Reservoir Modeling and Production Solutions Help Reduce Exploration Costs by Up to 20%

aspentech | Case Study

> “This project allowed us to better understand the specifics of the field and set new priorities for the exploration program.”

Managing Director, Major Oil & Gas Operator, Caspian Sea Region

CHALLENGE

Assess the economic feasibility of a gas field development project, and design an exploration and research program that would reduce uncertainties and risks.

SOLUTION

AspenTech Subsurface Science & Engineering (SSE) solutions were used to test and simulate different scenarios in field development, including Aspen Big Loop™ to perform uncertainty and risk estimation as part of the project feasibility, with Aspen Tempest ENABLE as an orchestrator. The loop included geomodeling in Aspen RMS™, reservoir flow simulation in Tempest MORE, and flow simulation in wells and surface networks in Aspen METTE™.

VALUE CREATED

- Economic indicators of the tested scenarios showed that the decision to continue exploration drilling was correct.
- The conclusions led to a change in research priorities, to focus initially on studying fracture properties.
- The company concluded that the targeted research into the key uncertainties could reduce the cost of the surveys in new exploration wells by up to 20% without losing useful information.

Overview

The customer is a major operator providing oil and gas exploration and extraction services in the Caspian Sea region (Figure 1). The customer needed to assess the feasibility of investing in the development of a gas field and designing an exploration and research program that would reduce uncertainties and investment risks.

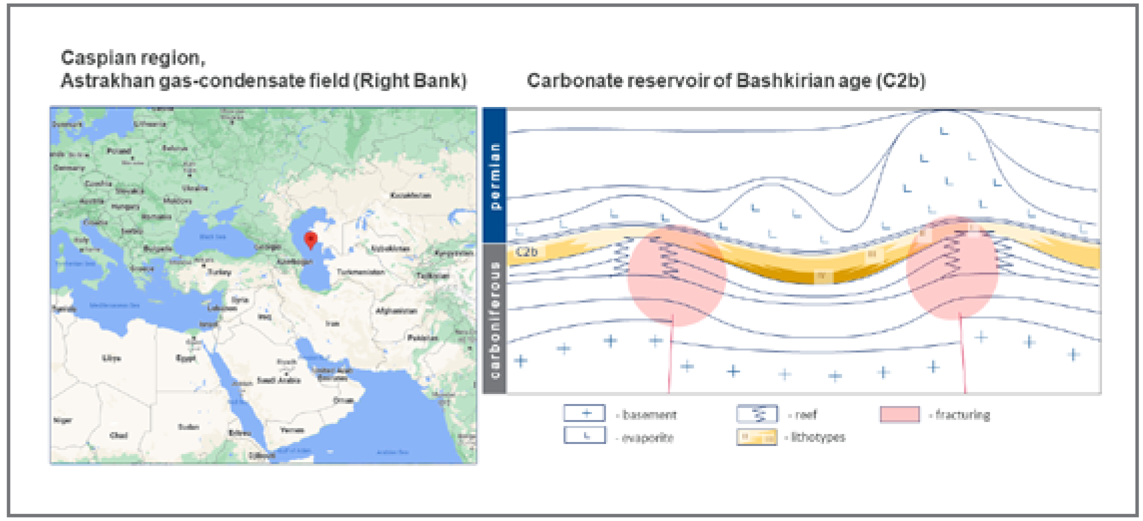

Figure 1: Gas-condensate field.

The gas-bearing reservoir is a massive fractured carbonate formation of Bashkirian age (C2b) with relatively low matrix permeability. Based on the development history of neighboring fields, it was assumed that the gas flow runs mainly through a network of fractures, providing acceptable flow rates as well as fast water breaks in production wells. This assumption needed to be considered in the production forecast.

Six exploration wells drilled in the area in the 1980's were represented by a small set of logging and core analysis data. The only well with a comprehensive survey that included FMI and Sonic Scanner (techniques to study fracturing), was drilled in 2020. This data was not enough to reliably forecast production even with 3D seismic data covering the entire study area. For two additional exploration wells that were planned to be drilled in 2023-2024, the company was looking to reduce survey and research costs without compromising quality. There was a need to define the well locations and design the research program to maximize efficiency by reducing uncertainties.

Since high-velocity gas flow was expected in the production wells, it was important to simulate the fluid flow not only in the reservoir but also in the wells, to take into account pressure losses caused by friction. The high proportion of acidic components (SO2, HS) in the gas suggested a need for stricter constraints on flow rate in the wells and in the surface pipeline network to avoid destroying the inhibitor film preventing metal corrosion.

A Complete Workflow Delivering Reliable Results

Ensemble simulation utilizing the Aspen Big Loop technology was used to perform uncertainty and risk estimation as part of the project feasibility assessment, with Aspen Tempest as an orchestrator. The loop included geomodeling in the Aspen RMS reservoir modeling suite, reservoir flow simulation in Tempest MORE, and flow simulation in wells and surface networks in the Aspen METTE production modeling solution (Figure 2). A set of static and dynamic variables were defined: average NTG, average porosity, coefficient in the equation Perm = F(Poro), coefficients in the Corey correlation for relative permeabilities in a gas-liquid system, average fracture aperture, coefficient in equation describing the relationship between pressure drop and permeability deteriorating, etc.

A DFN (Discreet Fracture Network) model (Figure 3) was built as part of an automated workflow in the Aspen RMS project to account for the impact of fractures on reservoir permeability. The contribution of fracturing to reservoir permeability was mainly defined by such characteristics as fracture density, average length, orientation and average aperture. The latter varied in model realizations. The summarized permeability of the rock matrix and fracture network was exported to the reservoir flow simulator. Pressure losses and flow rates in the wells and the pipeline network were estimated and controlled by the Aspen METTE simulator (Figure 4).

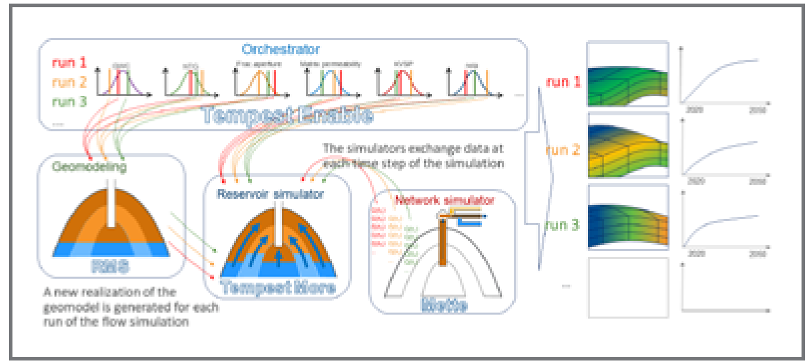

Figure 2: Big Loop configuration.

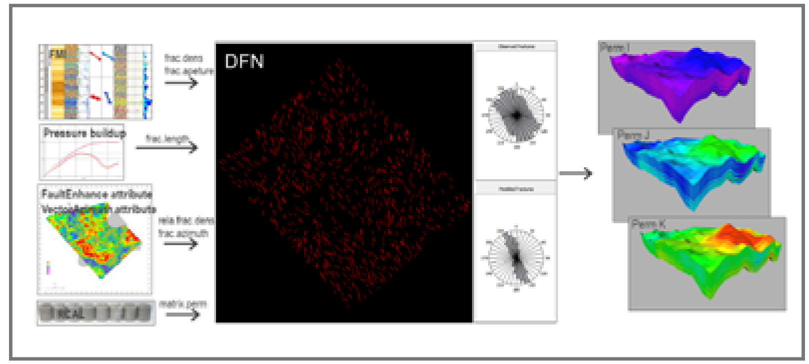

Figure 3: DFN Modeling.

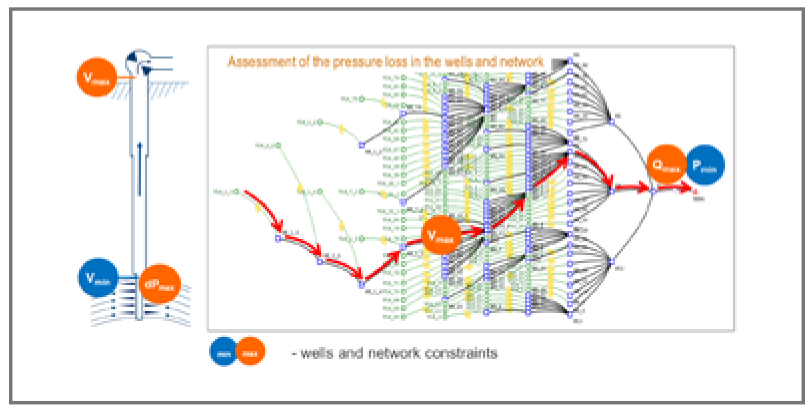

Figure 4: Flow simulation in wells and surface network.

Thorough Analysis Led to a Change in Research Priorities

Production profile ensembles were generated for all tested scenarios of the field development. Estimates of total gas and condensate rates P10, P50, P90 were derived from the ensembles and used in economic calculations. Finally, economic indicators for P10, P50, P90 estimates of all tested scenarios were calculated and analyzed. Although some scenarios showed promising figures in the P50 estimate, the significant difference between P50 and P90 estimates indicated high risk, proving the correctness of the decision to continue exploration drilling (Figure 5).

Analysis of the sensitivity of the cumulated gas production to the applied variables showed a high contribution to the forecast uncertainty of both volumetric parameters and those related to flow capacities (Figure 6). But the latter, especially fracture aperture, played a major role in the first several years of development. That makes this parameter a key uncertainty factor in terms of project economics, given the reduced cash flow.

This conclusion led to a change in research priorities, with an initial focus on studying fracture properties. A combination of geophysical well surveys to study fractures was proposed, and a machine learning algorithm (MRGC in Aspen Geolog™) was successfully tested to distinguish between reservoirs with different types of porous media: those with mostly intergranular porosity vs. those with mostly fracture porosity. For these types of reservoirs, individual programs of formation testing and core analysis were designed to provide data for subsequent simulation of dual media.

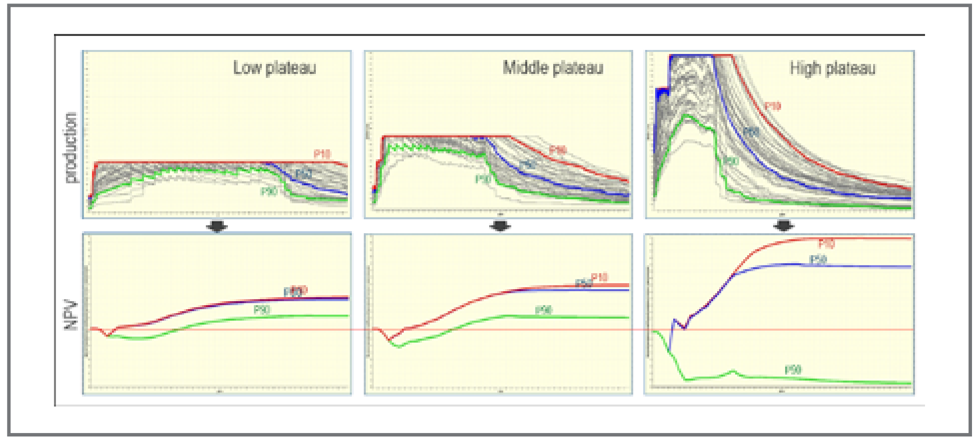

Figure 5: Assessment of development scenarios.

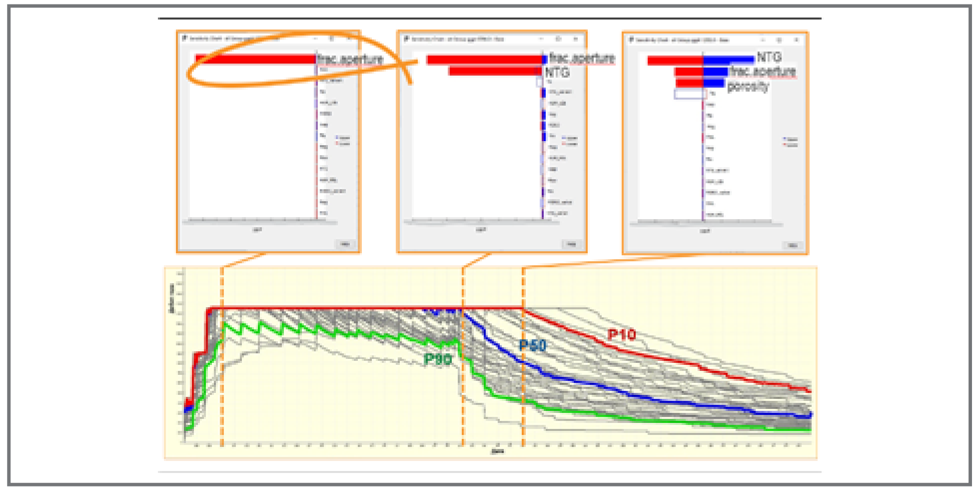

Figure 6: Sensitivity analysis.

Conclusion

The company concluded that the scope of the research program in new exploration wells could be reduced by up to 20% without losing useful information, by focusing on the most significant uncertainties affecting the quality of the production forecast.

About AspenTech

Aspen Technology, Inc. (NASDAQ: AZPN) is a global software leader helping industries at the forefront of the world's dual challenge meet the increasing demand for resources from a rapidly growing population in a profitable and sustainable manner. AspenTech solutions address complex environments where it is critical to optimize the asset design, operation and maintenance lifecycle. Through our unique combination of deep domain expertise and innovation, customers in capital-intensive industries can run their assets safer, greener, longer and faster to improve their operational excellence.

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