates of the well are subsequently measured over the test time by single phase flow meters at the individual outputs of the test separator. The test is normally repeated after a certain time interval for all wells in a field. The production data for individual wells is consequently intermittent and there is typically a gap of a several weeks to a few months between the next set of data points depending on the decision of the operators. Although the installation of mlti phase flow mters (MPFM) for individual wells has become more popular recently [1-3], there are still many fields producing under the same circumstances as outlined. In such fields, the production data of an individual well is estimated by employing the results of the intermittent flow tests and the continuous measurements of the fiscal meters in a process which is called allocation or back allocation [4]. The term ’allocation’ is also used in other exercises in the oil and gas industry, such as gas lifting [5-8] or water injection [9]. In this work, however, the term refers to the exercise defined above.

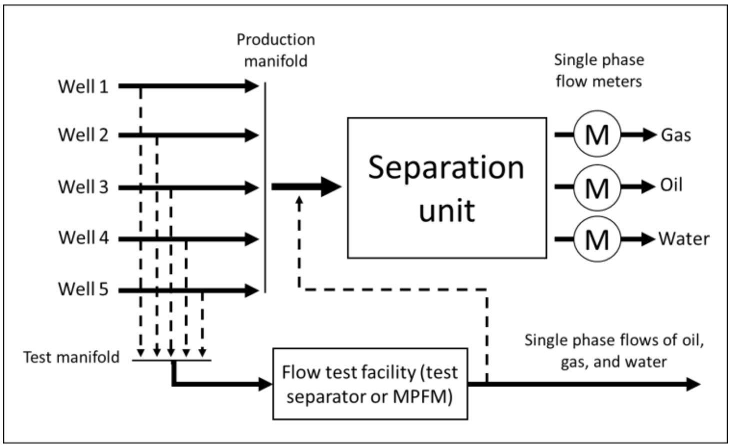


Figure 1: Schematic of the flow measurement facilities in an oil and gas field. While the total production of the field is normally measured continuously by single phase flow meters, the flow rates of individual wells, in many cases, are measured occasionally by the flow test facility whichincludes a test separator or a Multi-Phase Flow Meter (MPFM).

Different methods have been presented in the literature or employed in the industry for performing allocation calculations [10-15]. The purpose of all of these methods is to estimate the production of a single well using the available data. A common approach which is widely used in the industry is to calculate allocation factors once flow tests are undertaken. The allocation factor of a well is the proportion of the total (commingled) flow that the well is producing. These factors are used to estimate the production of each well during the time between two tests and then are updated when the new test results are available. Therefore, in this approach, it is assumed that the allocation factors remain the same as the test time over the entire time taken to the next test. Since the duration of the test is just a few hours (e.g. six hours), and in many cases the flow tests are undertaken monthly, the allocation factors which have been calculated based on the data taken in less than 1% of time are assumed to be constant for the remaining 99% of the production period [10]. Production rate fluctuations, the natural decline of production, water or gas breakthrough, and many other similar phenomena in the reservoir, well, or production facilities, however, can change the allocation factors over time. Therefore, using constant allocation factors for a relatively long period of time such as a month seems to cause a large uncertainty in the estimated production data of individual wells. A number of researchers have therefore tried to find solutions for mitigating the allocation uncertainty. Cramer, Schotanus, Ibrahim and Colbeck [10] suggested performing daily allocations using the estimations of virtual flow meters instead of discontinuous allocations based on flow tests. Although the performance of virtual flow meters has improved over time, their accuracy under all condition ranges is still not the same as actual flow metering facilities. Kaiser [16] presented two different allocation methods using decline curve analysis and mixing ratios. Neither of the methods need flow test data. A thorough comparison of their accuracy with the accuracy of the traditional allocation method, however, has not been presented. Pobitzer, Skålvik and Bjørk [13] proposed an algorithm that helps choosing the right meter and its place in the allocation process. Therefore, their focus was on optimising the allocation system setup for reducing the allocation uncertainty. Shoeibi Omrani, Dobrovolschi, Belfroid, Kronberger and Munoz [17] employed a machine learning technique to improve the accuracy of back allocation and virtual flow metering. They used pressure, temperature, choke opening, and the number of wells in the fields as the inputs to their artificial neural network. Although the machine learning method looks promising in reducing the error, its inputs must be chosen carefully. Pressure and temperature are related to the flow rate but they might not be the best inputs to represent the fluctuations in the production. In the present article, we have employed statistical parameters to quantify the characteristics of flow rate fluctuations. The resulting values can therefore be used as inputs to machine learning techniques.

Coinciding with recent developments in multi-phase flow monitoring technologies [18-21], some researchers such as Theuveny and Mehdizadeh [3] or Falcone, Hewitt and Alimonti [1] suggested that the application of MPFMs can reduce the uncertainty in production data. Although the improvements in the accuracy of MPFMs makes them one of the main potential alternatives to the traditional allocation method, the high cost of their application still remains a challenge in replacing test separators with them. It requires a considerable capital cost to install MPFMs on each individual well and also an operating cost for their regular maintenance and calibration. Moreover, the wells need to be shut during the installation process if the MPFMs are intrusive. Shutting the wells can cost the operators up to millions of dollars each day. All of these factors show the importance of a careful consideration of the cost of the uncertainties of the traditional allocation method and comparing it against the cost of using MPFMs. One aim of this article is to present an approach to estimate the potential cost of uncertainties of the traditional allocation method based on some simple statistical analyses of the test data.

Estimated production data is used for different purposes in the oil and gas industry. Therefore, not only can the uncertainty affect the allocation and hydrocarbon accounting calculations and the income of all involving parties, but also the process of reservoir management and the actual performance of the reservoir. Sadri, Shariatipour, Hunt and Ahmadinia [22] showed how the uncertainty in the flow measurement data of individual wells can affect a history matching practice and cause uncertainty in reservoir models. The reservoir model is used in the decision making process for the actual reservoir. Therefore, the production data uncertainty can potentially influence the performance of the reservoir and reduce its economic recovery indirectly. Marshall, Sadri, Hamdi, Shariatipour, Lee, Thomas and Shaw-Stewart [23] investigated the effect of flow measurement uncertainty on the estimated recovery factor of reservoirs. They concluded that the uncertainty in flow measurement data can lead to incorrect estimated values for the recovery factor. Cramer [24] focussed on the cumulative effect of the uncertainties over the whole time of production and concluded that the commercial penalty of uncertainties over a long time can be considerable. These publications suggest that allocation accuracy plays an important role in reservoir management which cannot be ignored. There is a plethora of publicatons re that show the applications of production data in different parts of reservoir management and exploitation [25-29]. The uncertainty in the production data can also affect all of these practices.

Despite the indirect and subtle effect of flow measurement and allocation uncertainty on oil and gas recovery and reservoir management, its effect on hydrocarbon accounting is direct and clear, especially where there are several owners whose wells contribute to the total commingled production. In such a case, for every single barrel of oil which is allocated incorrectly, the equivalent amount of income goes to a wrong party. The allocation calculations should therefore be undertaken as carefully as possible since the cumulative effect of any small error over time can cost the owners a huge amount of income. When considering the importance of the allocation process in hydrocarbon accounting, oil and gas companies normally have specific standards and guidelines for how to undertake it. These standards should also be in line with government regulations. The UK Energy Institute [12] has published some guidelines for the allocation of oil and gas streams which mainly presents different methods of allocation calculations. This document has been suggested as a reference by the British Oil and Gas Authority [30]. The American Petroleum Institute [31] has explained operating guidelines for allocation measurement systems in the oil and gas industry including suggestions on how to perform metering, calibration, calculations, and proving. These guidelines and recommendations can help operators to mitigate the uncertainty in obtaining production data and undertaking hydrocarbon accounting calculations. Despite the existence of these guidelines, however, there still remain considerable uncertainties in the allocation processes in some cases. One significant source of uncertainty is the lack of continuously measured production data of individual wells between two consecutive flow tests, as discussed above.

In this paper, the effect of increasing the frequency of flow tests for individual wells on reducing the uncertainty of the allocation calculations has been investigated. In the following section, the methodology and the details of the calculations have been explained.

The actual production data of three oil wells has then been analysed statistically and the fluctuations in the production data have been quantified using its relative standard deviation (RSD). The estimated total production (ETP) of the wells based on monthly flow test results has then been compared with their actual total production and the errors have been reported. The same procedure has been used for undertaking two, three, and four flow tests per month and the change in the ETP error has been observed. In the next step, the relative standard deviations of the wells have been used to apply the same fluctuations to the production data of 36 wells in a simulated reservoir. Using the resulting data sets, allocation and hydrocarbon accounting calculations for one, two, three and four flow tests per month have been performed by employing the Matlab Software [32]. The errors and their total cost for each case have subsequently been reported and compared. The allocation and hydrocarbon accounting calculations have been repeated several thousand times (100 times for each case) with different patterns of fluctuations to secure the reproducibility of the results. Finally, the conclusions of the research undertaken have been presented.

Methodology

The actual production data of three oil wells, measured by MPFMs, has been employed in this research (Well A, B, and C in Figure 4 and Table 1). In the first part of the research study, the data has been used to calculate and compare the Actual Total Production (ATP) of the wells based on the MPFM data and their Estimated Total Production (ETP) based on occasional flow tests (Equations 2 and 3). The error in estimations has subsequently been calculated and reported. In the first section, no allocation calculations have been undertaken since the data of a whole field is needed for such calculations. For each well, the total time of the investigation has been assumed to be the time that its production data is available and the estimated cumulative production of each well over the whole investigation time has been referred to as the Estimated Total Production (ETP) of the well.

In the oil and gas industry, the cumulative production for each time interval is considered to be equivalent to the production flow rate multiplied by the length of the production time interval (Equation 1). When there are multiple time intervals, the cumulative production for the total time (i.e. ETP) is calculated based on Equation 2. Production flow rate, however, is not constant over time. Therefore, assuming a constant production flow rate over a long time interval (e.g. a month) causes uncertainties in the estimated total production. The assumption is more acceptable when the time interval is shorter. In other words, choosing shorter time intervals means a more accurate ETP. ETP is theoretically in its most accurate condition when the time intervals approach zero, as shown in Equation 3. Under such a condition, ETP has the same value as the Actual Total Production (ATP) which is equivalent to the area under the production flow rate plot when it is sketched as a function of time (Figure 2).

$$CP_{\Delta t_{i+1}} \approx Q_{t_i}(t_{i+1} - t_i) \qquad \textit{Equation 1}$$

$$ETP_{t_n} = \sum_{i=0}^{n-1} Q_{t_i}(t_{i+1} - t_i) = \sum_{i=0}^{n-1} Q_{t_i}\Delta t_i \approx ATP_{t_n} \qquad \textit{Equation 2}$$

$$ATP_{t_n} = \lim_{\Delta t_i \to 0} \sum_{i=0}^{n-1} Q_{t_i}\Delta t_i = \int_{t_0}^{t_n} Q dt \qquad \textit{Equation 3}$$

In Equations 1 to 3, t is time, t_n is the total time of the investigation, $CP_{\Delta t_{i+1}}$ is the cumulative production over the $(i+1)th$ time interval, Q_{t_i} is the production flow rate at the time t_i, ETP is the estimated total production, and ATP is the actual total production. The values of all the parameters in Equations 1 to 3 must be calculated under standard conditions in the oil and gas industry (i.e. pressure and temperature equal to 101 KPa and 288.7K, respectively) to avoid any effect of pressure or temperature change on the results of equations.

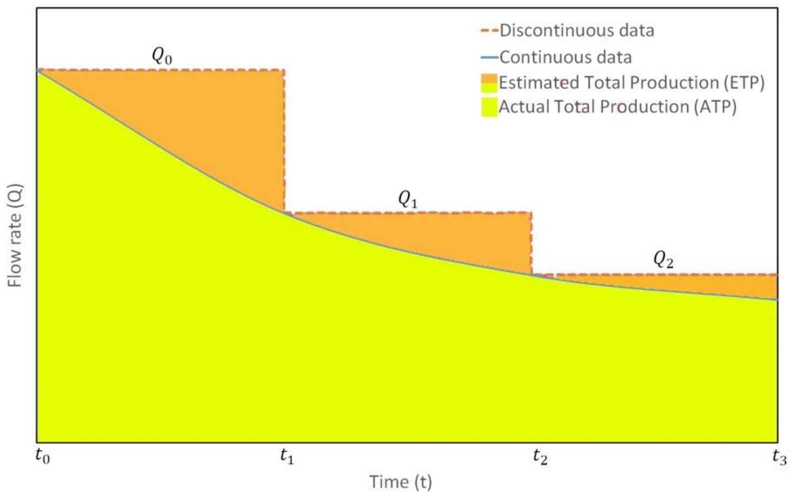


Figure 2: Estimated Total Production (ETP) and Actual Total Production (ATP); The orange area shows their difference. Shorter time intervals reduce the orange area, hence the error in estimations. ETP and ATP are theoretically equal if the time intervals approach zero (i.e. for continuous flow measurement).

In practice, the time between two flow tests is the time interval in Equation 2. It is the shortest time interval in which the production data for individual wells is available. Therefore, the most accurate ETP is obtained when production data for individual wells is recorded continuously, since in that case the time between two consecutive measurements approaches zero (Equation 3). Although it is not always possible to obtain continuous data (e.g. installing MPFMs for each well) in practice, shortening the time interval between flow tests may be effective in decreasing ETP errors. In this research, first, the ETPs of the three aforementioned wells (Well A, B, and C) have been calculated using Equation 2 for a case when one flow test per month is undertaken, that is common practice in the oil and gas industry. The results have then been compared to the respective ATPs based on the available MPFM data to determine the error in the ETPs based on Equation 4:

$$E_{ETP} = \frac{ETP - ATP}{ATP} \times 100 \qquad \text{Equation 4}$$

where E_{ETP} denotes the estimated total production error, *ETP* stands for the estimated total production (based on flow test data), and *ATP* is the actual total production (based on MPFM data).

In the next step, for the wells having an ETP error of over 2%, the number of flow tests per month has been increased to two, three, and four and the observed trend of decreasing the error for each well has subsequently been presented.

The ETP of individual wells is not just calculated based on the flow test measurements. In the oil and gas industry, flow test results are modified in the allocation process. Therefore, to have realistic research results, in the second part of this research project the production results of a simulated oil field with 36 production wells were studied to investigate the effect of increasing the number of flow tests per month on allocation error and hydrocarbon accounting. The same fluctuations as the ones in the data sets of the three actual wells (Wells A, B, and C) were applied to the production results of the Schlumberger Eclipse Simulator [33] by employing Equation 8 and using the Relative Standard Deviation (RSD) of the real data. Therefore, three respective cases (Case A, B, and C) were created and subsequently used in the study. A relative standard deviation (RSD) (Equation 6) was used instead of a standard deviation to quantify the dispersion of the data points because despite standard deviation RSD is independent of the average production rate. In addition, the RSDs were calculated based on monthly time intervals to reduce the effect of production decline on their value. As a result, for Well B and C the reported RSDs in this work are their average monthly values. It should be mentioned that the effect of production decline over time on the value of RSDs cannot be completely eliminated since the exact trend of production decline cannot be detected in short periods of time. when the production period is short, such as a month, however, the production decline is normally small and negligible compared to the production fluctuations. Therefore, choosing short time intervals as the basis of the calculations can minimise this potential error. Combining the simulator outputs and the random numbers generated by a Matlab [32] code based on Equation 8 resulted in the reference production data for the allocation and hydrocarbon accounting calculations.

$$SD = \sqrt{\frac{\sum_{i=1}^{n}(x_i - \overline{x})^2}{n}} \qquad \text{Equation 5}$$

$$RSD = \frac{SD}{\overline{x}} \qquad \text{Equation 6}$$

$$\mathbf{DF} = \frac{RSD}{SD_{\mathbf{RND}}}\left(\mathbf{RND} - \frac{1}{2}\right) \qquad \text{Equation 7}$$

$$\mathbf{D_{ref}} = \mathbf{D_{sim}}.(1 + \mathbf{DF}) \qquad \text{Equation 8}$$

In Equations 5 to 8, n is the number of data points, x_i represents the *i-th* data point, $\overline{x}$ is the average of all data points, **RND** denotes the vector of random numbers evenly distributed between zero and one, $SD_{\mathbf{RND}}$ represents the standard deviation of the vector of random numbers, *RSD* is the relative standard deviation of the actual production data, **DF** stands for the vector of dispersion factors, $\mathbf{D_{sim}}$ is the vector of the production data from the simulator, and $\mathbf{D_{ref}}$ denotes the vector of reference production data which has been used in the allocation analysis.

The allocation and hydrocarbon accounting calculations were subsequently undertaken using the Matlab code. The gap between two consecutive flow tests were considered to be a month and the length of each test was assumed to be six hours. The test flow rate for each well was considered to be the arithmetic mean of the available data points during the test time (Equation 9). Allocation factors have been calculated using the test results and the accurate total flow rate of the whole field (which is equivalent to the measurements of the fiscal meters in an actual field) based on Equation 10. Allocation factors which were calculated based on a flow test remained the same until the next flow test when they were updated with new values. ETP and ETP error for each well have been calculated according to Equation 11 and 12, respectively.

$$\overline{Q} = \frac{\sum_{i=1}^{n} Q_i}{n} \qquad \textit{Equation 9}$$

$$AF_k = \frac{\overline{Q}_k}{\sum_{i=1}^{m} \overline{Q}_i} \qquad \textit{Equation 10}$$

$$ETP_k = AF_k . TP_{field} \qquad \textit{Equation 11}$$

$$AE\% = 100 \frac{\sum_{k=1}^{m} \left| ETP_k^{test} - ETP_k^{ref} \right|}{2 \sum_{k=1}^{m} ETP_k^{ref}} \qquad \textit{Equation 12}$$

In Equation 9 to 12, $\overline{Q}$ is the average flow rate of the well during the test time, Q_i represents the *i-th* measured flow rate data point during the test, *n* denotes the total number of the available measurements of the test, AF_k stands for allocation factor for well *k*, *m* is the total number of contributing wells, ETP_k denotes the estimated total production of well *k*, TP_{field} is total production of the whole field (i.e. total production of all contributing sources which is measured by fiscal meters), *AE%* shows the allocation error, and *test* and *ref* superscripts denote the test results and reference data, respectively.

Figure 3 illustrates the flow chart of the entire process of calculations undertaken by the Matlab code and the reservoir simulator.

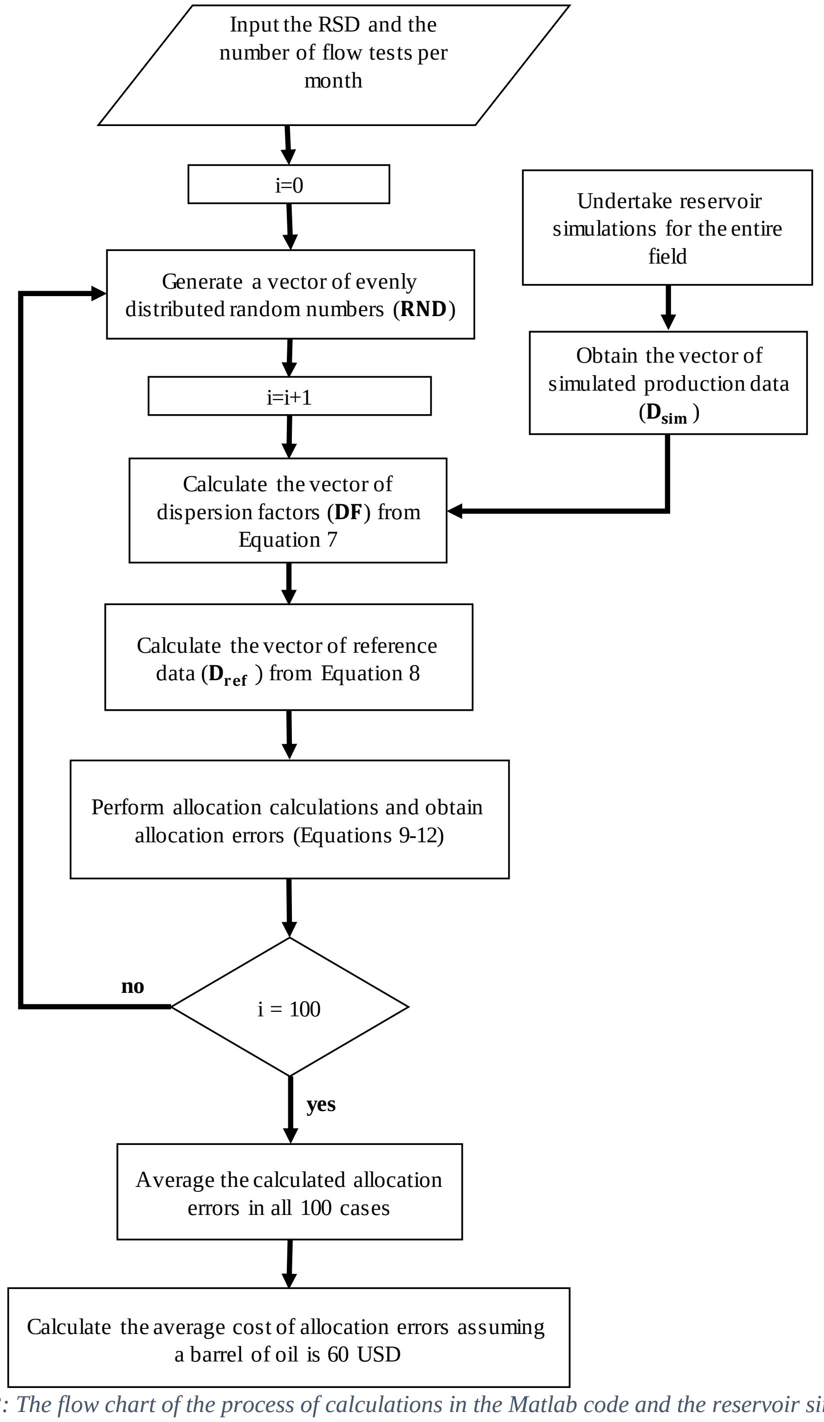


Figure 3: The flow chart of the process of calculations in the Matlab code and the reservoir simulator.

The aim of the allocation process is to determine the contribution of each well to the total field production. Therefore, the allocation error in this article is defined as the fraction of the total field production which has been allocated to wrong wells (Equation 12). Each barrel of oil which is allocated incorrectly affects the ETP of two wells: the well that truly produces it and the well that incorrectly receives it. Therefore, each single percentage of allocation error causes a two percentage average error in the ETP of the individual wells.

The resulting errors after undertaking the calculations can properly show the uncertainty in the allocation process for the reference production data.,There is no guarantee, however, that the same results are obtained for the same field and the same RSDs if the calculations are repeated with a different pattern of production flow rate fluctuations. Although an RSD shows how scattered the data is, it does not give any information about the value of the individual data points. Therefore, the reference production data can take different patterns under the same RSD which can result in different calculated allocation errors. To resolve this problem, the allocation calculations for the same RSDs were repeated 100 times and the range and arithmetic mean of the errors was obtained and reported. For each new calculation, the Matlab code generated a new set of random numbers but with the same RSD to make a new pattern in the well flow rate fluctuations. This strategy properly guarantees the reproducibility of the results.

After undertaking the allocation calculations for one flow test per month, all the calculations were repeated for two, three, and four tests per month, respectively. The average allocation errors have been calculated and compared for all the cases. The results show how the frequency of the flow tests can affect the error in allocation calculations. For some cases, the equivalent total cost of allocation errors has also been reported (each standard barrel of oil has been considered to have a value of 60$). Finally, the change of the ETP errors of individual wells for Case C, which has had the greatest RSD, has been analysed when the number of flow tests per month has been increased from one to four. The results have been presented in the next section.

Results and discussion

As mentioned in the previous section, the measured flow rate data of three actual wells has been analysed in this work. The extent of the fluctuations (i.e. relative standard deviations) in these three data sets is significantly different. The ranges of fluctuations in the real data have been used to generate the ranges of fluctuations in the synthetic simulated data in this study. Figure 4 shows the flow data of the three actual wells [34-36] and Table 1 presents the values of some of their statistical parameters. The data have been measured by Multiphase Flow Meters (MPFM) and the gap between the available data points varies between 20 minutes to 18 hours.

Table 1: Statistics of the well data

Well Name	Time (days)	Standard deviation (Equation 2)	Relative standard deviation* (Equation 3)	Arithmetic mean (STB/day)
Well A	20	105.72	0.007444695	14200.86
Well B	60	1169.55	0.060131618	17229.19
Well C	150	25104.19	0.31186466	8336.77

* The reported values for Wells B and C are the average monthly relative standard deviation. The value for Well A is based on its available production data in 20 days.

The time interval between undertaking two flow tests with the test separator is different in different fields. Companies decide about the regularity of the tests based on different operational factors involved in the hydrocarbon production of the fields under their control. Therefore, different operators may choose to do the tests in different time intervals. It is common, however, for many companies in the oil and gas industry to test individual well flow rates at monthly intervals. One reason for this is that many companies undertake calculations related to hydrocarbon production (hydrocarbon accounting, allocation, tax payment) and prepare reports (for internal use, government authorities or publication on their websites) on a monthly basis. To investigate how accurate the results of intermittent flow tests can represent the average production of each well during the gap between two tests, the flow measurement data of the three oil wells shown in Table 1 was studied.

Figure 4 shows the oil production plots against time for Wells A, B, and C. The solid lines show the well production based on the measurements of MPFMs and the dashed lines illustrate the values of monthly flow tests. The values for the flow tests is the average of the available MPFM data points for a duration of 6 hours.

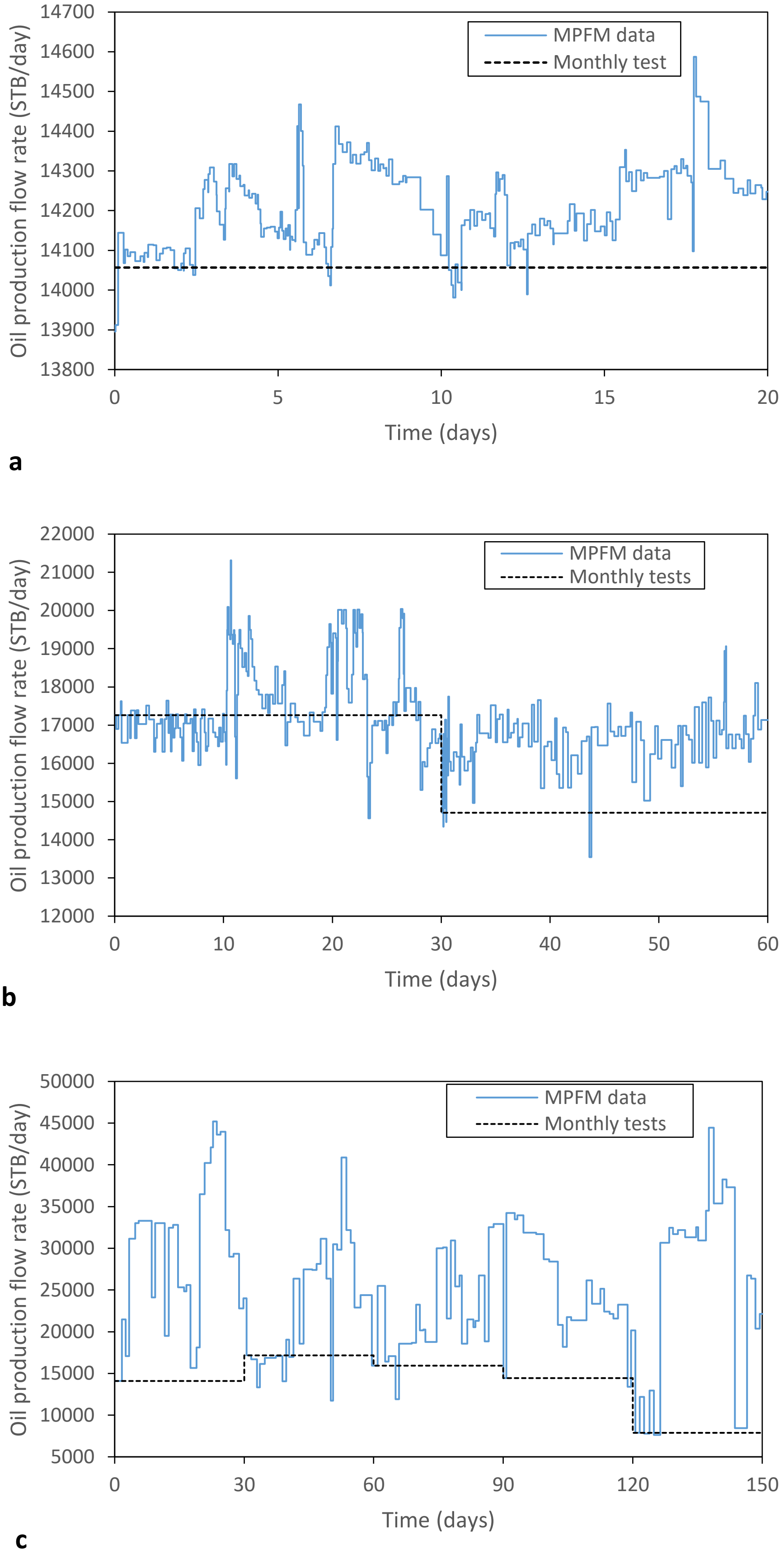


Figure 4: Comparison between MPFM and Flow test data for Well A (a), Well B (b), and Well C (c)

Figure 4 clearly shows the difference between the measurements of the MPFMs and the flow tests. The total production for each well based on the MPFM and flow test data has been calculated and compared. The results have been shown in Table 2.

Table 2: Production estimations for Wells A, B, and C

Well name	Period of production (days)	Estimated total production (ETP)				
		based on MPFM data (STB)	based on monthly flow test data (STB)	Difference (STB)	Difference ($)	ETP error (Equation 4)
Well A	20	284205	281135	3070	184200	-1.08
Well B	60	1022175	958974	63201	3792060	-6.18
Well C	150	3799238	2085391	1713847	102830820	-45.11

The RSD of Well C is the largest in Table 1, suggesting that the measured data is scattered over a larger range compared to the other two wells. Values in Table 1 and 2 show that a greater RSD has caused an increase in the absolute value of ETP difference in the studied cases. The MPFM data has been assumed to be the actual production data of the wells since it is the most accurate data which is available in this work. The last column of Table 2 shows the errors in estimating the total production for the wells based on the monthly flow tests. These errors are -1%, -6%, and -45% for Wells A, B, and C, respectively, which is equivalent to 0.2M (Million), 3.8M, and 102.8M dollars' worth of oil, respectively. The absolute values of the estimation errors for the RSDs of the three wells have been presented in Figure 2.

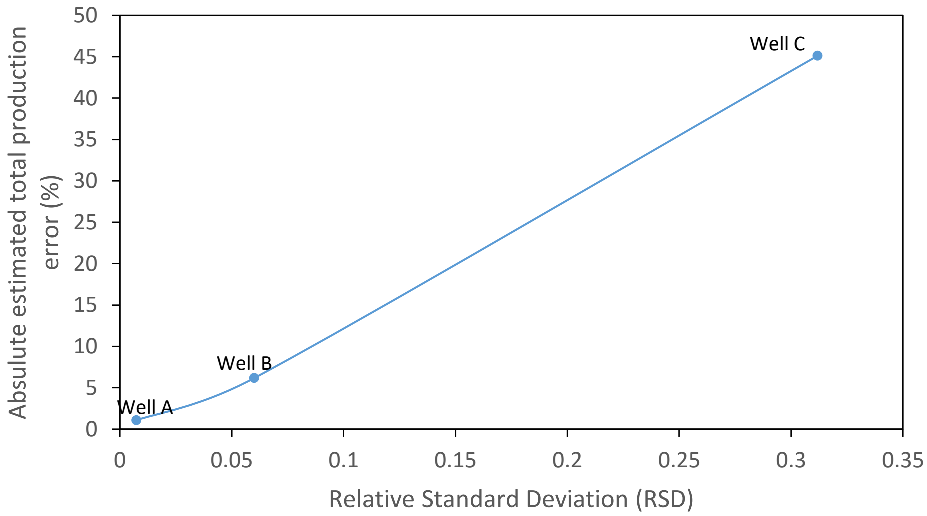


Figure 5: Absolute Estimated Total Production (ETP) error for Wells A, B, and C as a function of the Relative Standard Deviation (RSD) of their production data

The absolute ETP error has significantly increased when the relative standard deviation (RSD) has risen. The error goes higher than 10% when the RSD is greater than 0.08, as shown in Figure 5. Therefore, the results suggest that for larger RSDs in the investigated cases, estimations based on monthly flow tests include larger uncertainties. Although a general conclusion cannot be made just based on three data points, the case studies show a possibility of having large uncertainties when production fluctuations are large. It should be added, however, that in practice in the oil and gas industry, the data taken through monthly tests are combined with the measurements of the fiscal meter in allocation calculations. Therefore, employing the data from the fiscal meter which is more accurate and regular, mitigates the uncertainty in production estimations for individual wells. The effect of the uncertainty of monthly flow test data on allocation calculations has been studied in the second phase of this research. The results have been presented below.

The effect of increasing the number of tests per month on the absolute ETP error was investigated in order to see how the regularity of the flow tests (i.e. the time gap between two consecutive flow tests) can affect the uncertainty in the ETP of individual wells. The aim of this work has been to reduce the error to less than 2%. The error for Well A based on monthly flow tests is 1.08, as shown in Table 2. Therefore, the error is already within the specification. However, for Wells B and C, the errors are greater than the target value. Figure 6 shows how increasing the number of flow tests per month can decrease the ETP error.

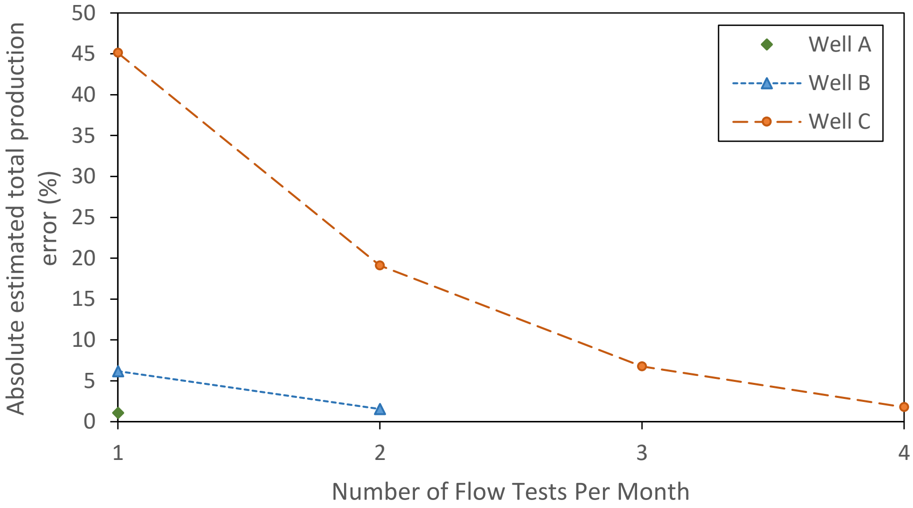
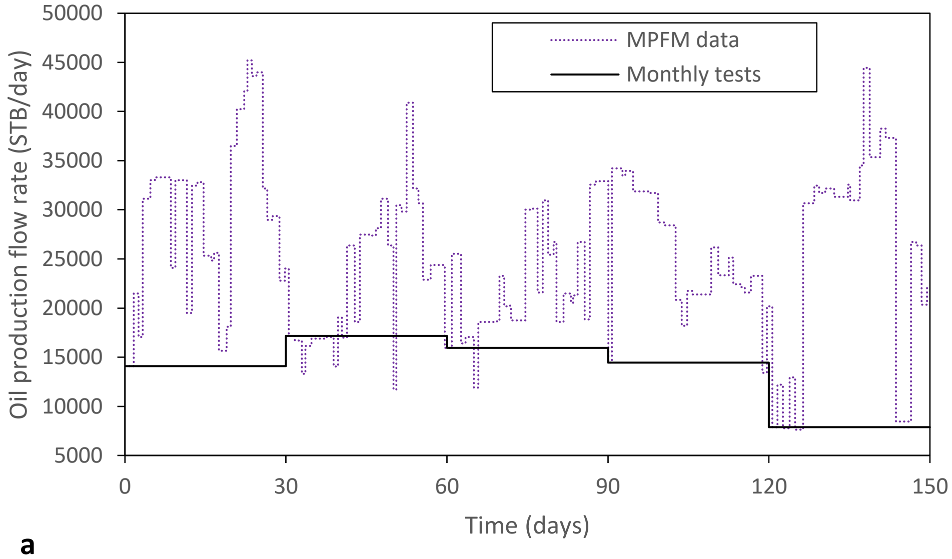


Figure 6: Effect of increasing the number of flow tests per month on the absolute estimated total production error for Wells A, B, and C

For Well B, however, undertaking two flow tests per month has decreased the error to less than 2%, while for Well C, with a larger RSD, four tests per month is required to achieve the same goal. It should be added that it is not always possible in practice to increase the number of flow tests per month to achieve the desired ETP error limit. What the results do show, however, is that where it is possible to regularly conduct tests, there is a reduction in the uncertainty in the estimations. Figure 7 shows how increasing the number of flow tests from one to four times per month can step-by-step make the estimated production plot of Well C more reflective of its production plot based on the MPFM measurements.



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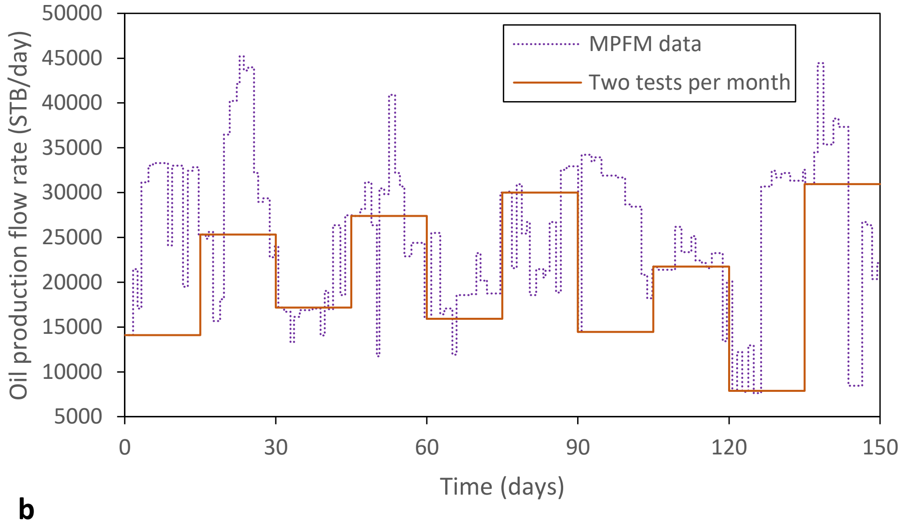

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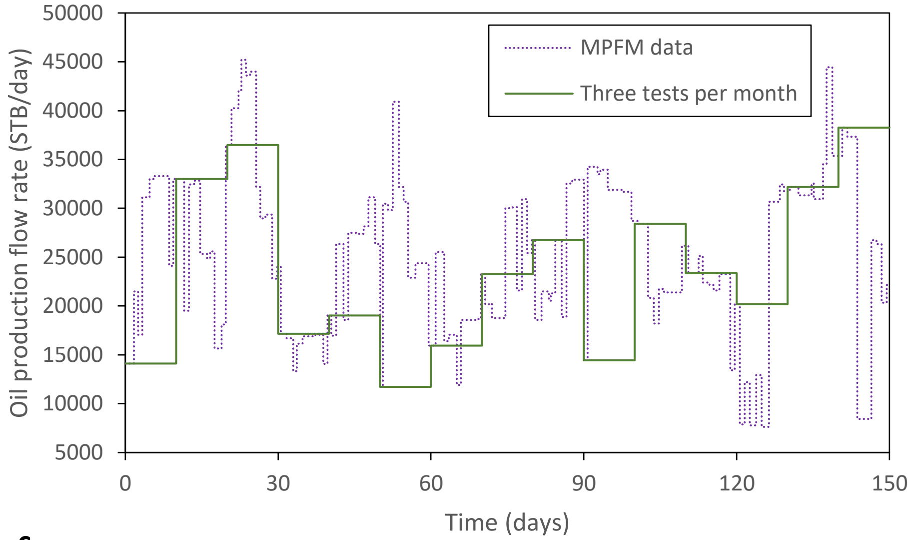

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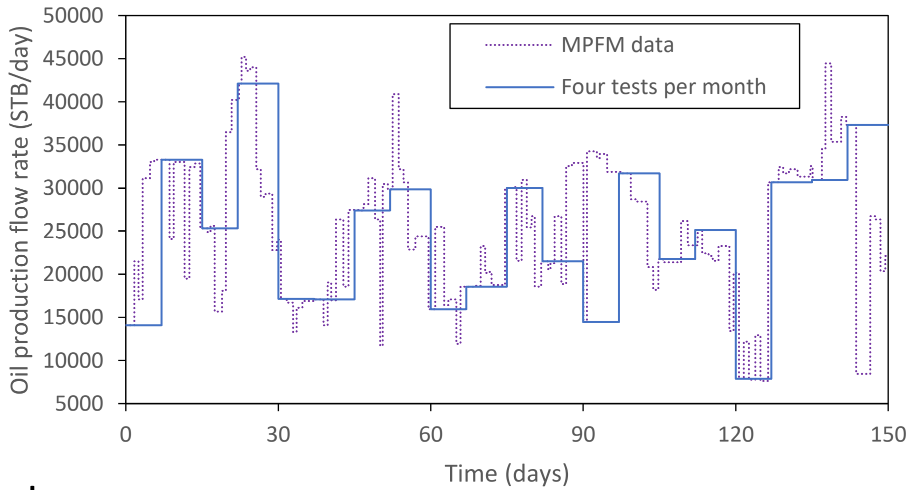

d

Figure 7: Comparison between MPFM data and flow test data when the number of flow tests per month is one (a), two (b), three (c), and four (d) for Well C. When there are more flow tests per month, the test results better match the MPFM data..

As mentioned above, in the oil and gas industry, the data from the fiscal meter which continuously measures the cumulative production of several wells is employed to reduce the uncertainty in individual well production estimations. Therefore, undertaking further studies on the data of an entire field with several wells was required to see how the non-continuous scattered data of production from individual wells can affect hydrocarbon accounting.

Allocation calculations

An oil field with 36 production wells was simulated using the Schlumberger Eclipse reservoir simulator [33] and its production results were used to investigate the effects of uncertainties in the production data of individual wells on hydrocarbon accounting calculations in a full scale oil and gas industry case. The reservoir has been assumed to be heterogeneous in order to make it more representative. Well controls and production scenarios are set so that there is a variety in the production flow rates of different wells and their trends. The reason has been to provide enough complexity to make the hydrocarbon accounting calculations of the field similar to a real case. The simulations have been run over a year based on daily time steps which has provided enough data points for the allocation calculations. In Figure 8 the output of the simulator which shows the production of all wells during the year has been illustrated.

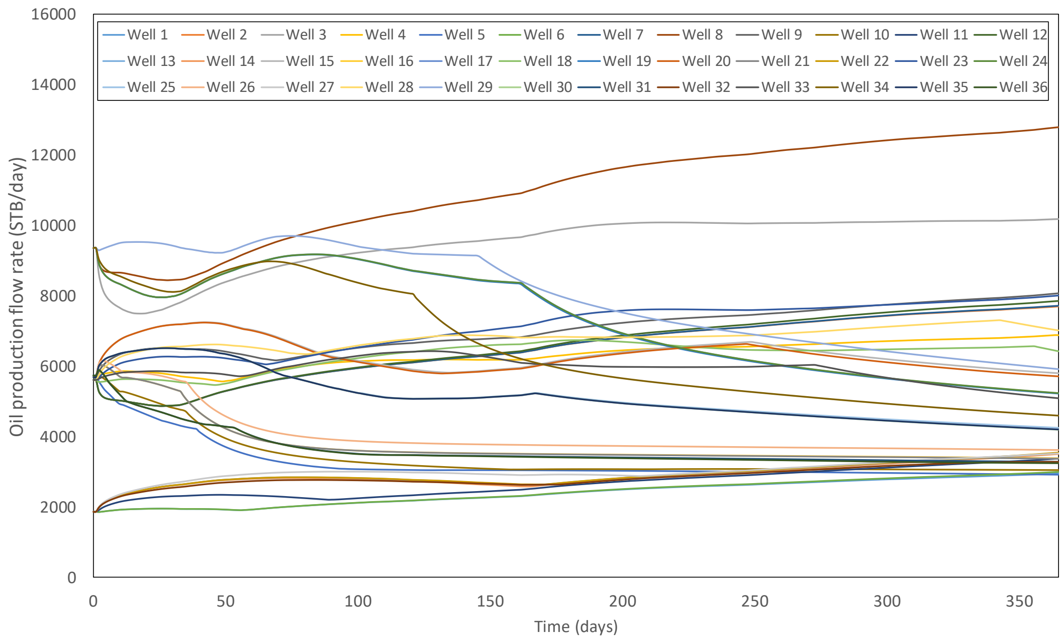

Figure 8: Oil production plots for all 36 wells in the simulated field

As shown in Figure 8, each well starts its production regime under one of the three initial flow rates (1870, 5615, or 9360 STB/day). The initial production flow rates in this scenario have been determined based on the characteristics of the drainage area of the wells. Wells which are located in more permeable areas of the reservoir start their production at a higher flow rate. Each well, however, shows a different trend of production later during the year. The characteristics of the reservoir and the wells, in addition to the constraints of production such as high water cut, have been the reasons for the later changes in the well production control. For instance, in those wells, such as Well 34 where a sudden decrease in the production has been shown, the water cut reached 80% (their perforations are in a lower depth compared to the other wells). Therefore the production flow rate for these wells has been decreased to reduce the total barrels of producing water from the field.

Regardless of how heterogeneous the reservoir model is made in the simulator, the actual reservoir is far more complex. There are always some fluctuations in the measured production data of the actual reservoir while the output of reservoir simulators are normally smooth, as shown in Figure 8. Therefore, the available production data from the actual wells which was used in the previous section (Table 1), was statistically analysed and the same fluctuations as the actual data were applied to the results of the simulator. In order to do that, the RSD (Equation 6) of each well for each month was calculated. The average of the RSD values for each well was considered the final RSD for that well. In the next step, a

Matlab [32] code generated random numbers (positive and negative) with the same RSD as the real data and applied them to the results of the simulator. Therefore, three different sets of production data (Case A, B, and C) for the whole field with the trend of the simulator outputs and the same fluctuations (i.e. RSDs) as the real data were created for the hydrocarbon accounting analysis. As an example, Figure 9 compares the output of the simulator and the final production flow rate after applying the fluctuations for Well 34. It should be noted that using real data for production in a research undertaking is ideal. It is difficult, however, to find the production data of a whole field where the production flow rate of all wells is measured by MPFMs or in daily intervals (if such data exists at all). In addition, the simulator can provide an unlimited number of data sets which is necessary for securing the repeatability of the research results. This clearly could not happen with the limited number of real data sets if they were available. As a result, in this research the limited available actual data for three individual wells were combined with the outputs of the reservoir simulator (Schlumberger Eclipse) to benefit from the advantages of performing an unlimited number of simulations and make the case similar to a real case in the oil and gas industry.

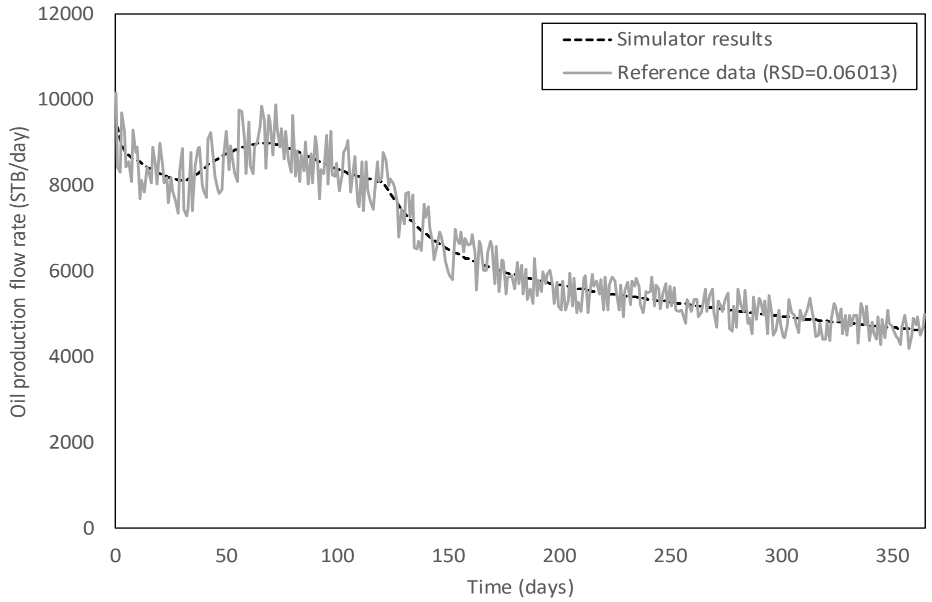

Figure 9: An example of the reference data generated by combining the simulation results for Well 34 and the real data of Well B. Simulator output plots are smooth while real production data is dispersed.

After adding the fluctuations to the production outputs of the simulator, the resulting data set was employed as the reference data set in the hydrocarbon accounting calculations. This implies that we assumed that the resulting data set was equivalent to the measured production data of the field. The same approach as the one explained in the previous section was employed to extract monthly flow test data for the individual wells. As allocation based on combining accurate measurements of the fiscal meter and the data from intermittent well flow tests is the main part of hydrocarbon accounting calculations, therefore, in the next step the flow test data and the total flow rate of the field (which is equivalent to the data of the fiscal meter) were input to a Matlab code. The code was prepared to undertake allocation calculations based on the methods and equations presented previously in the methodology section and the flow chart in Figure 3. The results of allocation calculations were subsequently used in the hydrocarbon accounting and compared with the calculation results based on the reference data to investigate the extent of errors caused by the uncertainty in the intermittent individual well flow data. Since fluctuations have different forms in different production data, it might not be accurate to generalise the research results based on one or a few study cases. Therefore, the whole process explained earlier, was repeated 100 times. Since the Matlab code generates new random numbers each time, the fluctuations in the production data are different from the previous time. As a result, for each case 100 production data sets have been analysed. In addition to the three RSDs from the actual wells, similar calculations have been undertaken for six more RSDs (0, 0.05, 0.1, 0.2, 0.3, and 0.4).The results of all the calculations have been summarised in the shape of the box and whisker plot in Figure 10.

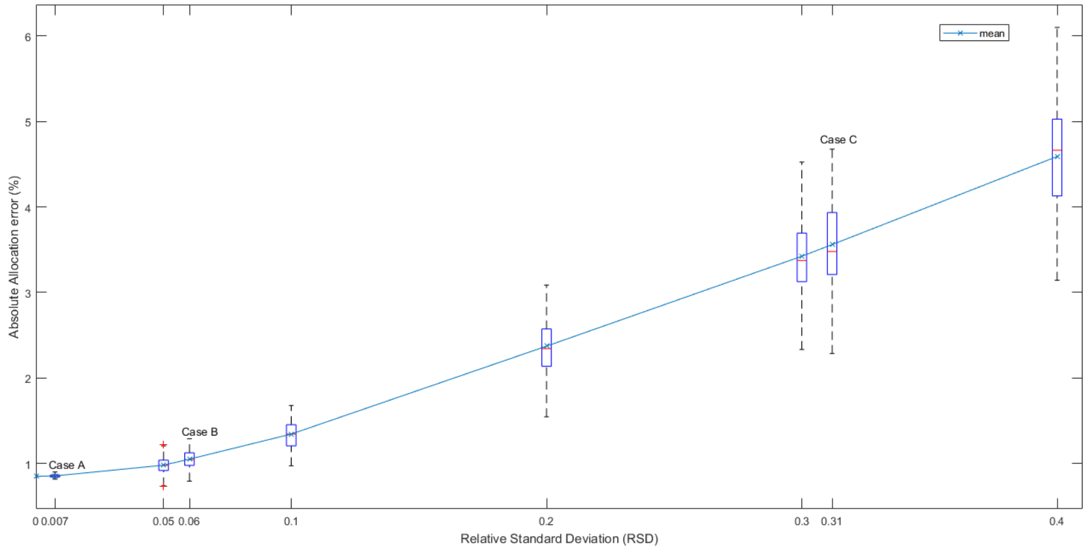

Figure 10: Box and whisker plot of absolute allocation errors as a function of relative standard deviations of Cases A, B, and C and six more arbitrary RSDs. The plot shows the range and the mean of the error as a result of 100 times calculations for each case.

Figure 10 shows the average and the distribution of errors in allocating total production to wells in 300 times calculations which have been undertaken for the three cases (100 times per case). The same calculations have been performed for six other boxes in the plot. The error has been calculated based on the method explained in the methodology section (Equation 12) and shows the percentage of the total production of the field which has been allocated to a wrong well. Both the average and the range of the error increase with a greater RSD. The average error was 0.85% for Case A (RSD=0.0074), while it has risen to 1.05% for Case B (RSD=0.0601) and 3.58% for Case C (RSD=0.3119). The range of error has also increased from Case A to Case C. The largest errors were 0.90%, 1.29%, and 4.67% for Cases A, B, and C, respectively. Figure 10 shows the error for the whole field. The error for an individual well, however, is different from the error for the whole field-being twice the error of the whole field. Note that each barrel of oil which is allocated to a wrong well is counted once for the whole field so it affects two individual wells: one well loses the barrel of oil in the estimations and the same barrel of oil is allocated to another well. Therefore, it increases the error of both wells (for one of them in the positive and the other one in the negative direction) and hence makes the average absolute error of all wells double the size of the field error. Performing allocation calculations for the individual wells also approves it. The calculated average absolute errors for the individual wells were 1.7%, 2.10, and 7.16% for Cases A, B, and C, respectively. Figure 11 shows the average absolute errors of all individual wells for each case.

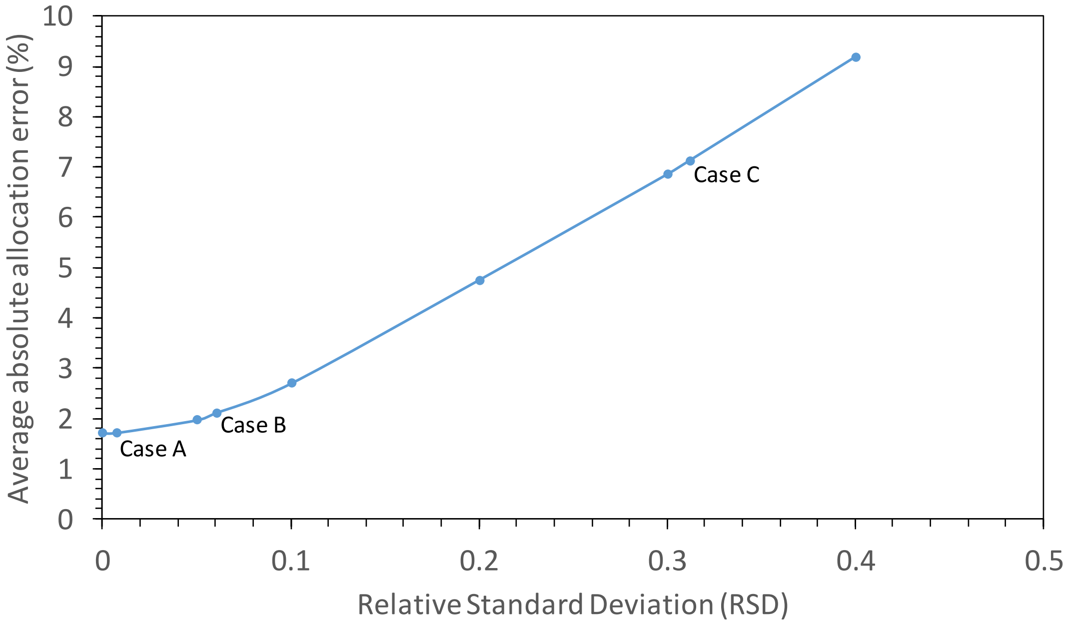

Figure 11: Absolute average allocation error for all individual wells in each case. The average absolute error for individual wells is twice as the average absolute error for the whole field.

Comparing the results in Figure 5 (flow test errors) and Figure 11 (allocation errors) shows how allocation calculations can affect the errors in the estimated production of wells. The absolute errors for actual Wells A, B and C (Figure 5) were 1.08%, 6.18%, and 45.11%, respectively. The average absolute results for Case A (1.7%) is more than the error for Well A (1.08%). The reason is that the available data of Well A is for just 20 days and its production trend has not changed significantly while the allocation error is based on one year production, including ups and downs in the well production trends. For the other two wells (B and C), the allocation errors of their respective cases (B and C) are significantly smaller than the flow test errors, although the RSDs are the same.

Although employing allocation techniques and using more accurate data of the fiscal meter, in addition to less accurate data of flow tests, can mitigate the uncertainty in the results, the errors for some cases are still unacceptable in terms of hydrocarbon accounting. The average total amount of produced oil during the year which has been allocated to a wrong well and its equivalent price (assuming the value of each barrel is 60 US dollars) has been reported in Table 3.

Table 3: Hydrocarbon accounting calculation results including the total cost of wrong allocations

Case	Period of production (days)	Average total oil production (STB)	Average total oil allocated to wrong wells (STB)	Total cost of wrong allocation (US$)	Percentage of the total production (allocation error)
Case A	365	70,396,118	598,367	35,902,013	0.85%
Case B	365	70,069,333	735,728	44,143,661	1.05%
Case C	365	69,625,196	2,492,582	149,554,906	3.58%

As shown in Table 3, allocation error shown in the last column might not look significant in some cases but its cumulative effect over a long time has a significant financial impact on the operator companies. In cases where different companies own different wells in the same field or the production from the wells of one company is commingled with the production of other companies for any reason, these costs can cause the companies to lose a large amount of income over a long time due to the allocation errors. The errors can also affect tax calculations or reservoir management [22-24, 37, 38]. Table 3 shows that the total costs for Cases A, B, and C are 35.9M (Million), 44M, and 149.5M dollars during a year of production. These numbers show the price of the total amount of produced oil which has been allocated to wrong wells. If we assume every single one of the 36 wells in this field has a separate owner, it means the reported cost is the sum of the money which has gone to wrong owners. Under such an assumption in Case C, some owners lose 149.5 million dollars of the total value of their yearly production while the rest of the owners receive the same amount of money more than the value of the oil that they have produced. Table 3 clearly shows that the allocation errors can cause owners to lose large amounts of their income over time, especially when the RSD of the production data is high (i.e. the production rate has large fluctuations and the recorded production data is highly scattered) such as in Case C. As a result, reducing allocation errors can have significant benefits for the companies in the oil and gas industry. The results that have been presented here are for the studied case. In oil and gas fields, the same analysis can be undertaken by calculating RSDs obtained from flow test results.

Previously, it was shown that by performing more frequent flow tests, the errors in the estimated total production (ETP) of individual wells can be reduced. In this section, the effect of increasing the frequency of flow tests on allocation error has been presented. In order to obtain the following results, the number of flow tests per month was increased from 1 to 2, to 3, and then to 4 and its effect on the accuracy of allocation results for all three cases was investigated. As before, all calculations have been repeated 100 times with different input random data sets and then the results have been averaged to make sure that the final results are reproducible. The allocation error as a function of the number of flow tests per month has been shown for Case A, B, and C in Figure 12.

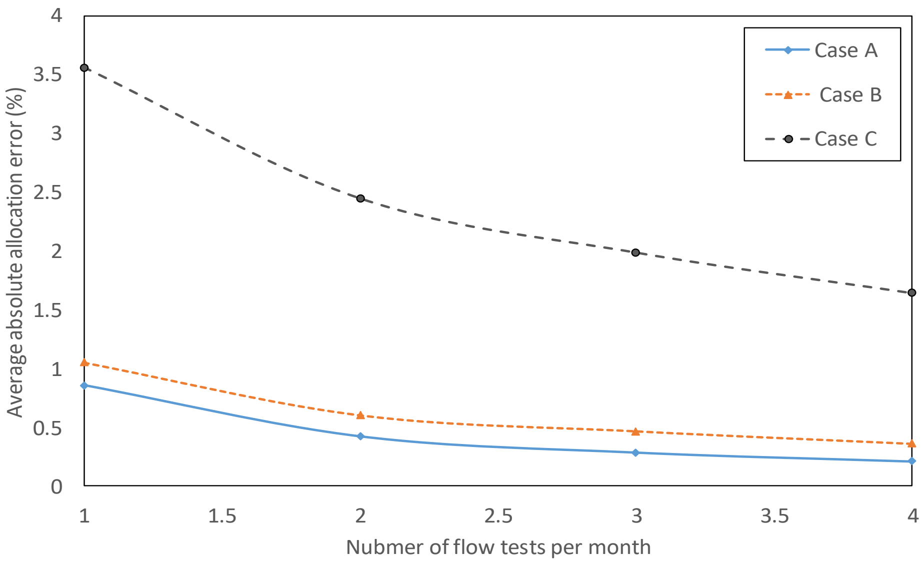

Figure 12: Average absolute allocation error as a function of the number of flow tests per month. Undertaking more flow tests per month has decreased allocation uncertainty in all cases.

Increasing the number flow tests per month decreased the allocation error in all three cases, as illustrated in Figure 12. In all cases there is a sharper decrease from one test per month to two, then it continues with a smoother slope to three and four tests per month. Increasing the number of flow tests per month from one to two decreased the allocation errors of Cases A, B, and C by 0.43%, 0.45%, and 1.11%, respectively, which are equivalent to 18.2M, 18.9M, and 46.8M US dollars reduction in the yearly cost of allocation error for the respective cases. Table 4 shows how increasing the number of the tests per month (TPM) can reduce the cost of allocation error for all cases.

Table 4: Reduction in the total yearly cost of allocation error when increasing the number of flow tests per month

Case	Reduction in the total yearly cost of allocation error when increasing the number of flow tests per month (million dollars)		
	1TPM to 2TPMs	1TPM to 3TPMs	1TPM to 4TPMs
Case A	18.2	24.0	27.1
Case B	18.9	24.5	29.0
Case C	46.5	65.7	80.1

Based on Table 4, the results show that undertaking more flow tests per month can reduce the total cost of allocation. In practice, however, there are many other factors which should be considered. Firstly, performing more frequent tests may not always be possible due to operational constraints. Secondly, more flow tests require more operational or even capital expenditure. Therefore, the constraints need to be considered and the costs and benefits be estimated and compared for each individual field. Another option is installing MPFMs for individual wells. MPFMs can provide real-time continuous production data for individual wells. Some MPFM manufacturers and experts also believe that, as there is no need for test separators when MPFMs are installed on wells, therefore they can eliminate the capital cost spent on installing the test separator and its related flow lines. Installing MPFMs, however, also requires spending on capital and operating costs. The price of MPFMs and the cost of their maintenance should also be considered. The well which is equipped with the flow meter might also need to be shut for the duration of the installation of the hardware if the MPFM is intrusive. All these aforementioned factors create extra costs which should be compared with the benefits before making any decision. Another fact that needs to be regarded is that the benefit to all owners from increasing the accuracy of the measurements is not the same. Although the average cost for the entire field is reduced, some owners might benefit more than the others. To show how more frequent tests can affect each single well, allocation calculations for Case C were performed using the same random number data set (i.e. exactly the same fluctuations in the production flow rates) for when 1, 2, 3, and 4 flow tests per month are performed. Figure 13 illustrates the allocation errors for all 36 individual wells and also the average absolute allocation errors for all wells.

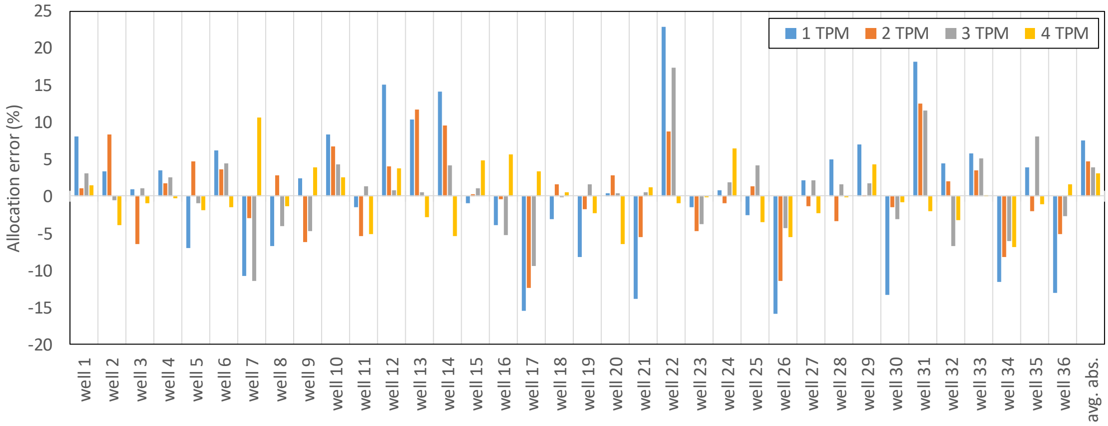

Figure 13: The change of allocation errors for individual wells in Case C when the number of tests per month is increased. Avg. abs. denotes average absolute error of all wells. Although, the average error shows a continuous reduction, the trend of errors for individual wells is not the same.

Although the average error decreased with more flow tests per month, the same trend is not seen for all individual wells. While for Wells 10, 31, and 36 a decreasing trend in the absolute value of the errors in seen, the rest of the wells have a random trend. Well 22 has had the largest error of all for one test per month (TPM) which has been 22.92%. It has gone down to -0.91% for four TPMs. The largest negative errors are those for Wells 26 and then 17 with -15.94% and -15.46%, respectively, associated with one TPM. It can potentially mean over 15% of the value of their yearly production does not go to their owner but to the owners of other wells. For one TPM, there are seven wells which have negative errors larger than -10%. There are just two wells that have the same condition for two TPMs. For three TPMs and four TPMs it decreases to one and zero wells, respectively. Therefore, the allocation is ‘fairer’ when there are more TPMs as it is also approved by the average values in Figure 13. Figure 13 also shows the largest errors occur under a different number of TPMs. Despite the falling trend, the largest error increased from two TPMs to three TPMs. When many cases are analysed, however, the overall trend is expected to fall. Therefore, the above exercise was repeated 100 times with different sets of random numbers (i.e. different well production rate fluctuations) to examine it. The results approve the expectation as shown in Figure 14.

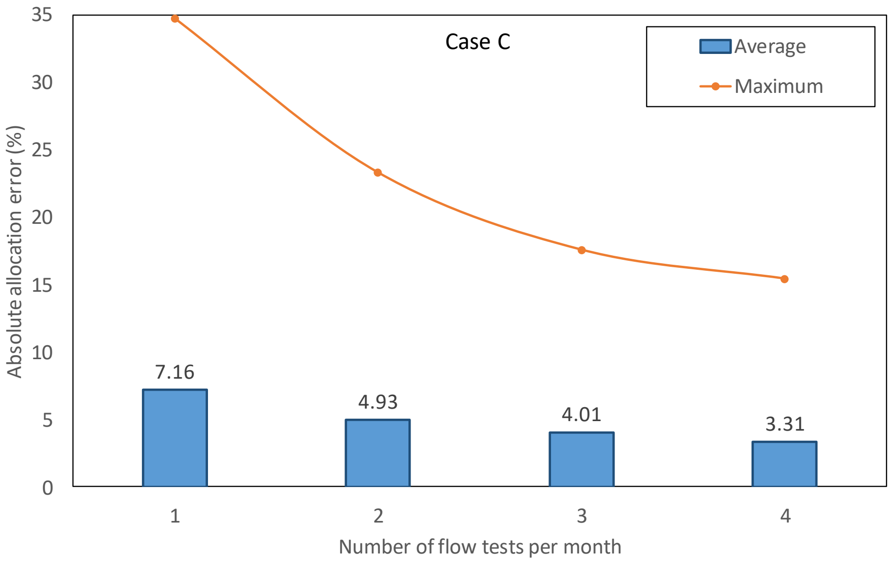

Figure 14: Maximum and average absolute allocation errors of individual wells in 100 allocation calculations for Case C when one to four flow tests per month are undertaken. The trends of both average and maximum errors are falling.

Figure 14 suggests that performing more flow tests on individual wells not only is important in hydrocarbon accounting, but can also be effective on reservoir management. Although the average absolute error of all wells for one TPM might be negligible (7.16%) in reservoir management compared to other large uncertainties in a reservoir, the errors of individual wells that can go up to 35% cannot be ignored. Therefore, decreasing the maximum error for individual wells through performing more frequent flow tests can play a role in having improved reservoir management and increase the oil and gas recovery. The best results in theory, however, are achieved when each individual well is equipped with an MPFM which can provide accurate continuous real-time data.

Conclusions

In this research, the effect of the frequency of performing flow tests for individual wells on their Estimated Total Production (ETP), allocation errors, and hydrocarbon accounting for the whole field was studied. The near-continuous real production flow rate data of three actual wells was employed to investigate how increasing the number of flow tests per month (TPM) can reduce the uncertainty in estimating total production of each well. Results showed that for wells with largely dispersed production data (i.e. flow rates with large fluctuations), there is a larger error in ETP. Increasing the number of TPMs, however, can significantly reduce ETP errors. For the well with the largest data dispersion in this research, the ETP error was reduced from 45% to less than 2% when the number of TPMs was increased from one to four.

In order to investigate the effect of the number of TPMs on allocation errors and hydrocarbon accounting, the production data of a simulated oil field with 36 production wells was analysed. The same data dispersion as the three actual wells was applied to the simulator outputs using the relative standard deviation of the actual data to make three cases similar to the real situations. Allocation and hydrocarbon accounting calculations for one, two, three, and four TPMs were subsequently undertaken for all the cases using a Matlab code. All calculations were repeated 100 times to secure reproducibility of the results and to provide the opportunity for statistical analysis. The results show larger average allocation errors and also wider ranges of error for higher RSDs. The average allocation errors were 0.85%, 1.05%, and 3.58% for RSDs equal to 0.007, 0.060, and 0.312, respectively, when there was only one TPM. These errors lead to $36M (Million), $44M, and $150M total yearly cost for the whole field for the respective cases. The results show that increasing the number of TPMs from one to four can reduce the allocation errors to 0.21%, 0.36%, and 1.64% which are respectively equivalent to $27.1M, $29.0M, and $80.1M reduction in the total yearly allocation cost for the whole field.

There can be operational constraints and capital and operating costs involved in undertaking more frequent flow tests in some fields. Moreover, as the analysis of the errors for individual wells has shown, all owners who have a share of the total production might not benefit equally from more TPMs. However, the results show that when there are more TPMs, the total cost for the whole field is reduced, hydrocarbon accounting calculations are more accurate, there is a fairer allocation of the total production to individual well owners, and there is less uncertainty in the production data used in reservoir management.

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Nomenclature

$AE\%$	Allocation error (%)
AF_k	Allocation factor for well k
ATP	Actual total production (STB)
$CP_{\Delta t_{i+1}}$	Cumulative production over the $(i+1)th$ time interval (STB)
$\mathbf{D_{ref}}$	Vector of reference production data (STB/day)
$\mathbf{D_{sim}}$	Vector of the production data from the simulator (STB/day)
DF	Vector of dispersion factors
E_{ETP}	Estimated total production error
ETP	Estimated total production (STB)
MPFM	Multi-phase flow meter
m	Total number of contributing wells
n	Number of data points
$\overline{Q}$	Average flow rate of the well during the test time (STB/day)
Q_i	The *i-th* measured flow rate data point during the test (STB/day)
Q_{t_i}	Production flow rate at the time t_i (STB/day)
RND	Vector of random numbers between zero and one
RSD	Relative standard deviation
ref	Reference data
SD	Standard deviation
$SD_{\mathbf{RND}}$	Standard deviation of the **RND** vector
STB	Standard barrel
TP_{field}	Total production of the whole field (STB)
TPM	(Flow) test per month
t	Time (day)
test	Test results
x	A single data point
$\overline{x}$	Average of all data points

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