Appendix E - Reservoir Modeling Team 2010; Reservoir Modeling Report

Reservoir Modeling Team. 2010. Flow Rate Technical Group Reservoir Modeling Team Summary Report. August 11, 2010.

Note: This report was not previously released as a separate document.

Flow Rate Technical Group
Reservoir Modeling Team
Summary Report

August 11, 2010

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1. Overview

The Reservoir Modeling Team (Team) was established within the Flow Rate Technical Group (FRTG) to develop an independent assessment of the rate at which oil and gas can be produced from the sands penetrated by BP's Macondo well. Using open-hole logs; pressure, volume, and temperature data; core samples; and analog reservoir data; the Team directed the development of reservoir models from three independent groups of researchers from academia and other experts in the field of reservoir simulation. The researchers populated computer models and determined flow rates from the targeted sands in the well as a function of flowing bottomhole pressure.

The Nodal Analysis Team of the FRTG used reservoir modeling data (including pressure, temperature, fluid composition and properties over time), pressure and temperature conditions at leak points on the sea floor, along with details of the geometries of the well, BOP, and riser to calculate production rates from BP's well. The results of the Reservoir Modeling - Nodal Analysis study represent a scientific methodology that is independent of other FRTG methodologies that are being used to develop flow rate estimates.

2. Team Members

The Team is made up of engineers from the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) from the New Orleans Region Office and the USGS in Denver. BOEMRE personnel were responsible for obtaining proprietary rock, fluid and well data from BP and geologic interpretations of the target sands from BOEMRE geoscientists. The BOEMRE Team members were also responsible for conducting market research, assisting in developing formal federal contracts for the studies, assessing bid packages for the contracts, recommending selection of the researchers, and reviewing the deliverables for the Contracting Officer and FRTG. The BOEMRE members are Don Maclay, Gerald Crawford, David Absher and other Gulf of Mexico Region staff petroleum engineers.

The Team's representative from the USGS is Dr. Mahendra K. Verma, Research Petroleum Engineer at the USGS Energy Resources Science Center in Denver, CO. Dr. Verma's expertise in reservoir engineering and simulation allowed him to serve as an advisor in the area of reservoir simulation and as peer reviewer of the output data from the researchers.

3. Independent Researchers

Federal contracts were awarded to three independent research groups to conduct studies for the FRTG. These contracts were developed and executed in accordance with all federal acquisitions regulations which was required before work could begin by the research teams. This contracting process generally takes several months to complete; however, to expedite the process, a market research was preformed by the Team to justify other than full and open competition (JOFOC). By using the market research/JOFOC methodology, the time needed to award the contracts was reduced to three weeks.

The researchers selected for the project were as follows:

(1) Kelkar and Associates (University of Tulsa Group):
Dr. M. Kelkar, Professor, University of Tulsa, PhD Chemical Engineering, University of Pittsburgh,
Dr. H. Ates, Senior consultant, PhD Petroleum Engineering, University of Tulsa,
Dr. A. Bahar, Principal Consultant, PhD Petroleum Engineering, University of Tulsa.

(2) R.G. Hughes and Associates (LSU Group):
Dr. R.G. Hughes, Associate Professor, Louisiana State University, PhD Petroleum Engineering, Stanford University.

(3) Gemini Solutions (independent reservoir simulation firm):
Dr. J. Buchwalter, PhD Chemical Engineering, Rice University,
Dr. R. Calvert, PhD Biophysics, University of Houston.

The time given the researchers for their analysis, one to two weeks, was limited due to the timeline established by the FRTG. After allocating time for input data review, model construction, output data review and report writing, the researchers were left with only a few days to actually run the simulations. This was an extremely challenging schedule; however, the researchers were successful in providing the contracted deliverables as required.

BOEMRE supplied the input data, and due to the time constraints, required the researchers to focus on most-likely and worst case scenarios. The research teams were free to develop other scenarios testing sensitivities to a variety of reservoir parameters if time permitted. The research conducted by each team was independent of the other teams' analyses; the teams were not made aware that other groups were involved with the same project through BOEMRE. This was done to maintain a high level of independence among the research teams.

4. Input Data

The Team compiled and reviewed all pertinent reservoir and fluid information needed to perform reservoir simulation studies for the FRTG. The information included reservoir rock data, rotary core data, PVT data, bottom hole pressure transient data, the wellbore schematic listing all critical dimensions and depths, flow assurance wax and asphaltene analyses, geochemical analysis, mud log and CMR log analysis and raw log data. The same items listed above were also compiled and reviewed for an analog well drilled 20 miles away.

Data developed by BOEMRE, Office of Resource Evaluation, engineers and geoscientists include petrophysical analyses and 3-D seismic interpretations of the target sands. This information along with the data obtained from BP was transferred to the researchers once contracts were awarded and Data/Information Security Agreement forms were signed and returned to BOEMRE. The data were also uploaded to a secure ftp site developed by NOAA for the sharing of information between NOAA, DOE and BOEMRE.

5. Methodology

The researchers used different software packages to simulate reservoir performance and incorporated a variety of approaches to establish a range of possible outcomes. In addition, a detailed wellbore configuration provided by BOEMRE was incorporated into the models in order to develop a tubing lift curve to initiate production from the simulator.

Kelkar

Kelkar and Associates (Kelkar) used Schlumberger's Eclipse simulator to model reservoir performance. Kelkar developed sensitivities to several reservoir parameters and potential flow paths. One set of cases utilized base case/mean reservoir parameters with variations in flow path, choke size and pipe roughness. A second set of cases was developed using maximum reservoir parameters. Kelkar's forecasts also incorporated the effect of the installation of the Lower Marine Riser Package. Reservoir performance was simulated out to 116 days.

Hughes

R.G. Hughes and Associates (Hughes) used CMG's IMAX simulator to model reservoir performance. Hughes focused on developing sensitivities to structural interpretation using a fairly strong aquifer. Also, an initial blowout ramp up period was incorporated into these cases to reflect falling flowing bottomhole pressures during the first several days as the wellbore deteriorated. The flow path was assumed to be between the open hole and casing, and between the various casing strings. Reservoir performance was simulated out to 122 days.

Gemini

Gemini Solutions (Gemini) used GSI's Merlin simulator to model reservoir performance. Gemini developed sensitivities to reservoir parameters, potential flow paths and location of the OWC. In addition, the effects of 2-phase vertical flow correlations were investigated. The results of an absolute worst case scenario which reflected flow through multiple paths were also reported. Reservoir performance was simulated out to 10 years.

6. Results

The three independent researchers developed reservoir models for the targeted sands in BP's Macondo well and reported flow rates with associated bottomhole pressures and average reservoir pressures. The effects of reservoir and aquifer size, permeability variations and flow path were included in the analyses. In addition, all three researchers incorporated the initial wellbore configuration into their models and assumed annular flow as the base case. The range of possible outcomes reported for initial production rate is 27,300 to 102,607 BOPD.

Kelkar

Kelkar developed two sets of cases; one set using maximum values of fluid and reservoir parameters and the other using base case fluid and reservoir parameters. Each set includes 5 cases reflecting differing flow paths (tubing versus annular flow), choke diameters (2" versus 4" choke) and pipe roughness (smooth versus rough pipe). The range of values reported for initial flow rate is 27,300 to 45,400 BOPD (note: Kelkar's maximum production rates occur on the first day of the incident). The base case set forecasts rates between 27,300 and 31,500 BOPD and the maximum case set estimates initial rates between 36,800 to 45,400 BOPD.

In sensitivities developed by Kelkar, the researchers found that vertical flow performance curves based on assumed tubing and annular flow scenarios are more important than any static reservoir description parameter. Varying flow paths and choke sizes, resulted in a production rate impact of 9,000 BOPD, with rock, fluid and structural parameters held constant. After flow path, permeability was shown to influence rate significantly. Increasing permeability by 50 percent increased initial flow rate by 5,000 BOPD. Kelkar also reports that porosity and rock compressibility sensitivities had very little impact on production performance.

Hughes

Hughes developed two cases based on different reservoir structural assumptions. These cases assume different reservoir extents (sheet sand versus channel/levee complex) and fairly strong aquifer support. The flow path simulated was between the open hole and casing. The results show maximum flow rates from 63,157 to 65,531 BOPD (note: Hughes' maximum flow rates occur after a 10 day ramp up period). The flow path assumed by Hughes was also the same one incorporated into the other researchers' models and represents their most-likely flow scenario.

The results of Hughes' structural/stratigraphic interpretation sensitivity also showed that static reservoir parameters, apart from permeability, have a minimal impact on initial flow rate. Hughes' maximum case interpretation increased rate by only 1,400 BOPD.

Gemini

The data presented by Gemini includes a base case and 26 total sensitivities to structure, permeability, flow path and tubing flow correlations. The base case, assuming an infinite aquifer and an annular flow path, estimates an initial flow rate of 58,352 BOPD. The range of initial production rates reported is 40,564 to 102,607 BOPD (note: Gemini reports all production rates as daily average rates for a given week; maximum production rates provided are the daily average flow rate during the first week following the blowout. The output data were formatted in this manner due to the length of the simulation runs – 10 years).

Sensitivities to rock compressibility, aquifer size and location of OWC resulted in initial production rate changes of less than 1,000 BOPD, although a high permeability sensitivity increased rate by 2,000 BOPD and a low permeability case decreased rate by 7,000 BOPD. These results show that apart from permeability, variations in reservoir properties do not significantly affect initial production rate.

A sensitivity to reservoir extent supported Hughes' findings that showed little impact to initial production rate. Running the simulation out several years, however, showed that at 2 years, the case assuming a regional sheet sand had a daily production rate double that of the more limited case assuming a channel/levee complex with stratigraphic flow boundaries on two sides.

Gemini also ran several cases to test the model's sensitivity to four different flow correlations. Three of the correlations resulted in flow rates within 2,200 BOPD to each other (Hagedorn & Brown, Duns & Ross and Orkiszewski), while the fourth (Beggs and Brill) was ~14,000 BOPD greater than the others; the Beggs and Brill case predicted an initial rate of ~73,000 BOPD. The results of this analysis were used to determine the appropriate flow correlation for the base case; Gemini selected the Orkiszewski correlation.

Sensitivities to the flow path (annulus versus shoe failure) resulted in initial rate differences of over 16,000 BOPD, and the one high rate case which assumes all possible flow paths combined, generated a rate approximately 44,000 BOPD higher than the base case.

Reservoir Modeling Team

The reservoir Modeling Team developed Inflow Performance Relationship (IPR) curves for all cases submitted. These curves represent the relationship between flow rate and flowing bottomhole pressure at a specific time in the reservoir's life, and reflect fluid and rock properties at that time. The curves are designed to be used with outflow curves (tubing performance curves) to determine flow rate from the well. Discussions with the Nodal Analysis Team indicated that IPR curves were required for day 28 and day 56 after the blowout. These two curves were developed for each case and the data uploaded to the NOAA sftp site.

A preliminary statistical review of the results of the 39 cases submitted was conducted using Microsoft Excel. This analysis shows the 10th percentile at 32,688 BOPD and the 90th percentile at 63,432 BOPD.

One caveat concerning the production data generated by the researchers is that the data do not necessarily reflect changing tubing, drill pipe, BOP or riser configurations developed by the Nodal Analysis Team; this was not a necessary component of this project. The required output from this research was to generate data that could be used to develop inflow performance relationships for a variety of reservoir conditions. This requirement was fulfilled by the research teams.

6. Conclusions

1. Variations in reservoir properties such as rock compressibility and porosity, and OWC location, did not significantly affect initial production rate. Production rate variations of less than 1,000 BOPD were reported for these sensitivities.

2. Permeability uncertainties were shown to significantly affect production rate. A low permeability sensitivity resulted in decreasing the reservoir's productivity index (PI, *BOPD/psi*) by 50 percent; a high permeability case resulted in doubling the reservoir's PI.

3. Aquifer size variation had little impact on initial production rate; even after two years of production, significant variation between aquifer size cases was not observed. At five years, however, an infinitely acting aquifer case was forecasted to produce at a rate 50% greater than a 6:1 aquifer case; after 10 years, six times greater.

4. Different structural/stratigraphic interpretations impacting reservoir extent did not show a significant difference in initial flow rates. After 6 months, however, the two cases (sheet sand versus channel/levee complex) begin to diverge significantly; the sheet sand case forecasted a production rate 17 percent higher than the channel/levee complex case.

5. Four tubing flow correlations were tested in this study. Three of the methods (Hagedorn & Brown, Duns & Ross and Orkiszewski) showed similar results; one method (Beggs and Brill) resulted in a 24 percent higher initial production rate.

6. The variable with the greatest impact on flow rate from the Macondo well is the flow path. An annular flow path resulted in approximately 16,000 BOPD higher initial production rate (+38 percent) than a tubing/drill pipe flow model. When flow through all possible paths was considered, initial rate increased by 75 percent over the base case.