DISCUSSION

DRILLING AND PRODUCING HIGH PRESSURE SOUR GAS RESERVES

Chairman: H. F. SPÖRKER, OMV AG (Austria)

Scientific Secretary: T. S. CHILTON, Esso Exploration & Production UK Ltd. (UK)

The CHAIRMAN congratulated L. P. BROUSSARD on the excellent paper he had presented and stressed the importance of such a competent discussion of this problem.

The CHAIRMAN asked the first question and wanted to know the approximate cost of completing deep Mississippi sour gas wells including well site production facilities.

Mr. BROUSSARD stated that dry hole costs were in the order of US $10 million and the time required to drill such wells was somewhere between 10 and 12 months. For a producer it will cost another US $10 million for tubulars, well head, etc., plus US $5 million for surface safety installation. Thus total cost for a producer will add up to approximately US $25 million, plus or minus US $5 million, depending on whether you have no problems or whether you encounter difficulties.

H. KUERZL (FGR) mentioned that the authors had not addressed blowout preventers with regard to sour service equipment technology, and wanted to know their opinion on that question.

Mr. BROUSSARD answered that at present they were not too confident in the ability of blowout preventers to withstand sour gas for an extended period of time. As soon as sour gas reaches the surface it is produced through the permanent casing head system and oil base mud is injected through the blowout preventers.

H. G. GRAF (FRG) and C. MARX (FRG) asked for more information on pre-perforated linear versus cased hole completion.

The author replied that it is now possible to perforate at temperatures of 425 °F and pressures up to 25 000 psi, but it must be borne in mind that you are at the very edge of component specifications, including the wire line itself. As long as the hole produces dry gas—as is the case in Mississippi—a pre-perforated liner completion is preferred.

Professor GRAF also wanted to know whether there was elemental sulphur in the sour gas formation, or if elemental sulphur is formed in the tubing stream. If there is a sulphur plugging problem, where is the location of the plug which has to be overcome by a sulphur solvent? Certainly, with an H_2S-content in the produced gas of 35 to 45% you have to circulate oil continuously to maintain the sulphur in the oil and to prevent it from depositing in the tubing.

About the depth of the possible plugging point Mr. BROUSSARD said that they had no experience with this problem because they circulated oil continuously. But the point might be around 5000 ft.

In answer to a question from J. J. STOSUR (USA), the author said that they preferred to have the unrestricted ability to pump heavy mud down the well to control it if necessary. Mr. BROUSSARD agreed that there had been substantial improvements in subsurface safety valves.

Mr. POWELL (Canada) asked the author to comment on the use of any special jointing system for tubulars and any special chemistry required for thread compounds.

Mr. BROUSSARD replied that they had always given considerable attention to the sealing capabilities of the pressure string connections. They had developed some new connections with tension capabilities close to those of the pipe body, and sealing capabilities close to the burst pressure of the pipe body. They had always used API high temperature modified thread compound.

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C. BENTLEY (Netherlands) asked how many rotating hours were required on average inside the $10\frac{3}{4}''$ protective string before TD was reached at some 23 000 ft, and whether casing wear was monitored in any way.

Mr. BROUSSARD answered that he did not know the number of rotating hours, but casing wear was monitored. They try to drill a hole as straight as possible and if necessary the intermediate string is only cemented a short interval at the bottom, then cut and removed and a new string is run and cemented for completion. To a further question from H. CICHINI (Austria), Mr. BROUSSARD replied that a Dia-Log Service was used to check the internal wear of casing strings.

In answer to a question from J. J. DUBOIS (Belgium) on whether production tubulars are replaced every time they have to be pulled, the author stated that Shell had not had to pull a string of tubing since 1977. If internal corrosion were to be found, the tubings would be replaced, scaling at the outside surface would be removed by sandblasting and then the tubings would be re-run.

N. CIZMIC (Yugoslavia) wanted to know whether Shell has killing facilities, including the necessary mud volume, at each well, or whether they use a central installation for a field with lines to the individual wells.

Mr. BROUSSARD said that they were using both systems—it depended on the size of the field and the distance between the individual wells. But the intent is to have at least two well volumes available for each well which might have mechanical problems.

C. CHUR (FRG) asked: 'Do you have any experience with steel quality N-80 Q & T for casings in sour gas wells for temperatures below 65 °C? This quality is listed in NACE standard MR 01-75.'

Mr. BROUSSARD answered that they used some API-L80, to which they applied some additional quality assurance, and with a risk well even more attention is given to quality assurance. Low alloy steels with a minimum yield of 80 000 psi can be produced which are highly resistant to sulphide cracking.

Mr. BROUSSARD said, in answer to questions from F. LENZE (FRG): The 200 KSI material is a multiphase alloy, trade name MP 35 N, consisting of 37% Ni, 35% Co, rest Cr and only trace amounts of iron, and strength is achieved by cold working. Tool joint material for X-95 drill pipe is standard SAE 4140. It is better to protect them by the drilling fluid, i.e. high PH water muds or in severe cases oil base fluids.

T. R. BATES (USA) wanted to know (1) how many high strength corrosion resistant tubing strings have been installed, (2) are they inhibited, (3) have there been any operational problems with these tubing strings?

According to Mr BROUSSARD, they had completed some 12 to 14 wells using high alloy materials; the tubing strings were not inhibited and so more caution should be exercised with the thread connections.

A question from G. MOINS (France) was answered as follows: The Mississippi wells produce dry sour gas, but some wells in South Texas and in offshore areas have some condensate. Condensate is beneficial because less oil has to be circulated for corrosion control.

The last question came from Mr. TIEMER (FRG), who wanted to know whether solid block or an individual valve layout would be preferential for Christmas trees. The author replied that they had found a combination of some type of solid block for the lower valve configuration and then individual valves the best solution.

Concluding the session the CHAIRMAN again thanked the authors for their excellent paper, Mr. BROUSSARD for his interesting presentation and response to questions, and the audience for the interest shown.

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