

Natural Gas Hydrates *in* Flow Assurance

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Figure A.10

In the Merganser Field above, the system was restarted about an hour after shut-in. The MEG inhibitor was inadvertently not begun with well restart. After restart, the pressure gradually increased on ramp-up, indicating the formation of a hydrate deposit. Upon the pressure buildup the choke rate was reduced and MEG injection was begun, resulting in a hydrate dissociation. After the pressure had reduced the system production was increased, this time with MEG injection and normal pressures, without hydrate buildup.

Figure A.11

Jubilee 4 downstream choke pressure (psia) versus time. Note that the pressure first increased at 2:35 pm and the line plugged at 3:05 pm.

Figure A.12

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(Courtesy of Leon Field, © Chevron, 2009.)

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PREFACE

This is a condensed, updated version of earlier works to enable the flow assurance engineer to quickly answer seven questions:

- (1) How do hydrate plugs form?
- (2) How can hydrate plugs be prevented from forming?
- (3) How to deal safely with hydrate plugs?
- (4) How to remove a hydrate plug once it has formed?
- (5) How can kinetic inhibitors be certified?
- (6) What is the mechanism for naturally inhibited oils?
- (7) What are industrial hydrate case studies?

Our focus is offshore systems, from the reservoir to the platform, because these lines are the most inaccessible and, thus, the most problematic. However, almost all of the content can be applied to onshore processes and export lines from platforms.

The intent was to combine eight industrial flow assurance perspectives (from British Petroleum [BP], Chevron, ExxonMobil, and the Total Petroleum) with three perspectives from the Colorado School of Mines to enable resolution of hydrate design and operating problems. In a few pages the coauthors encapsulated knowledge from their careers to provide a basis for advancement by flow assurance engineers.

The trend over the last decade has focused on risk management to manage hydrates in field developments. Thus, the technical perspective of hydrate flow assurance is changing significantly, from avoidance to risk management. While industry previously chose to avoid having transportation equipment operate in the hydrate formation region of pressure and temperature (i.e., by inhibitor injection), a change in that earlier concept is to allow hydrate particles to form, while preventing hydrate plug formation. As this book illustrates, both economic and technical incentives are provided by adding new hydrate risk management tools to the existing tools of hydrate avoidance.

Our intention was to combine the practical experience of industry together with the concepts generated in academia, to state in this concise volume the basics of the new risk-management methods. We gratefully acknowledge the flow assurance engineers who contributed to enable this book: John Abrahamson, Alex Alverado, Guro Aspenes, Torstein Austvik, Ray Ayres, Jim Bennett, Gary Bergman, Phaneendra Bollavaram, John

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