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OPINION:
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Digital transformation in the oil and gas sector: a reality and a path of no return

Special: 25 years of the Oil Law

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Special issue

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RD&I: SUCCESS IN TECHNOLOGICAL PROSPECTION • THE GREAT ARTIFICE OF THE PETROLEUM LAW

THE CHALLENGE OF DIGITAL TRANSFORMATION

ARTICLES

A strategy of verification and validation of downhole equipment, by Cleber Pagliosa**; A digital transformation journey in flow assurance,** by Marcia Cristina Khalil de Oliveira, Rogério Leite Alves Pinto and João Neuenschwamder Escosteguy Carneiro

A DIGITAL TRANSFORMATION JOURNEY IN FLOW ASSURANCE

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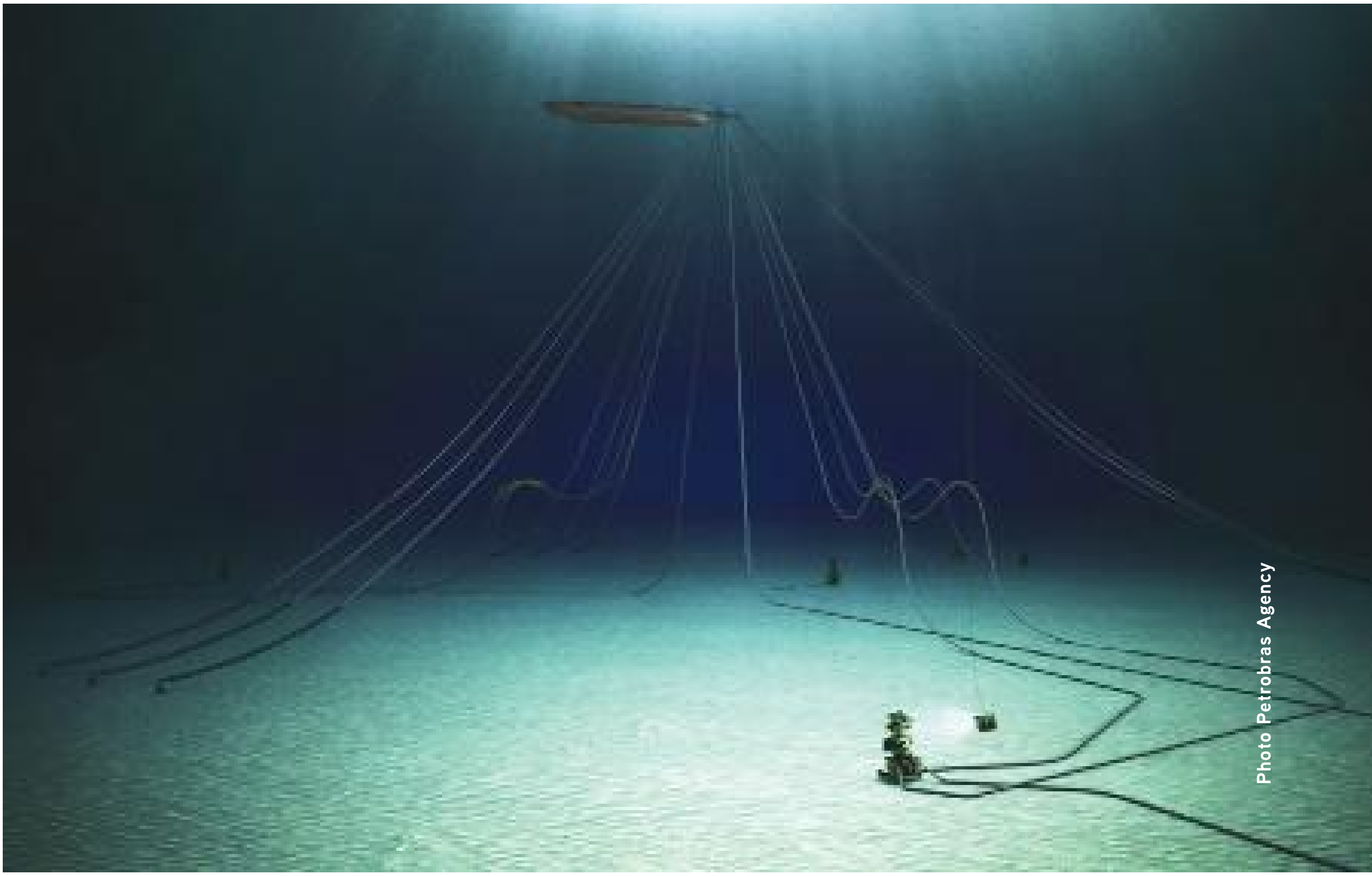
The term Flow Assurance was coined by Petrobras in the early 1990s in Portuguese as Garantia do Escoamento, meaning literally "Guarantee of Flow", or Flow Assurance. The Flow Assurance discipline is concerned primarily with the safe and economical flow of oil and gas from reservoir to the end client, through the complete lifecycle of the field.

The Flow Assurance activity is dedicated to studies on the chemical, physicochemical and thermodynamic phenomena that occur during oil production, and also to propose technological solutions to prevent or remediate the problems. Flow Assurance needs to cover a wide range of engineering fields, playing a critical role in all phases of the project.

At the beginning of oil and gas production in deep and ultra-deepwater scenarios the concepts of flow assurance became more important due to the adverse environmental conditions. Indeed, the high investments on installations and the high costs of interventions to solve flow restrictions or subsea flowline blockage problems impose significant economic losses to operators.

The reservoir fluids are exposed to severe pressure and temperature variations along the flow path to the platform that can lead to the formation of organic, inorganic or mixed deposits and can cause production impairments or even a complete flow blockage. The most common occurrences are caused by the formation of gas hydrates, wax deposits, viscous emulsions, inorganic scale and also by flow transients or instabilities (Marques, Gonçalves and Oliveira, 2018).

Traditionally, the way of dealing with flow assurance issues is based on the fluid characterization analyses, in thermodynamic simulation modeling, and in the thermo-hydraulic evaluation of the production scenarios. These analyses allow the specification of the installations design, materials and chemicals, and operational procedures, such as production and safety control systems, well architecture, top-side facilities, chemicals injection flowlines, equipment for the removal and collection of solids, flowline thermal insulation, among others.



It is often impossible to mimic in the laboratory the exact conditions occurring in the field and at the proper scale of the production system. Hence, since the inception of the flow assurance discipline, the "digital representation" of the production systems and flow assurance simulation models have always been an important part of the petroleum engineer toolkit to support the field design and operations.

Over time, these models have evolved following an improved understanding of flow assurance phenomena, from the smallest scales such as the precipitated crystals that may or may not cause an issue, to the large solid agglomerates that can block the flow passage completely. The simulation capabilities have also improved significantly in the last years, with better software products as well as increased computing resources available to the engineers. These tools now allow a much better risk assessment and improved design and operational practices.

In the last years, the application of Big Data in the oil and gas industry has also gained prominence as the amount of data generated and made available to engineers has significantly increased. Many engineering disciplines, including flow assurance, are now utilizing Big Data analytics to improve field practices operations. The advancement of data platforms capable to handle production data in a reliable manner has represented a significant step forward. Production management systems can now leverage on this potential to incorporate a wide range of applications to improve flow assurance digital workflows.

In this article, several applications will be detailed, combining flow assurance simulation models, data platforms, data science and artificial intelligence tools, for production monitoring and optimization, flow assurance digital twins and virtual flow metering solutions.

PRODUCTION MONITORING

Well production monitoring can be accomplished by two different processes. One of these processes is the monthly analysis made through the production tests history, while the other is daily analysis follow up observing the variations of the sensor gauges installed in the well and/

or in other parts of the production system.

The follow-up process through the production test history is based upon the comparison of the results of the production test and the ones obtained from a calibrated multiphase flow simulator. To perform a production test, the well is aligned to the test separator and then oil, water and gas flowrates of the well can be measured. Generally, the models can accurately represent the well flowrates, pressures, and temperatures under stabilized conditions (steady state). Some adjustments must be made to calibrate the model to mimic the production test history.

Once a calibrated simulation model has been obtained, it is possible to identify production deviations as new production test results start to diverge from the calibrated model, indicating that there is a problem. In some cases, the problem may be associated with test accuracy itself or the inability of the model to represent the new operational condition of the well. Discarded these two hypotheses, one can conclude that the well presents some production problem that must be identified and solved.

In the recent past, this whole process was carried out manually and without traceability. The test report used to be manually filled by the production operator; test report was sent by e-mail to the engineer; test report was often printed and checked by hand; test report data was fed into the simulator for engineer validation; test report data and production potential data were manually fed into another system for history recording purposes; the engineer's technical advice was sent to the operation team by e-mail.

The advent of digital transformation has allowed many advances in this process such as speeding up the completion of the test report and the analysis made by the engineer. It has also ensured the traceability and integrity of information throughout the process.

These days, much of the test report data is already automatically populated from integration with other systems. The system has a process flow for filling, verifying, and validating the data which ensures the quality and integrity of the information.

Test data is consumed by another system that helps the engineer interpret the quality of the test from the wellness of the well production perspective. It is also possible to automatically upload the test data into the simulator, make specific adjustments to the models, issue a digital technical advice on the behavior of the well production, and send the technical advice automatically to the operation team.

Another great advantage is that this huge amount of structured data can be used to develop dashboards and new intelligent algorithms based on data science which can further facilitate the engineer's task.

PRODUCTION OPTIMIZATION

From the models adjusted and calibrated with the production test results, it is possible to simulate operating conditions different from the normal ones. A very relevant process in this sense is the production optimization. The commingled production of several wells to the platform has some treatment capacity restrictions that shall be considered. Having the simulation models adjusted, one can run optimizers to seek the oil production maximization respecting all the production system constraints.

The classical approach to solve this problem is to run the optimization tools during well test analysis on a monthly basis. If the production of a well changes for some reason, these tools are able to optimize the operational condition of all wells of the platform to maximize the production. A gap in this classical approach is that operational problems in the topside and subsea systems may require new optimization runs. This ends up being done by the engineers on demand, but the response time can be high depending on the availability of the data and the engineer's analysis itself.

A modern approach is a real-time optimization where the optimization tool can automatically run the models considering the new constraints imposed due to an operational problem. A practical example is gas lift optimization. In case one of the compressors unit shutdowns, the optimization tool recalculates the optimal gas lift distribution to the wells to minimize the production loss associated with the compressor shutdown.

Depending on the level of reliability of this type of solution, it can be imagined that soon it might be possible to integrate it with the supervisory system of the platform to automatically drive the opening and closing of the well gas lift choke valves, improving the optimization process to its maximum level.

DIGITAL TWINS

Regarding multiphase flow models running in real time, the

so-called simulation digital twin, that is, a digital model capable of representing the physical model and simulating its operating conditions in real time. Obviously, this is a much more complex process, and it requires much more powerful tools. Starting with transient multiphase flow simulators that need to solve the flow equations with operating conditions that may vary in time. It is also necessary to read the sensor data and the status of the wells control valves, both on surface and subsea, to be able to emulate the well production condition.

Digital twins are typically able to provide 3 modes of operation: real-time mode; look ahead mode; and what-if mode. In real-time mode, it is possible to obtain information from the well at pre-defined frequencies, and from there to make analysis about its operational condition. In look ahead mode the system speeds up simulation so that the user can do an analysis in a near future condition. The what-if mode, the system allows the user to simulate some maneuvers in the well and make an analysis of the possible consequences of that maneuver before performing it in the well.

Suppose that a certain well is producing on a steady state condition. At some time, there is compressor shutdown and the well starts to receive less gas lift than usual. A few hours later a production shutdown occurs, and the well is closed. The real-time mode can emulate the flow reduction caused by the compressor shutdown and ensure that the initial condition of the well shut in is as close as possible to the actual condition. The look ahead mode can tell you if the fluids produced will enter the hydrate envelope, for instance, and how long they will remain inside it. What-if mode can be used to verify if the depressurization of the production line is sufficient to remove the fluids from the hydrate zone or not.

Digital twins are being widely used in various areas of the oil and gas industry and it could not be different in the flow assurance area. This is a very promising technology that has enormous potential to help operate wells in a safe and optimized manner. They can also contribute to the training of engineers and operators by simulating real conditions and providing experience of practical situations in controlled environments.

Recently, a Flow Assurance Digital Twin software has also been developed based on the accumulated experience in the intrinsic characteristics of the Brazilian Oil and Gas production systems, to monitor the flow assurance occurrences in real time. The tool allows a panoramic view of the flow assurance problems and works monitoring a defined data package. As part of a continuous learning process, lessons learned can be adapted and/or improved to be used continuously to setting the guidelines of production projects.

The software is a web tool that uses the Multiphase Virtual Meter data (MVM), the E&P Integrated Database, and some production software, and alerts the platform's supervisory system about the flow assurance risks. Furthermore, the production data are monitored by sensors in the field and integrated with data from specific laboratory fluid analyses and thermodynamic simulation models for predicting the subsea flowlines plugging risk.

Based on this information, and on the algorithms defined for each type of occurrence, the system shows the critical zone of wax deposition, alerts the potential risk of hydrate formation, shows the drag reduction and flow instability associated with viscous emulsion formation, monitors production downtime, exhibits the thermo-hydraulic profile of production scenarios and the identification of critical points associated with the inorganic scale formation.

The main benefits of this tool are the increase in operational efficiency, reduction of production losses resulting from flow assurance occurrences, significant reduction in the time for decision making in relation to a production management, availability of data in real time (office and field) and reduction of operational expenditure (OPEX). This software will be presented at the Rio Oil Gas Conference 2022 (Oliveira et al. 2022).

VIRTUAL FLOW METERING SOLUTIONS

As seen above, well flow metering is a fundamental process both from the production and fiscal allocation standpoints, as well as for production optimization purposes. The understanding of how much oil, water and gas are being produced in each well is also important for flow assurance engineers, in order to determine the risks of slugging, corrosion, erosion and defining how much chemicals to be injected per well, for example.

Multiphase flow metering technologies can be divided into three main categories: in-line flow meters, separation flow meters and virtual flow meters (VFMs). The first category performs direct measurement in a multiphase line without sampling the phases. Because they need to be placed in each well, the downside of this option is that it requires CAPEX investments, and needs to be maintained and calibrated, making sure that the sensors are working properly. The second category relies on full or partial separation, after which single phase meters are used for individual flow rates characterization.

Test separators are the most common example of this kind. Separation flow meters are usually more accurate, however require some production deferment to flow each single well to the test separator, which means that production transients cannot be captured with separation flow meters. Furthermore, the operational disruption and re-start is often costly and complex. This metering option may sometimes also not be feasible due to flow assurance issues, if a given well flow rate is too low, for example.

In virtual flow metering, the idea is to use existing sensors to infer the well phase flow rates. The advantage here is that no direct measurements are performed, with no need for additional sensors or hardware installations, being the most cost-effective solution.

Recently, solutions that combine physical flow meters with VFMs have also emerged. This allows to mutually enhance both metering technologies: the additional measured data can be fed as input to the VFMs, while the VFMs can aid the calibration process of the physical flow meters. Further advantages are: i) the possibility to combine lower cost, simpler devices that perform phase fraction measurements with the VFMs to provide full phase flow rates; ii) VFMs may allow to perform data reconciliation of the in-situ physical measurements with the remaining sensor data from the production system.

There are two main types of VFMs: data-driven VFM or physics-based VFM. In the first type, flow rates are inferred through statistical processing of the sensor signals and the use of machine learning algorithms; the second type relies on physical models to simulate the well conditions. One may further subdivide physics-based VFMs in steady-state and transient VFM, depending on the application of steady-state or transient multiphase flow models.

In both cases, one may need to simulate the well thermal-hydraulic behavior using available field measurements to set boundary conditions (typically pressure downstream the choke and choke positions), obtaining the desired flow rates. To construct such a model, however, one requires substantial amount of information on the production system: reservoir P&T and productivity index, well elevation profiles, pipe IDs and wall layers, wall roughness, heat transfer coefficients, external thermal profiles, among several other parameters, in order to remain true to the field configuration and operating conditions.

The model inputs may require a certain degree of calibration, which can be done using other sensor measurements such as p and T bottomhole and at the well head, as well as well test results. This can be done offline (manually) or online (automatically), depending on the required frequency, and the capabilities of the production management system.

A fundamental aspect to be addressed is that the fluid properties play a very important role in this type of VFM. In such physics-based systems, if good estimates or measurements of fluid properties are not available, the simulation results are doomed to possess high uncertainty. Two important input parameters related to the fluid properties are the GOR and Water-Cut, which need to be provided to the model and typically require adjustments.

Another point to consider is that physics based VFMs are usually complex software platforms with sophisticated mathematical equations and may present disruptions, either due to numerical convergence issues, or, since they are usually installed at the production facilities, often requiring third-party licenses, simulator downtime may be caused by certain operations performed in the computing servers (maintenance, updates, etc).

In data driven VFMs, machine learning algorithms are used to try to find correlations between available sensor measurements (inputs) and phase flow rates in each well (outputs). After a VFM has been trained and deployed, such correlations are represented by direct algebraic calculations and thereby have no convergence issues, require no high-end hardware, are very fast and largely scalable (it is possible to have thousands of machine learning models deployed in the same piece of hardware, which does not necessarily require high performance computing capacity).

Finally, dependency on fluid properties is not an issue; on the contrary, data-driven VFMs may in fact also be used to estimate some fluid properties required by physics-based VFMs. The biggest challenge with data driven VFMs is the need for large amounts of good quality field data to train the models, which is usually not the case in green fields, or for a new production well, where there is little to no historical data. Furthermore, large volumes of missing or faulty sensor measurements are recurrent. Ideally, a comprehensive data set in the expected operating conditions for a given field or well is needed to train a model, including full range of variations of choke openings, flow rates, GORs, WCs, among others, but these may not have happened yet.

HYBRID SOLUTIONS

In the above context, the advantages and shortcomings of each method motivates the development of yet another type of virtual metering solution: the "Hybrid VFM". Here, one may use a subset of field data to adjust a physics-based model and use that to generate a large amount of synthetic data of the full range of operating conditions and fluid properties expected for the production system. The simulated data complements the field sensor data in a combined dataset used for training the machine learning models. These types of models can also provide insight into physical quantities that are typically not measured by the field sensors. This may be very important also to monitor and assess flow assurance risks. One example of a hybrid system to monitor the GOR in a pre-salt field is that of Scramignon et al. (2022), to appear at the Rio Oil and Gas Conference 2022.

Another application where data-driven models trained by existing sensor data alone will also have difficulties to perform well is the example of monitoring the hydrate blockage risks in an oil production well. Hydrate plugging during a shut-in / restart, for example, is result of a set of complex phenomena influenced by several processes and variables, many of which are not measured directly, such as: the amount of water or gas accumulated in the flowlines due to terrain undulations, the sub-cooling history of the mixture inside the hydrate envelope and how long did those conditions occur, what is the local inhibition achieved along the flowline, among many others.

Such information can be retrieved from high fidelity physics-based model to feed hybrid machine learning algorithms that can monitor the hydrate plugging risk in real time. Models of kinetics, agglomeration and transport of hydrates have been developed and improved by researchers and engineers, which are now being incorporated into commercial simulators. This will support the application of the digital twins as a powerful tool to help in the hydrate management and the risk prediction of hydrate blockages.

A very important topic to be addressed when developing machine learning models to monitor and detect anomalies in oil wells is the availability of relevant data for model development and training purposes. While field production data is often regarded sensitive by operating companies, some initiatives do exist that aim at providing data to researchers and engineers working with data science and artificial intelligence.

The 3W dataset (https://github.com/petrobras/3W), for example, is an innovative initiative that aims at providing a realistic and public dataset with undesired events occurring in offshore oil wells to be used as benchmark to develop machine learning techniques for predictive purposes (Vargas et al. 2019). This and other initiatives by operating companies contribute towards democratizing data access in order to leverage the full power of data-centric engineering approaches for the benefit of improving their own operations.

FINAL REMARKS

The natural mindset for the flow assurance activity is to prevent flow assurance issues from occurring. Just as the HSE area constantly seeks to avoid accidents, the flow assurance activity seeks to avoid occurrences that affect the well flow, minimizing production losses and maximizing throughput. However, unlike the HSE area that cannot tolerate new accidents, the flow assurance activity may tolerate the presence of some flow assurance occurrences, as long as they are under control.

Thanks to the advances in: i) understanding the basic mechanisms governing the flow assurance issues occurring in the field, ii) translation of those into mathematical models and commercial simulation software available to the market, iii) increase in field data recording, quality and availability through advanced data platforms, iv) advances in data-science and artificial intelligence; the flow assurance engineers and the field operators are now equipped with a set of powerful tools that support the strategy of minimizing flow assurance risks while adapting a flow assurance management perspective rather than complete avoidance, alleviating the need for overly conservative approaches that often increase operations cost and complexity in a prohibitive manner. ■

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