USING DYNAMIC, INTERNET-ENABLED RESERVOIR SIMULATION TECHNOLOGY TO ENHANCE ONGOING RESERVOIR MANAGEMENT AND FIELD DEVELOPMENT

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ABSTRACT

By coupling the communications power of the internet with the latest in reservoir simulation technology, it is now feasible to direct oil and gas field development in near real-time, using a continuously updated computer model that matches and reflects the actual rates and pressure data observed in the field. While quarterly or monthly updates are probably sufficient in most cases, operators have the option of updating the model weekly or even daily in order to meet the needs of each situation. This ground breaking approach can remove much of the risk from evaluating well completions, optimizing the location of offset and infill wells, predicting reservoir pressures, flow rates, reservoir drainage patterns, identifying the most effective completion methods, well spacing patterns and many other field management decisions.

This paper illustrates how this kind of dynamic reservoir simulation can be implemented, even for small, remote production locations, and it cites examples of where this has already been tried, the results that were obtained and describes the experience of those who have actually implemented this approach. The capability now exists for operators, regardless of size or location, to model every new development well (prior to drilling), identify the most cost-efficient reservoir drainage plan and adjust that plan in an ongoing manner based on actual field/well behavior.

INTRODUCTION

Once a pool of oil or gas has been discovered, the focus shifts to figuring out how to develop that reservoir in the most efficient, cost-effective manner. To do that, an operator must determine with reasonable certainty the optimum location and spacing of each new infill or offset well, how those wells should be completed and how they should be operated once they are brought on line. And to do those things, he must gain a reasonably good understanding of the reservoir, itself, in order to be able to predict how it will respond to any given development plan. Because the behavior of the reservoir and individual wells often vary significantly over time due to the interference effects of new wells and increasing depletion, it is normal for field development plans to require significant modification to obtain an optimum long term result. In order to predict and respond to these real changes in well and reservoir behavior over time, an operator would have to create a detailed, computerized model and continually update it with current, observed data to ensure that it always reflected the physical realities of the field and that his development plan still made sense in light of the latest information. By monitoring well and reservoir behavior in this manner throughout the entire field development cycle, an operator could dramatically improve his ability to achieve maximum drainage for the lowest cost in the shortest amount of time.

Since time, data, manpower and cost constraints make conventional simulation prohibitive for all but the largest fields with high reserves, only a small percentage of development wells are ever modeled before they are drilled and many other day-to-day problems are never even addressed. Consequently, most development decisions are now made without any predictive modeling whatsoever.

However, new rapid simulation technology, coupled with internet communications, now makes it possible for operators to engage in "dynamic" field management based on computerized reservoir models that are continuously updated using observed data from the field. This paper will explain how such a program can be implemented by virtually any operator, regardless of field size or location.

PRACTICAL OBJECTIVES AND CONSTRAINTS

Most operators clearly would like the capability to:

- Make pressure, volumetric and flow rate predictions with a high level of accuracy;
- Model all new development wells before drilling;
- Automatically update models on a regular basis so they always reflect current observed results during field development;

- Cut the (operator's) time required for modeling to no more than one day per field per month;
- Provide rapid, unambiguous analysis and reports, including tabular, graphical and 3D visualization data, to the production, exploitation or reservoir engineer in charge of the project;
- Evaluate multiple development plan options which consider flow rate, pressure, economic, volumetric and material balance analysis and projections; and
- Do all of the foregoing regardless of location (i.e. remotely over the internet) with the expenditure of very little time and effort from the project engineer and in a very cost-effective manner.

Stand-alone reservoir simulation studies typically provide brief "snap-shots'' of the condition of the field, which only remain valid for a short time before they must be updated to reflect the actual experience of new wells and other ongoing field development activities. To address the objectives identified above, ***the model must evolve*** in synchronization with and as a reflection of actual field development, thereby providing the operator with regular, periodic (monthly, weekly, etc.) updates and assuring that the predictive model always accounts for the most current observed information from every well ***as the field is being developed.*** Although conventional grid-based simulation methods are well suited to perform large, complex studies for which time and expense constraints are not limiting factors, they are unsuitable for use in solving many smaller problems for a large number of wells in different areas on an ongoing basis. In other words, ***conventional technology does not satisfy the foregoing objectives.*** However, a new modeling technology has emerged which eliminates the practical limitations of grid-based reservoir modeling while still generating fast and rigorously accurate solutions to many of the same types of problems.

ENABLING TECHNOLOGIES

The new simulation technology is based on the boundary element method (BEM) and it dramatically simplifies the entire modeling process by completely eliminating the necessity of building grid meshes to describe the reservoir. The result is an easy to build, fast running model that requires a remarkably small amount of data - data that is almost always available to any operator.

Once the initial model has been constructed, all subsequent data transactions (i.e. to feed the model and report back to the customer) can be handled via the internet. This process will be facilitated by electronic data forms and object files transferred through a secure web site or even as e-mail attachments. By coupling BEM modeling capabilities with the speed and availability of internet communications, dynamic reservoir modeling is now a viable option for virtually every operator, regardless of size or location.

IMPLEMENTATION PROCEDURES

Although there are several implementation options, we shall assume for now that everything is handled out of one central office. Here is how the typical case would work:

Step 1: Data needed for the initial model set up is entered onto electronic forms by the operator and sent to the "service center" through a secure web site or as an e-mail attachment.

Step 2: Using the reservoir properties, well properties and control parameters specified by the operator, a service center engineer constructs the model and generates a history match with the observed rate and pressure readings. If additional information or clarification is required, the service center engineer will contact the operator directly.

Step 3: Once a good history match has been obtained, thus assuring that the model reflects the physical realities of the reservoir and its existing wells, a "Default Scenario" will be run to predict pressures and production rates (daily and cumulative) for 5 years (or more) into the future based on the current mode of operation. This will become the standard against which all other potential development plans will be measured and evaluated.

Step 4: All of the foregoing results will be analyzed, summarized and made available to the operator using the internet facilities previously referred to.

Option: At this point, the operator may *(a)* determine for himself the location, spacing and completion method of the next development well(s), or *(b)* ask the service center to run one or more "what if' scenarios to assist him in making those decisions. Under this option, the service center engineer would model several alternative scenarios and report the production performance of each new well, the effect it has on the other existing wells, the resulting drainage patterns across the reservoir and the economic consequences for each case.

Step 5: After the base case is established, subsequent observed rate and pressure data is periodically downloaded (i.e. monthly) from the operator's electronic data source, parsed into the appropriate files and run through the model. Appropriate security, error controls and data validation measures are applied throughout the process.

Step 6: After the model has been updated and run, the BEM system will automatically check to see how closely the predicted results match the new observed data. If the match is within the normal, acceptable variance level, an appropriate message will be generated and returned to the operator, together with an updated forward-looking Default Scenario. If the match is not within the normal variance level, it will be flagged for inspection by a service center engineer.

Step 7: When an engineer sees a case that is not responding as expected, he will "tune" the model by adjusting the reservoir and/or well parameters until a good history match has been reestablished using the most recent observed data. Although this can normally be done by the engineer working on his own, he may also consult directly with the operator for further clarification, if necessary.

Step 8: Once the model has been properly adjusted to reflect the ongoing operations, the service center will rerun the case, make whatever adjustments are necessary to the current short term development plan, generate a revised Default Scenario and submit a report to the operator, including documentation of all the changes that were made to obtain the new history match, an engineering analysis of the new results, data, graphs and/or maps to support all of the foregoing and a recommendation of whether or not the existing development plan should be modified to account for this new information.

Ongoing: Repeat Steps 5 - 8 until the field has been fully developed and substantially drained.

SWAT Options: At any time, a proactive operator may ask the service center to run one or many "what if" cases, solve specific engineering problems or request more information concerning individual wells anywhere in the field. Because the model is continually refreshed with current data, answers to such questions can be obtained very quickly and inexpensively. Using this method, for instance, operators can determine the optimum completion (i.e. frac job) parameters in order to balance cost *vs.* production, assess the quality of a frac job after it is done, evaluate the current condition of a gravel pack, more closely identify and analyze short term trends, make performance predictions based on hourly tests, identify boundary locations, reservoir size and resolve a variety of other problems quickly, accurately and at very low cost that can be supported by realistic production levels.

Recap: This capability has never before been widely available due to the overwhelming technical, logistical and economic difficulties involved. The unique combination of SWARM technology and the internet have now eliminated these obstacles and make it possible to obtain this valuable service in a timely and highly cost-effective manner for virtually any field in the world, regardless of size or location.

BENEFITS OF REAL-TIME MODELING

As just stated, the efficiencies created by this approach would, for the first time, now make dynamic predictive analysis and field management a viable option for the vast majority of operators throughout the world. Because the model always reflect current actual rates and pressures, operators can quickly evaluate and optimize well locations, spacing, completion methods and the production potential of new wells, as well as generate economic profiles based on more accurate reserve analysis. It would also allow operators to address a wide variety of well-specific problems, which usually go substantially ignored, and permit them to adjust their drilling plans in an ongoing manner in order to optimize reservoir drainage.

This entire process would be "painless" for the operator, since it would, to a large extent, be automated after the initial baseline model is established. Updated model results and field development recommendations would be sent to the operator on a regular basis (i.e. monthly) for evaluation. If more frequent updates were needed, or if studies to resolve problems with specific wells were indicated, those options would also be available on a moment's notice and at very reasonable cost, because the operator always has access to an up-to-date model of this field. It is estimated that the cost of providing "standard" ongoing field modeling services (i.e. with 12 monthly history match updates, 12 predictive Default Scenario runs, which look ahead two years on a rolling basis, and the accompanying technical analysis and interpretation) would be only about 10% to 15% of the cost of obtaining a single conventional reservoir study plus one update at the end of the year for the same field. The cost of obtaining additional well-specific information as described above would then be incremental, as opposed to time consuming and often prohibitively expensive using any conventional grid-based system or consulting service.

By preventing the drilling of unnecessary wells, or by optimizing the location (and thereby improving the flow performance) of new wells, predicting the best completion strategy while considering well and boundary interference effects over time, or identifying the well spacing that results in the most cost-efficient drainage pattern across the reservoir, this unique process can easily return many times its own cost each year. Thus, the value proposition this technology and methodology bring to the participating operator is extremely compelling.

THE EOG RESOURCES EXPERIENCE

EOG Resources began using the BEM-based modeling process in 1999 and they have since constructed hundreds of reservoir models to examine cases ranging from single well performance evaluations to more complex field development questions involving many wells and multiple zones. It soon became apparent that this new approach to reservoir modeling enabled EOG to more closely examine a greater number of the company's wells and that the dynamic modeling process would be highly beneficial to the company, giving them a competitive edge in several areas. Among other applications, they use the model to:

1. Project the performance of new wells: This has been so effective that in some districts of the company, not a single well is drilled unless it is first simulated and evaluated using this process.

2. Optimize new well locations: Drainage patterns for in-fill and offset wells can be visualized and evaluated to better define expected long-term performance; this is especially important in estimating reserve values.
3. Evaluate current well performance: This helps EOG identify the best way to manage each well in order to realize maximum performance under current operating conditions.
4. Test performance projections: To make sure they are accurate and that our current reserve bookings are correct.
5. Make performance comparisons: The expected performance of a new well can be easily compared with actual performance (i.e. observed rate and pressure data), thus allowing us to quickly gain a better understanding of the reservoir and how it should be managed.
6. Assess the effectiveness of a frac iob or other type of completion: The model makes it very easy to evaluate the quality and effectiveness of the well bore skin, gravel pack or a hydraulic fracture length.

Prior to the introduction of BEM technology within EOG, less than 10% of their wells were evaluated using reservoir simulation, primarily due to time and data constraints and the lack of adequate training in the use of the simulation programs. After implementation of this program, the percentage of wells being modeled has increased to better than 33% company wide, and one district is modeling all (100%) of its development wells, which is the ultimate objective for the entire company. This increase in model-based evaluations has had a very significant positive economic impact on the company, as manifested by the smarter, more effective deployment of capital dollars through the drill bit, as well as by more accurate reserve evaluations. In one 14 month period, EOG calculated that the benefits-to-cost ratio attributable to this technology was well in excess of 50:1. Another collateral benefit of the technology is that it allows engineers across the company to discuss reservoir issues by exchanging model cases over the Internet. For those problems that justify the additional scrutiny, this allows us to benefit from a wide range of technical input, and do so on a very timely basis.
Based on the success of the BEM-based simulation program to date, EOG is developing the internal capability to predictively model most (eventually all) of the hundreds of new development wells that we drill each year. By building and maintaining reservoir models for all of our fields, they expect to be able to monitor and evaluate the performance of all their wells and to effectively direct field management activities on a continuous basis over the long term.

CONCLUSIONS

BEM modeling technology is a fast, accurate tool for creating and updating reservoir development simulations with near real-time speed. By coupling this technology with the internet, continuous and dynamic predictive analysis is now both ***physically and economically viable*** for the vast majority ofproducing fields in the world. This means that it is now possible, ***on a regular, ongoing basis,*** for an operator to quickly evaluate and optimize well locations and spacing, completion methods, the production potential of new wells and test various field development strategies. This type of dynamic, predictive analysis is feasible because updated information from the field can be readily obtained, quickly and automatically transmitted to and assimilated by the model, then analyzed, interpreted and the results delivered to the operator in a summarized, easy to read format. The big advantage of this unique method is that it continuously accounts for current information from the field – including data from new wells, recompletions, unexpected pressure or production changes, etc. – and enables the operator to anticipate problems, evaluate different possible solutions and adjust his field development plan accordingly.
As described above, the benefits to subscribing operators can be both substantial and immediate without being intrusive or time-intensive. While the primary analytical and interpretive services may be furnished by a remote service center, the operator’s own engineers can participate in the process and exercise complete control over all field development decisions. By providing in-house engineers with access to valuable analytical and diagnostic information that has never before been available, much more effective day-to-day drilling and field development decisions can be made quickly, with far greater confidence and at very low cost, with virtually no additional ongoing time commitment required from the local engineers after the initial set up is done.

This technology will play a prominent role in the future of oil and gas field management.

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